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August 4, 2014

VIA HAND DELIVERY

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
P.O. Box 3265
Harrisburg, PA 17105-3265

Re: Metropolitan Edison Company – General Base Rate Filing
Docket No. R-2014-2428745

Dear Secretary Chiavetta:

INTRODUCTION AND CONTENTS OF THE FILING

Pursuant to Section 1308 of the Pennsylvania Public Utility Code, 66 Pa.C.S. § 1308, enclosed for filing on behalf of Metropolitan Edison Company ("Met-Ed" or the "Company") is Met-Ed's Tariff Electric – Pa. P.U.C. No. 52 ("Tariff No. 52"), which has been marked for identification as Met-Ed Company Exhibit No. 1. Tariff No. 52 sets forth proposed rates designed to produce an increase in the Company's annual distribution revenue of $151.9 million based on data for a fully projected future test year ending April 30, 2016. Tariff No. 52 also contains revisions in, additions to, and deletions from, certain Rules and Regulations, rate schedules and riders in the Company's currently effective tariff. Tariff No. 52 bears an issue date of August 4, 2014, and an effective date of October 3, 2014.

Along with Tariff No. 52, the Company is filing all the supporting data required by the Pennsylvania Public Utility Commission's ("PUC" or "Commission") regulations at 52 Pa. Code §§ 53.52 – 53.53, including the written direct testimony of ten witnesses, who are identified in Met-Ed Exhibit No. CVF-2. A summary of the reasons for the proposed rate increase is set forth in the Company's Statement of Reasons, which is marked for identification as Met-Ed Exhibit No. CVF-1.

The Company is filing one complete hard copy and one electronic copy, on the enclosed CD, of its entire filing. An index cross-referencing the contents of the Company's supporting data and the Commission's filing requirements is attached as Appendix A to this transmittal letter.

TEST YEAR – WAIVER OF THE "120-DAY" RULE

As the Commission is aware, on June 24, 2014, Met-Ed requested permission to depart from the provision of 52 Pa. Code § 53.52(b)(2) limiting to 120 days the period between the end of a historic test year and the date on which an increase in base rates under Section 1308(d) of the Pennsylvania Public Utility Code (66 Pa.C.S. § 1308(d)) may be filed reflecting that historic test year. By letter dated June 30, 2014, the Commission granted the Company permission to file for a general base rate increase on or before August 14, 2014, employing a historic test year ended March 31, 2014. Accordingly, the Company is submitting supporting data for a historic test year ended on that date, a future test year ending March 31, 2015, and, as previously noted, a fully projected future test year ending April 30, 2016. In support of its proposed increase in distribution revenues, the Company is relying principally on data for the fully projected future test year.

USE OF ALTERNATIVE METHOD OF CUSTOMER NOTIFICATION

Met-Ed hereby advises the Commission that it has elected to use the alternative method of customer notification set forth in the Commission's regulations at 52 Pa. Code § 53.45(b)(4). Consequently, as required by that regulation, Met-Ed will notify its customers of the proposed rate increase through bill inserts along with paid advertisements in major local newspapers.[1] Met-Ed also agrees to extend from 60 to 90 days the minimum period within which the filing of a complaint places the burden of proof upon the Company with respect to proposed rates, pursuant to 52 Pa. Code § 53.45(b)(4)(vi).

REQUEST FOR CONSOLIDATION

This filing is being made contemporaneously with general rate increase filings by Met-Ed's Pennsylvania affiliates at the docket numbers identified below:

Pennsylvania Electric Company ("Penelec")	R-2014-2428743
Pennsylvania Power Company ("Penn Power")	R-2014-2428744
West Penn Power Company ("West Penn")	R-2014-2428742

Pursuant to 52 Pa. Code § 5.81, Met-Ed, by this transmittal letter, and Penelec, Penn Power and West Penn, in their respective transmittal letters, request that proceedings initiated with regard to their rate filings be formally consolidated by the Commission at the earliest possible opportunity. There is a fundamental commonality to virtually all of the components of the Companies' revenue requirements, rate designs and changes in various tariff provisions. Consequently, proceedings initiated by the Commission will involve a substantial number of common questions of law and fact. The resources of the Commission and all parties would be

[1] In addition, Met-Ed is posting notice of this filing at its Company headquarters pursuant to 52 Pa. Code § 53.45(b)(1), posting the filing to its website, and issuing a news release describing the proposed changes to local newspapers, radio and television stations pursuant to 52 Pa. Code § 53.45(b)(2).

used most efficiently and cost effectively, and administrative economy would be advanced, by formally consolidating the proceedings initiated with respect to all of the Companies' rate filings.

REQUEST FOR CONFIDENTIAL TREATMENT OF PROPRIETARY INFORMATION

Met-Ed Exhibit No. RAD-40 contains information that Met-Ed considers to be proprietary and confidential. These pages have been marked ***Highly Confidential,*** are enclosed in separate envelopes and have not been included in the electronic version of the filing.

Met-Ed requests that the copies of the material that have been marked ***Highly Confidential*** and are contained in the envelopes similarly marked ***Highly Confidential*** be treated confidentially by the Commission, including its various Offices and Bureaus. In particular, the Company requests that the ***Highly Confidential*** material be excluded from the Commission's public document folder and not otherwise be disclosed to the public. Met-Ed intends to request the entry of an appropriate Protective Order from the presiding Administrative Law Judge(s) to maintain the confidentiality of such material if it is to be provided to parties in this case.

COUNSEL OF RECORD AND SERVICE ON THE COMPANY

Met-Ed will be represented by the following counsel in this proceeding:

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Met-Ed's attorneys are authorized to accept service on behalf of the Company in this proceeding. Met-Ed requests that the Commission and all parties serve copies of all documents in this proceeding on its attorneys.

CERTIFICATE OF SERVICE

As indicated on the attached Certificate of Service, the Company has served copies of this filing on the Commission's Bureau of Investigation and Enforcement, the Office of Consumer

Advocate, the Office of Small Business Advocate, Pennsylvania State University, and industrial customer groups. The Company is also providing courtesy copies of the filing to the Commission's Law Bureau, Office of Special Assistants, and Bureau of Technical Utility Services.

Respectfully submitted,

Tori L. Giesler

Enclosures

c: Certificate of Service (w/encls.)
Robert F. Powelson, Chairman (w/encls.)
John F. Coleman, Jr., Vice Chairman (w/encls.)
James H. Cawley, Commissioner (w/encls.)
Pamela A. Witmer, Commissioner (w/encls.)
Gladys M. Brown, Commissioner (w/encls.)
Bohdan R. Pankiw, Chief Counsel (w/encls.)
Cheryl Walker Davis, Director (w/encls.)
Paul T. Diskin, Director (w/encls.)

METROPOLITAN EDISON COMPANY

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Exhibit CVF-4	I-B-1	Corporate History
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Electric Pa. P.U.C. No. 52
Cancels Contents of and
Supersedes Electric Pa. P.U.C. No. 51

METROPOLITAN EDISON COMPANY

READING, PENNSYLVANIA

Electric Service Tariff

Effective in

The Territory as Defined on
Page Nos. 8 - 10 of this Tariff

Issued: August 4, 2014 **Effective: October 3, 2014**

By: Charles E. Jones, Jr., President
Reading, Pennsylvania

NOTICE

LIST OF MODIFICATIONS

General

This new Tariff establishes new Rules and Regulations, Rate Schedules, Services, and Riders for Metropolitan Edison Company.

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DESCRIPTION OF TERRITORY

EASTON AREA

Bucks County - Borough of Riegelsville.
Townships of Bridgeton, Durham, Nockamixon and Tinicum.

Monroe County - Boroughs of Delaware Water Gap, East Stroudsburg and Stroudsburg
Townships of Chestnuthill, Hamilton, Middle Smithfield, Price, Ross, Smithfield and Stroud.

Northampton County - City of Easton.
Boroughs of Bangor, Bath, Chapman, East Bangor, Glendon, Nazareth, Pen Argyl, Portland, Roseto, Stockertown, West Easton, Wilson and Wind Gap.

Townships of Allen, Bethlehem, Bushkill, East Allen, Forks, Lehigh, Lower Mt. Bethel, Lower Nazareth, Moore, Palmer, Bplainfield, Upper Mt. Bethel, Upper Nazareth, Washington and Williams.

Pike County - Townships of Delaware, Dingman and Lehman.

READING AREA

Berks County - City of Reading.

Boroughs of Bally, Bechtelsville, Bernville, Birdsboro, Boyertown, Centerport, Fleetwood, Hamburg, Kenhorst, Kutztown, Laureldale, Leesport, Lenhartsville, Lyons, Mohnton, Mt. Penn, St. Lawrence, Shillington, Shoemakersville, Strausstown, Temple, Topton, West Reading and Wyomissing.

Townships of Albany, Alsace, Amity, Bern, Brecknock, Centre, Colebrookdale, Cumru, District, Douglass, Earl, Exeter, Greenwich, Hereford, Jefferson, Longswamp, Lower Alsace, Maidencreek, Maxatawny, Muhlenberg, North Heidelberg, Oley, Ontelaunee, Penn, Perry, Pike, Richmond, Robeson, Rockland, Ruscombmanor, Spring, Tilden, Union, Upper Bern, Washington and Windsor.

Chester County - Township of Warwick.

Lancaster County - Borough of Adamstown.
Township of Brecknock.

DESCRIPTION OF TERRITORY (continued)

READING AREA (continued)

Lehigh County - Townships of Lowhill, Lynn and Weisenberg.

Montgomery County - Townships of Douglass, Lower Pottsgrove, Upper Frederick, New Hanover and Upper Pottsgrove.

LEBANON AREA

Berks County - Borough of Womelsdorf.
Townships of Bethel, Jefferson, Marion, Tulpehocken, and Upper Tulpehocken.

Dauphin County - Borough of Middletown.
Townships of Conewago, Derry, East Hanover, Londonderry and Lower Swatara.

Lancaster County - Township of Conoy and West Donegal.

Lebanon County - City of Lebanon.

Boroughs of Cleona, Cornwall, Jonestown, Mt. Gretna, Myerstown, Richland and Palmyra.

Townships of Annville, Bethel, Cold Spring, East Hanover, Heidelberg, Jackson, North Annville, North Cornwall, North Lebanon, North Londonderry, South Annville, South Lebanon, South Londonderry, Swatara, Union, West Cornwall and West Lebanon.

YORK AREA

Adams County - Boroughs of Abbottstown, Arendtsville, Bendersville, Biglerville, Bonneauville, Carroll Valley, East Berlin, Fairfield, Gettysburg, Littlestown, McSherrystown, New Oxford and York Springs.

Townships of Berwick, Butler, Conewago, Cumberland, Franklin, Freedom, Germany, Hamilton, Hamiltonban, Highland, Huntington, Latimore, Menallen, Mt. Joy, Mt. Pleasant, Oxford, Reading, Straban, Tyrone and Union.

Cumberland County - Borough of Mt. Holly Springs.
Townships of Cooke, Dickinson, Monroe, South Middleton and Upper Allen.

DESCRIPTION OF TERRITORY (continued)

YORK AREA (continued)

Dauphin County - Township of Londonderry.

York County - City of York.
Boroughs of Cross Roads, Dallastown, Dillsburg, Dover, Fawn Grove, Felton, Franklintown, Glen Rock, Hallam, Hanover, Jacobus, Jefferson, Loganville, Manchester, Mount Wolf, New Freedom, New Salem, North York, Railroad, Red Lion, Seven Valleys, Shrewsbury, Spring Grove, Stewartstown, Wellsville, West York, Windsor, Winterstown, Wrightsville, Yoe, York Haven and Yorkana.

Townships of Carroll, Chanceford, Codorus, Conewago, Dover, East Hopewell, East Manchester, Fairview, Fawn, Franklin, Heidelberg, Hellam, Hopewell, Jackson, Lower Windsor, Manchester, Manheim, Monaghan, Newberry, North Codorus, North Hopewell, Paradise, Penn, Shrewsbury, Springettsbury, Springfield, Spring Garden, Warrington, Washington, West Manchester, West Manheim, Windsor and York.

GENERAL RULES AND REGULATIONS

GENERAL APPLICATION

This Tariff may be revised, amended, supplemented or otherwise changed from time to time by the Company in accordance with prevailing Commission regulations.

This Tariff sets forth the conditions under which various retail services shall be supplied by the Company. Unless stated specifically otherwise, this Tariff shall apply throughout the Company's entire service area.

This Tariff applies to the Company's provision of Delivery Service and various retail services that may be provided by the Company. Regardless of the type of service provided to Customers, all electric energy shall be alternating current, sixty (60) hertz frequency, at such standard nominal voltages and phases as may be available or specified by the Company from time to time. Electric service shall be delivered by the Company from overhead supply lines, except (i) in certain restricted areas where the Company elects to provide an underground network system of distribution and/or (ii) where other underground facilities are installed pursuant to specific provisions of this Tariff.

The rate schedules, rules and regulations governing electric service as herein contained, are subject to termination, change or modification by posting, filing, and publishing any subsequent rate schedule or supplement in accordance with the Public Utility Law or under order or by permission of the Pennsylvania Public Utility Commission. No agent, representative or employee of the Company has any right to modify or alter any provision of the Company's schedule of rates, rules and regulations.

DEFINITIONS

The following is a list of some of the most commonly used terms in this Tariff. All capitalized terms referenced in this Tariff shall be defined as set forth below or as otherwise defined in any particular Rule, Rate Schedule or other Provision hereof. In the event of a conflict between any of the definitions set forth below or those contained in a more specific provision of this Tariff, the definition contained in the more specific provision shall prevail.

Act 129 – Act 129 of 2008, amending Title 66 of the Pennsylvania Consolidated Statutes.

Advanced Metering - A Customer's billing meter as defined in 52 Pa. Code Chapter 57, Subchapter O. Advanced Meter Deployment.

GENERAL RULES AND REGULATIONS

Definition of Terms (continued)

Alternative Energy Portfolio Standards ("AEPS") – Standards requiring that a certain amount of electric energy sold from alternative energy sources be included as part of the sources of electric utilities within the Commonwealth of Pennsylvania in accordance with the Alternative Energy Portfolio Standards Act, 73 P.S. §1648.1 – 1648.8 ("AEPS Act") as may be amended from time to time.

Applicant - Any person, corporation or other entity that (i) desires to receive from the Company electric or any other service provided for in this Tariff, (ii) complies completely with all Company requirements for obtaining electric or any other service provided for in this Tariff, (iii) has filed and is awaiting Company approval of its application for service, and (iv) is not yet actually receiving from the Company any service provided for in this Tariff. For Residential Service, an Applicant is a natural person not currently receiving service who applies for Residential Service or any adult occupant whose name appears on the mortgage, deed or lease of the property for which the Residential Service is requested unless specifically stated otherwise in this Tariff, an Applicant shall become a Customer for purposes of this Tariff only after it actually starts receiving the applicable service(s) from the Company under this Tariff.

Basic Electric Supply – For purposes of the Company's Purchase of EGS Receivables Program, energy (including renewable energy) and renewable energy or alternative energy credits (RECs/AECs) procured by an EGS, provided that the RECs/AECs are bundled with the associated delivered energy. For residential Customers, Basic Electric Supply does not include early contract cancellation fees, late fees, or security deposits imposed by an EGS.

Black Start Service - The ability of a Generating Facility to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system (i.e., the Company's electrical system).

Cash Advance - A refundable contribution in cash from an Applicant for those costs associated with a Line Extension, increased for applicable taxes, which is held by the Company in a non-interest bearing account.

GENERAL RULES AND REGULATIONS

Definition of Terms (continued)

Combined Billing - The aggregation of the billing determinants of two or more meters of the same Customer at the same location for billing purposes.

Commercial Customer Class – Rate Schedules GS-Small, GS-Medium, MS, Borderline Service, Street Lighting Service, Ornamental Street Lighting Service, LED Street Lighting Service, and Outdoor Lighting Service.

Commission - The Pennsylvania Public Utility Commission or any lawful successor thereto.

Community Association - A formal organization (including unit owners' associations) of persons, whether incorporated or unincorporated, having rights in a residential development; such organizations having been formed to provide services (including, but not limited to, street lighting services) to the residential development where such services are not provided by a municipality.

Company - Metropolitan Edison Company.

Competitive Energy Supply – The unbundled energy, capacity, market based transmission and ancillary services provided by an Electric Generation Supplier pursuant to the Customer Choice and Competition Act.

Connected Load - The sum of the horsepower, kilowatts or kilovolt ampere ratings of all the devices located on a Customer's premises that are connected to the Company's electric system, or which can be connected simultaneously by the insertion of fuses or by the closing of a switch. The manufacturer's nameplate rating may be used to determine the input rating of a particular device. In the absence of such manufacturer's rating, or whenever a Company test indicates improper rating of a device, the rating shall be determined on the basis of the kilovolt-amperes required for its operation.

Consolidated Billing –The issuance of a bill to the Customer by the Company that includes Delivery Service Charges and the charges imposed upon the Customer by an Electric Generation Supplier with whom the Customer has contracted for Competitive Energy Supply.

Contract Demand - The capacity required for operation of an Applicant's/Customer's equipment, as stated in any application or contract for service.

Contractor Costs - The amounts paid by the Company for work performed by a contractor retained by the Company.

GENERAL RULES AND REGULATIONS

Definition of Terms (continued)

Contributions in Aid of Construction ("CIAC") - A non-refundable contribution in cash from an Applicant for those costs associated with a Line Extension and/or tree trimming, brush clearance and related activities or those costs associated with Temporary Service or the relocation of Company facilities, increased for applicable taxes.

Customer(s) - Any person, partnership, association, corporation, or other entity (i) in whose name a service account is listed, (ii) who occupies or is the ratepayer for any premises, building, structure, etc. or (iii) is primarily responsible for payment of bills. For Residential Service, a Customer is a natural person in whose name a Residential Service account is listed and who is primarily responsible for payment of bills rendered for the service or any adult occupant whose name appears on the mortgage, deed, or lease of the property for which the Residential Service is being received. A Customer includes anyone taking Delivery Service under this Tariff.

Customer Choice and Competition Act - The Pennsylvania legislation known as the "Electricity Generation Customer Choice and Competition Act," 66 Pa. C. S. §§ 2801-2813 as implemented by the Default Service Regulations 52 Pa. C. S. §§52.181-52.189, and by Act 129 and as may be amended from time to time.

Default Service – Service provided pursuant to a Default Service Program to a Default Service Customer.

Default Service Customer – A Delivery Service Customer not receiving service from an EGS.

Delivery Service - Provision of distribution of electric energy and other services provided by the Company.

Delivery Service Charge - A charge that includes the Monthly Minimum Charge, Distribution Charge, and all charges and surcharges imposed under other applicable tariff provisions.

GENERAL RULES AND REGULATIONS

Definition of Terms (continued)

Delivery Service Customer - A Customer who takes Delivery Service.

Demand - The rate of use of electric energy during a specified time interval, expressed in kilowatts and reactive kilovolt-amperes.

Developer - The person or entity responsible for constructing and providing improvements in a Development, including, but not limited to, streets, sidewalks and utility-ready lots.

Development - A planned project which is developed by a Developer for electric service set out in a recorded plot plan of five (5) or more adjoining unoccupied lots for the construction of single-family residences, detached or otherwise, mobile homes, or one (1) or more five-unit apartment houses, all of which are intended for year-round occupancy, if electric service to such lots necessitates extending the Company's existing Distribution Lines.

Direct Labor Costs - The pay and expenses of Company employees directly attributable to work performed, excluding construction overheads or payroll taxes, workmen's compensation expenses or similar expenses.

Direct Material Costs - The purchase price of materials used, excluding related stores (i.e. warehousing) expenses. In computing Direct Material Costs, proper allowance shall be made for unused materials recovered from temporary structures, and for discounts allowed and realized in the purchase of materials.

Discontinuance of Service - The removal of a customer's meter and/or service wires or the de-energizing of a meter.

Distribution Charge - A charge designed to recover the costs the Company incurs in using its distribution system or local wires to deliver electricity to a Customer.

Distribution Line - An electric supply line and related equipment of 34,500 volt wye configured or lower voltage from which energy is delivered to one (1) or more Service Lines.

GENERAL RULES AND REGULATIONS

Definition of Terms (continued)

Electric Generation Supplier (EGS) - EGS shall have the meaning as set forth in the Customer Choice and Competition Act.

Energy Charge – A charge based upon kilowatt-hours of use.

Energy Efficiency and Conservation Charge – A reconcilable, non-by-passable charge applied to each Billing Unit during a billing month to Delivery Service Customers, with the exception of those served under Borderline Service, pursuant to the terms of the Phase II Energy Efficiency and Conservation Rider.

FERC – The Federal Energy Regulatory Commission

Generating Facility - Any equipment and/or facility that is electrically interconnected to the Company and is (i) capable of generating electrical energy for delivery into the PJM control area and (ii) is located on a single site within the Company's service territory. A single site with multiple generating units, each owned by a single entity, shall constitute one Generating Facility. The Company shall have the sole and exclusive right to determine if any particular equipment qualifies as a Generating Facility if the operating characteristics and/or circumstances relating to such equipment are different than described in this definition.

Hertz – A unit of frequency, equal to one cycle per second.

Horsepower (HP) – Unit of mechanical power representing rate of consumption of power and equivalent to 746 watts. As used herein, horsepower is computed as the equivalent of 750 watts.

Hourly Pricing Service Charges – For Customers served under Rate Schedules GS-Large, GP, TP, as well as GS-Small and GS-Medium Customers that elect this rate, the charges representing the Company's costs for providing energy, capacity, including the cost of complying with non-solar AEPS, transmission, and ancillary services for Default Service Customers.

GENERAL RULES AND REGULATIONS

Definition of Terms (continued)

Individualize Contract – Shall have the meaning ascribed to it in Rule 14.

Industrial Customer Class – Rate Schedules GS-Large, GP and TP.

Kilovar (KVAR) - 1,000 volt-amperes reactive.

Kilovolt-ampere (KVA) - 1,000 volt-amperes.

Kilowatt (KW or kW) - 1,000 watts.

Kilowatt-hour (KWH or kWh) - 1,000 watts for one (1) hour.

Line Extension - The extension of the Company's distribution system from the nearest suitable and available Distribution Line to the Service Line which will provide service to the Customer.

Monthly Minimum Charge – A charge designed to recover the costs the Company incurs in billing a Customer's account and providing other services.

Net Station Power - The quantity of electrical energy and/or capacity actually provided by the Company to the Generating Facility for Station Power during an applicable period after crediting the amount, if any, of electric energy during the applicable period (i) produced by the Generating Facility and delivered into the PJM control area or (ii) as permitted under "Station Power Energy Netting" as described in the applicable Rate Schedule.

Network Integration Transmission Service – Network Integration Transmission Service as set forth in the PJM Open Access Transmission Tariff and any direct Transmission Owner charged expense.

Network Service Peak Load (NSPL) – A Customer's one (1) coincident peak kW Network Service Peak Load in effect from time to time, as calculated by the Company in accordance with PJM rules and requirements.

GENERAL RULES AND REGULATIONS

Definition of Terms (continued)

Non-Profit Ambulance Service - Any nonprofit chartered corporation, association, or organization located in the Commonwealth of Pennsylvania which (i) is regularly engaged in the service of providing emergency medical care and transportation of patients, (ii) possesses all necessary legal authority in Pennsylvania to perform emergency medical care and transportation of patients and (iii) provides such services from a building or other structure located in the Company's service territory that constitutes a separately metered location for electric delivery purposes. The electric service used by the Non-Profit Ambulance Service shall be primarily to support its service. The Customer/Applicant shall provide all documentary and other evidence of its compliance with this provision if requested by the Company in its sole discretion.

Non-Profit Rescue Squad - Any nonprofit chartered corporation, association, or organization located in the Commonwealth of Pennsylvania which (i) is regularly engaged in providing rescue services, (ii) possesses all necessary legal authority in Pennsylvania to perform rescue services and (iii) provides such services from a building or other structure located in the Company's service territory that constitutes a separately metered location for electric delivery purposes. The electric service used by the Non-Profit Rescue Squad shall be primarily to support its service. The Customer/Applicant shall provide all documentary and other evidence of its compliance with this provision if requested by the Company in its sole discretion.

Non-Profit Senior Citizen Center - A separately metered service location comprised of a building or other structure used by senior citizens as a meeting or gathering facility for individuals or groups, and where services to senior citizens are provided. The Customer of record at this service location shall be an organization recognized by the Internal Revenue Service as non-profit and by the Department of Aging as an operator of a senior citizen center.

Non-Speculative Line Extension - A Line Extension for a Permanent Residential Customer under which the Company has taken into account various factors including, but not limited to, Customer location, rate classification, projected Company revenues, permanency of use, primary residence and prospect of use by future Customers, and has deemed the cost for the Line Extension to be reasonable for the Company to incur.

GENERAL RULES AND REGULATIONS

Definition of Terms (continued)

Non-Summer – The calendar months of October through May.

Non-Utility Generation Charge or NUG Charge – A reconcilable, non-by-passable charge or credit applied to each kWh delivered during a billing month to Delivery Service Customers pursuant to the terms of the Non-Utility Generation Charge Rider.

NUG - Non Utility Electric Generating Facility

On-Peak Hours – Hours to be considered as on-peak for billing purposes for energy and demand charges are 9:00 AM to 5:00 P.M or 10:00 AM to 6:00 P.M prevailing time, at the option of the Customer, Mondays to Fridays inclusive except New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Permanent Residential Customer - A Customer occupying a dwelling or mobile home on a permanent foundation which is the Customer's primary residence occupied year-round for normal living purposes and including: (i) electrical wiring conforming with the National Electrical Code and the Company's service installation policies; (ii) a permanently installed heating system; and (iii) permanently installed plumbing and sewage systems.

PJM - PJM Interconnection, L.L.C. or any successor organization/entity thereto.

Point of Delivery - The location at which the Company service connection terminates and the Customer's wiring and installation begins.

Power Factor - The ratio of the watts to the volt-amperes.

Price to Compare Default Service Charge – The cents per kWh rates representing the Company's costs for providing energy, capacity, including the cost of complying with non-solar AEPS, market based transmission and ancillary services for Customers who take Default Service.

Primary Voltage - Voltage greater than 600 volts.

Private Right-of-Way - The right-of-way or easement for electric facilities on, over, under, across and/or through real or other property owned by an individual or entity which is not a governmental, municipal or other public body to provide service.

GENERAL RULES AND REGULATIONS

Definition of Terms (continued)

Public Right-of-Way - The right-of-way or easement for electric facilities, subject to reasonable permitting, on, over, under, across and/or through real or other property owned by a governmental, municipal or other public body to provide service.

Purchase of EGS Receivables ("POR") Program - The Company will purchase the account receivables associated with EGS sales of Competitive Energy Supply. The Company will purchase only those receivables that are associated with Basic Electric Supply services and not receivables associated with charges for other products or services.

Rate Schedule - The specific set of terms and conditions (including prices) applicable to Customers and identified as such under this Tariff.

Real Time Hourly LMP - Shall have the meaning specified in the PJM Open Access Transmission Tariff.

Residential Customer - Customers using single phase service for residential lighting, appliance operation and general household purposes, or for the combined residential and incidental non-residential purposes.

Residential Customer Class – Rate Schedules RS and GS-Volunteer Fire Company, and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service.

Residential Service - Electric service under the Company's Residential Rate Schedules that is available to: (i) an individual dwelling unit, generally a house, mobile home or an individually metered apartment, where there is no more than 2,000 watts connected load associated with any commercial enterprise served as part of said dwelling unit, house, mobile home or individually metered apartment; (ii) a residential farm where the metered service includes service to an occupied dwelling unit; (iii) a camp or cottage served in the name of an individual and intended for part-time occupancy as a dwelling by a family or an individual; or (iv) multiple dwellings, where specified in any applicable Residential Rate Schedule. Residential Service does not include electric service to: (i) any facility not including an occupied dwelling unit, such as a separately metered garage, barn, water pump, etc.; and/or (ii) any facility served in the name of, or for the use of, a corporation, partnership, association, society, clubs, etc., not being used as a single dwelling unit.

GENERAL RULES AND REGULATIONS

Definition of Terms (continued)

Secondary Voltage - Voltage of 600 volts or less.

Service Line - An electric supply line from the Distribution Line to the Customer's metering point from which electric service is delivered to the Customer.

Smart Meter Technologies Charge Rider – A reconcilable, non-by-passable charge applied as a monthly Customer charge during each billing month to Delivery Service metered Customers, excluding Street Lighting Service, Ornamental Street Lighting Service, Outdoor Lighting Service, LED Street Lighting Service, and Borderline Service pursuant to the terms of the Smart Meter Technologies Charge Rider.

Solar Photovoltaic Requirements Charge or SPVRC – A reconcilable, non-by-passable charge applied to each kWh delivered during a billing month to Delivery Service Customers pursuant to the terms of the Solar Photovoltaic Requirement Charge Rider.

Speculative Line Extension - A Line Extension in which the Company has taken into account various factors including, but not limited to, Customer location, rate classification, projected Company revenues, permanency of use, primary residence and prospect of limited use by future Customers, and has deemed the cost of the Line Extension to be unreasonable for the Company to incur.

Station Power - The electrical energy used for operating the electric equipment on the site of a Generating Facility located in the PJM control area or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a Generating Facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers, (ii) used for pumping at a pumped storage facility, (iii) used in association with restoration or Black Start Service or (iv) that is normally supplied to any buildings, structures, facilities, etc. on the site of such a Generating Facility that are metered separately and served directly from the Company's distribution system. Energy provided for the uses described in subparagraphs (i) - (iii) above constitute wholesale transactions, and energy provided for the uses described in subparagraph (iv) above are retail transactions which will continue to be billed under the applicable Rate Schedule.

Subdivider - The person or entity responsible for dividing a tract of land into building lots, to form a Subdivision, that are not to be sold as utility-ready lots.

GENERAL RULES AND REGULATIONS

Definition of Terms (continued)

Subdivision - A tract of land divided by a Subdivider into five (5) or more adjoining unoccupied lots for the construction of single-family residences, detached or otherwise, or apartment houses, all of which are intended for year-round occupancy, if electric service to such lots necessitates extending the Company's existing Distribution Lines.

Summary Billing – The summation of the charges for a Customer's multiple accounts and provision thereof to the Customer in a single bill.

Summer – The calendar months of June through September.

Temporary Electric Service - A Service Line, meter and/or other work supplied by the Company to the Customer for electric service over a defined period, usually less than one (1) year.

Tariff - This document, including, but not limited to, the Rules, Regulations and Rate Schedules and Riders contained herein, as filed with and approved by the Commission.

Transmission Voltage - Voltage equal to or greater than 34,500 volts delta.

Universal Service – Policies, protections and services that help residential low-income Customers maintain electric service. The term includes Customer assistance programs, termination of service protections and policies and services that help low-income Customers to reduce or manage energy consumption in a cost-effective manner.

Universal Service Charge – The charge developed and calculated in accordance with Rider C – Universal Service Cost Rider.

Volunteer Fire Company - A service location consisting of a building, sirens, a garage for housing vehicular firefighting equipment, or a facility certified by the Pennsylvania Emergency Management Agency (PEMA) for fire fighter training. The use of electric service at this service location shall be to support the activities of the Volunteer Fire Company. Any fund raising activities at this service location must be used solely to support volunteer fire fighting operations. The Customer of record at this service location must be predominately a Volunteer Fire Company recognized by the local municipality or PEMA as a provider of firefighting services.

GENERAL RULES AND REGULATIONS

HOW TO OBTAIN SERVICE/CHANGES TO SERVICE

1. Applications/Contracts

All Applicants desiring any type of service from the Company under this Tariff shall contact the Company and specifically request the type and nature of service.

If more than one Rate Schedule is available for any service, the Company will assist the Customer initially in selecting the Schedule which, on the basis of the Customer's advice to the Company regarding the anticipated service conditions, is most advantageous. If, as a result of a permanent change in the Customer's service conditions, another Rate Schedule becomes more advantageous to the Customer, the Company will, after written notice by the Customer of such change, recommend such other Rate Schedule.

A Non-Residential Applicant for any service under this Tariff may be required to sign an application and/or a contract for electric service. However, the Company may, in its sole discretion, accept an oral application from a Non-Residential Applicant.

The Company shall accept an oral application from a Residential Applicant, except that the Company may require a written application from a Residential Applicant if the Company believes that positive identification is necessary.

The Customer shall inform the Company in advance of any proposed additions to (or decreases in) the Customer’s connected electrical load. The Company may, in its sole discretion, require a written application and or contract for changes in load or services.

The minimum term of contracts for any type of electric service under this Tariff shall be as stated in the applicable Rate Schedule(s) or any other provisions of this Tariff. Unless otherwise specified in any particular Rate Schedule or any other provisions of this Tariff, the term of any contract for any type of electric service under this Tariff that requires a contract term of not less than one (1) year shall commence on the date specified by the Company and terminate on the Customer’s closest scheduled meter read date on or after twelve (12) months from the commencement date of such contract.

The Company may require, as a condition of the furnishing of service to an Applicant, the payment of any outstanding account (limited to the portion that was for regulated service provided by the Company) in the Applicant's name which accrued within the past four years or for any outstanding account for which the Applicant is determined to be legally responsible and for which the Applicant was properly billed.

GENERAL RULES AND REGULATIONS

Applications/Contracts (continued)

The Company may require an Applicant/Customer to make the payment of any outstanding balance or portion of an outstanding balance if the Applicant/Customer resided at the property for which service is requested during the time the outstanding balance accrued and for the time the Applicant/Customer resided at the property not to exceed four years. The Company may establish that an Applicant/Customer previously resided at a property through the use of mortgage, deed, lease information, a consumer credit reporting service, a Financial Summary that provides the names and income of adult occupants of a household, and a web-based tool such as "Accurint" to research Applicant/Customer information.

2. Deposits

Where an Applicant's/Customer's credit is not established or the credit of a Customer with the Company has, in the Company's judgment become impaired, or where the Company deems it necessary, a deposit or other guarantee satisfactory to the Company may be required to be supplied by the Applicant/Customer as security for the payment of future and final bills before the Company shall commence or continue to render any type of electric service to the Applicant/Customer. Deposits required by the Company for Tariff charges shall include unpaid EGS charges that are subject to the Company's POR.

The Company may request deposits from Customers taking service for a period of less than thirty (30) days, in an amount equal to the estimated bill for the cost of total services provided by the Company for such temporary period. Deposits may be required by the Company from all other Customers, in an amount that is equal to one-sixth (1/6) of the Applicant's/Customer's estimated annual bill at the time the Company determines a deposit is required. If the total of the Applicant's/Customer's bill in any two consecutive months exceeds the amount of the deposit, the Company may require that the deposit be proportionately increased.

Deposits for Residential Customers shall be returned to them in accordance with the provisions of the Responsible Utility Customer Protection Act (66 Pa. C.S. §§ 1401-1418) and the provisions of the Commission's Regulations at 52 Pa. Code Chapter 56, as amended from time to time. Deposits from all other Customers may be held by the Company, in its sole and exclusive judgment, until the Customer discontinues service or the Company determines that the Customer has established a satisfactory payment record. Upon discontinuance of all Company service and payment in full of all charges and financial guarantees, the Company shall refund the deposit or deduct any unpaid amounts from the deposit and refund the difference, if any, to the Customer. The deposit shall no longer accrue interest upon the discontinuance of service.

The interest rate on deposits will be calculated pursuant to 66 Pa. C.S. § 1404 as amended from time to time.

GENERAL RULES AND REGULATIONS

3. Right-of-Way

An Applicant (and/or any existing Customer seeking additional service) requesting service from the Company, at the Applicant's/Customer's own expense, shall provide and grant to the Company a right-of-way, easement and/or permits satisfactory and acceptable to the Company, which by the Applicant/Customer has been cleared of trees and any other vegetation, as may be necessary for the erection and maintenance of the poles, wires and appurtenances, together with such tree and vegetation trimming and removal privileges as required per the Company's vegetation management policies to provide and maintain service.

Such right-of-way, easement and/or permits shall be granted to the Company without charge and shall permit the Company to permanently erect and maintain facilities over, under, through, across and/or along the property owned or controlled by the Applicant/Customer in order to provide electric service to the Applicant/Customer, provided, however, that no new right-of-way, easement and/or permits shall be required if a valid and continuing right-of-way, easement and/or permits with equivalent rights and privileges has already been granted to the Company by such Applicant/Customer or any predecessor in interest.

The Company shall not be obligated to provide any electric service to an Applicant/Customer until the Company has received and/or obtained satisfactory and acceptable to the Company rights-of-way, easements and/or permits from, but not limited to, the Applicant/Customer, applicable Government agencies, railroad owners or other property owners. Any right-of-way, easement or permit fees, either initial or recurring, or other charges in connection with rights-of-way, easements or permits for providing service to an Applicant/Customer, shall be paid for by the Applicant/Customer.

4. Extension of Company Facilities: System Upgrades

The standard service provided by the Company for delivery of electric energy to a Customer under this Tariff, regardless of delivery voltage, shall be from overhead Distribution Lines, except as noted in any Rate Schedule or other applicable provision of this Tariff. Subject to the requirements of this Tariff, the Company shall extend its Distribution and Transmission Lines to Applicants. Any request for electric service that requires the extension, removal, relocation or change of the Company's existing Distribution Lines shall be provided as set forth in this Rule. Applicants requesting a Line Extension shall, at the Company's discretion, execute the Company's Line Extension contract. Any Customer served by a Line Extension completed before the effective date of this Rule 4 shall be subject to the terms and conditions of its existing Line Extension contract and the Company's then-applicable Line Extension tariff, rules and regulations.

GENERAL RULES AND REGULATIONS

a. Line Extensions

(1) Non-Speculative Single Phase Line Extension

Company Obligations

As used in this Rule 4, a span of conductor is approximately equal to 180 feet. The Company shall construct, own and maintain all Line Extensions. The Company shall provide an Applicant, at no charge, up to three (3) spans of conductor, three (3) poles and related material on Public Right-of-Way for each Line Extension, including the Service Line. The Company shall provide an Applicant, at no charge, one (1) span of conductor and related material on Private Right-of-Way for each Line Extension, including the Service Line, to serve a Permanent Residential Customer. The number of spans provided to an Applicant/Customer at no charge shall be referred to in this Rule 4 as the span allowance. The Company's engineering layout shall be the sole basis used for determining the design of the Line Extension and/or Service Line. Any additional Line Extension and/or Service Line costs in excess of those costs assumed by the Company under this Tariff shall be borne by the Applicant/Customer.

The Company shall not commence construction of a Line Extension and/or Service Line until completion of all of the following:

(a) The Company's receipt and acceptance of an application for electric service.

(b) Execution by the Company and the Applicant/Customer of appropriate agreements for electric service and/or Line Extensions, and the payment by the Applicant/Customer of any and all associated costs or charges.

(c) The Applicant/Customer requesting the Line Extension and/or Service Line has furnished to the Company rights-of-way, easements and/or permits on, over, across, under and/or through the Applicant's/Customer's property that are necessary for the construction, maintenance and operation of the Line Extension and/or Service Line in accordance with Rule 3 of this Tariff and which are in form and substance satisfactory and acceptable to the Company.

The Company shall be under no obligation to construct the Line Extension and/or Service Line in the event it is unable to acquire all necessary rights-of-way, easements and/or permits and other consents from any parties other than the Applicant/Customer, in such form and substance satisfactory and acceptable to the Company.

GENERAL RULES AND REGULATIONS

Rule 4 – Extension of Company Facilities: System Upgrades (continued)

Applicant Obligations

Where the Non-Speculative Line Extension and/or Service Line exceeds the span allowance, the Applicant/Customer shall make a CIAC or Cash Advance to the Company equivalent to the Company's estimated Direct Labor Costs and Direct Material Costs and/or Contractor Costs for construction of that portion of the Line Extension and/or Service Line which is in excess of the span allowance. All Line Extension and/or Service Line costs in excess of the span allowance shall be charged to the Applicant/Customer.

In the event that an Applicant/Customer makes a Cash Advance to the Company for construction costs in excess of the span allowance, refund(s) shall be made to the initial Line Extension Applicant/Customer for each new Permanent Residential Customer added to the initial Line Extension. The refund(s) shall be calculated by the average cost per foot of the Line Extension in excess of the span allowance. Refunds shall be made only for Customer additions made within five (5) years from completion of the initial Line Extension and the sum of any refund(s) shall never exceed the initial Line Extension Applicant's / Customer's Cash Advance. Any balance from the Cash Advance remaining after five (5) years shall be retained by the Company. In lieu of paying a Cash Advance to the Company, the Applicant/Customer may elect to pay a CIAC to the Company.

If the Applicant/Customer requests, and Company approves, Line Extensions and/or Service Lines may be installed underground. Where a Customer requests underground service from overhead distribution facilities, the Company shall install such service upon receipt of a contribution, in the form of a CIAC, from the Customer equal to the amount the underground service costs exceed the overhead service costs. These costs will not be part of any Cash Advance or refund to a Cash Advance. The Company shall own, operate and maintain such underground facilities. In such case, the Applicant/Customer shall provide all necessary conduit, conduit installation, trenching, excavation, backfilling and grading in accordance with Company specifications, and shall bear all costs thereof.

GENERAL RULES AND REGULATIONS

Rule 4 – Extension of Company Facilities: System Upgrades (continued)

The Applicant/Customer shall perform or arrange and pay for all Company-directed rough grading in accordance with the Company's specifications for underground lines and facilities, as said specifications shall be modified by the Company from time to time.

The Applicant/Customer shall pay the cost of all tree trimming, brush clearance and related activity associated with the establishment of the right-of-way, easement or permit for the Line Extension and/or Service Line.

If Applicant/Customer requests any deviation from the Company's specifications, the Company may, in its sole and exclusive discretion, approve such request. Any Company-approved deviations from its construction practices shall be at the Applicant's/Customer's sole expense.

(2) Underground Electric Service in New Residential Developments

Company Obligations

All Distribution Lines and Service Lines installed within a new residential Development shall be installed underground; shall conform to the Company's construction standards, the specifications set forth in the National Electric Safety Code (NESC), and shall be owned and maintained by the Company. The Company or its agent shall install the necessary service-related facilities that may include the installation of padmount transformers. The Company shall, at the request of the Developer, install underground street lighting lines at the time of the original request for service to the Development or thereafter within the same Development. All street lighting shall be provided in accordance with this Tariff.

The Company shall require for Developments which qualify under this Rule 4a(2) (Underground Electric Service in New Residential Developments) and Rule 4a(3), (Speculative Single Phase and All Three-Phase Line Extensions and Service Lines) a CIAC or Cash Advance from the Applicant covering the Company's total estimated direct and indirect costs associated with the Line Extension to the tract of land being developed or within 100 feet of the boundary of Development. After the connection of Customers, external to the Development, to the Line Extension, a refund of the Cash Advance shall be made to the Applicant in accordance with Rule 4a(3) (Speculative Single Phase and All Three-Phase Line Extensions and Service Lines).

GENERAL RULES AND REGULATIONS

Rule 4 – Extension of Company Facilities: System Upgrades (continued)

The Company shall have the right to perform its own excavating and backfilling. If the Company elects to perform its own excavating and backfilling, there shall be no other charges to the Developer or to any other utility sharing the same trench.

Developer Obligations

A Developer shall pay the cost of providing the Company with a copy of the recorded development plot plan identifying property boundaries and with rights-of-way, easements and/or permits satisfactory and acceptable to the Company for occupancy by distribution, service and street lighting lines and related facilities.

The Developer or its agent shall provide all conduit, conduit installation, excavating, rough grading and backfilling required by the Company and shall meet the Company's specifications as they may be in effect from time to time. The Company upon request shall provide copies of the specifications to the Developer.

A Developer shall pay the Company for any necessary and additional costs incurred by the Company as a result of the following:

(a) Installation of underground facilities that deviate from the Company's underground construction standards and specifications if such deviation is requested by the Developer and is acceptable to the Company.

GENERAL RULES AND REGULATIONS

Rule 4 – Extension of Company Facilities: System Upgrades (continued)

(b) A change in the plot plan by the Developer for electric service after the Company has completed engineering for the project and/or has commenced installation of its facilities.

(c) Physical characteristics such as, but not limited to, oversized lots or lots with extreme setback.

A Subdivision is not required to have underground service. However, should the lot owner or owners in a subdivision desire underground service, such service shall be provided by the Company if such lot owner or owners, at their option, either comply with Rule 4a(1) (Non-Speculative Single Phase Line Extensions) and 4a(3) (Speculative Single Phase and All Three Phase Line Extensions and Service Lines).

If as a result of a Line Extension or any other request that results in an expansion of the Company's facilities, an increase in the Company's facilities, construction of a system upgrade or any other change to or the modification of the Company's electric system, the Applicant/Customer shall pay all costs for such work as specified in this Rule 4.

(3) Speculative Single Phase and All Three-Phase Line Extensions and Service Lines

When the Company is requested to increase capacity, expand facilities or construct Speculative Single Phase Line Extensions and/or Service Lines or Three-Phase Line Extensions and/or Service Lines, the Company shall determine from the circumstances of each case the nature and level of financing and/or guarantee of revenue required of the Applicant/Customer prior to construction or installation of Company facilities. The Company shall employ a five (5) year revenue guarantee in order to offset the initial construction costs. The five (5) year revenue guarantee includes five (5) years of forecasted distribution revenues less certain incremental delivery costs including, but not limited to, distribution operation and maintenance expenses, depreciation expenses, gross receipts taxes, state and federal income taxes, and a reasonable return component. The Company shall require the Applicant/Customer to make (i) a CIAC equivalent to the Company's total estimated costs associated with the construction of facilities necessary to render service in excess of the amount not covered by the revenue guarantee or (ii) a Cash Advance for the total construction costs to render service. The Company shall refund all or a portion of a Cash Advance previously provided by the Applicant in the event that the Company's revenue analysis for any newly connected Non-Residential Customer indicates that there are revenues in excess of the costs to provide service to that newly connected Non-Residential Customer, within five (5) years from the completion of the initial Line Extension.

GENERAL RULES AND REGULATIONS

Rule 4 – Extension of Company Facilities: System Upgrades (continued)

Where an application for an overhead Line Extension for a tract of land being developed or proposed to be developed, in whole or in part, for residential, commercial or industrial purposes, not covered by Rule 4a(2), (Underground Electric Service in New Residential Developments) is received from an entity that is not expected to be a Customer, the Company, prior to construction, shall require payment of a CIAC or a Cash Advance from the Applicant covering the Company's total estimated costs associated with the construction of said overhead extension (i) to the tract of land being developed and (ii) within the boundary of the tract of land necessary to serve prospective Customers in the tract.

After the connection of a Non-Residential Customer to the Line Extension, a refund of the Cash Advance shall be made to the Applicant in accordance with this Rule 4a(3) (Speculative Single Phase and All Three-Phase Line Extensions and Service Lines).

Applications for Speculative or Three-Phase Line Extensions and/or Service Lines shall be subject to the provisions of this Tariff.

In addition to the Line Extension costs described above, Customers shall also provide, install and pay for conduit, conduit installation, cable, metering conduit associated with their underground installation, including the Service Line, and such other costs specified in the Company's prevailing handbook.

The Applicant/Customer shall pay all costs as required for compliance with Rule 3.

b. Temporary Service

Temporary installations for Residential and Non-Residential Customers, requiring special service, meter or other work are made at the expense of the customer and shall provide electric service for a defined period, usually less than one (1) year ("Temporary Service"). Temporary Service, such as for construction purposes or exhibits of short duration, etc. shall be installed and removed at the Applicant's/Customer's expense. The Company shall provide the Temporary Service upon application from an Applicant/Customer. The Company shall provide the Temporary Service, provided that the Applicant/Customer reimburses the Company for all costs of installing and removing the service installation, including both material and labor, less the salvage recovered from all materials and equipment removed after

GENERAL RULES AND REGULATIONS

Rule 4 – Extension of Company Facilities: System Upgrades (continued)

termination of service. In all such cases, the Applicant/Customer shall make an advance payment to the Company sufficient to cover the estimated charges for installation and removal of the Temporary Service.

For Temporary Service for residential single-unit house construction where both the temporary Service Line and meter can be transferred to the completed building, the Temporary Service shall be provided by the Company upon the Applicant's/Customer's payment of the Company's estimated costs to provide this service.

c. Relocation of, or Modification to, Company Facilities; Service Interruptions

If as a result of a Line Extension or any other request that results in an expansion of the Company's facilities, an increase in the Company's facilities, construction of a system upgrade or any other change to or the modification of the Company's electric system, the Applicant/Customer shall pay all costs for such work as specified in this Rule 4.

Company Obligations

The Company shall remove, relocate or change the Company's facilities or temporarily interrupt service to a Customer's premises, upon the Customer's request, where such removal, relocation, change or interruption is acceptable to the Company.

The Company shall provide the Residential Customer with an estimate of the costs of removing, relocating, changing or interrupting the Customer's service, and the Residential Customer shall pay that amount to the Company prior to performing the work.

The Company shall bill the Residential Customer based upon the Contractor Costs and/or Direct Labor and Direct Material Costs associated with the removal, relocation or change of distribution facilities or interruption, less an amount equal to any maintenance expenses avoided as a result of such work.

The Company may, in its sole discretion, request a Non-Residential Customer or other person or entity to pay to the Company in advance the estimated cost to perform such work. The Company shall bill Non-Residential Customers or other person or entity the total cost of the work, including the total direct and indirect costs.

GENERAL RULES AND REGULATIONS

Rule 4 – Extension of Company Facilities: System Upgrades (continued)

After completion of the work, the Company shall bill or refund to the Non-Residential Customer or other person or entity, the difference between the estimated cost and the total direct and indirect cost of such work.

Customer Obligations

A Customer desiring the removal, relocation or change of Company facilities or interruption shall submit a request to the Company.

The Company may accept or reject said request in its sole and exclusive discretion. If the Company accepts said request, the Customer shall pay in advance the Company's total estimated cost for any Customer requested temporary interruption in the Customer's service due to construction, maintenance or other activities.

All Customers or other parties that request the removal, relocation or change of Company facilities shall furnish, without expense to the Company, satisfactory and acceptable to the Company rights-of-way, easements and/or permits for the construction, maintenance and operation of the relocated facilities.

Non-Residential Property Owner

A non-residential property owner shall not be relieved or excused from paying all costs associated with the relocation or modification of the Company's facilities or temporarily interrupt electric service to a Non-Residential Customer's property under this Rule 4(c) if such relocation or modification of Company facilities or temporary service interruption is the result of any order, rule, regulation or other direction to said property owner from any governmental or public authority.

GENERAL RULES AND REGULATIONS

5. Taxes on Applicant/Customer Advances

Any Applicant/Customer advance or other like amount received from an Applicant/Customer under this Tariff, under any contract executed under this Tariff or any other prior tariff shall constitute taxable income to the Company as defined by the Internal Revenue Service and shall be increased to include a payment by the Applicant/Customer equal to the applicable taxes. Such payment for taxes associated with such Applicant/Customer advance shall provide for the effect of current tax obligations offset by the present value of future tax deductions associated with the facility(ies) to be provided by the Company. The discount rate to be used for present value calculations shall be the Company's Allowance for Funds Used During Construction ("AFUDC") rate adjusted to a net of tax basis. Payments for taxes associated with Applicant/Customer advances shall not be discounted since any refunds of Applicant/Customer advances shall include a pro rata refund of amounts previously collected for applicable taxes.

6. Proof of Inspection

The Company will not connect or furnish electric service to or for a residential building or the completed construction, addition, alteration or repair of such a building or electric service upgrade unless the Applicant provides written proof to the Company that the building or structure has passed the inspections specified by and required under the Uniform Construction Code, 35 P.S. §§ 7210.101, *et seq.* ("*Construction Code*") and the Permit and Inspection Process for Residential Buildings established in the regulations implementing the *Construction Code* at 34 Pa. Code. §§ 403.61-.66.

For purposes of this Rule 6, the following definitions shall apply:

Addition – An extension or increase in the floor area or height of a building or structure, as defined by the *Construction Code*, 35 P.S. § 7210.103.

Alteration – Any construction or renovation to an existing structure other than repair or addition, as defined by the *Construction Code*, 35 P.S. § 7210.103.

Repair – The reconstruction or renewal of any part of an existing building for purpose of its maintenance, as defined by the *Construction Code*, 35 P.S. § 7210.103.

Residential building – Detached one-family and two-family dwellings and multiple single-family dwellings which are not more than three (3) stories in height with a separate means of egress which includes accessory structures, as defined by the *Construction Code*, 35 P.S. § 7210.103.

GENERAL RULES AND REGULATIONS

CHARACTERISTICS OF SERVICE

7. Wiring, Apparatus and Inspection

Company Obligations

The Company, owns, maintains, furnishes and installs the meters, unless otherwise allowed by the Commission. In addition, the Company shall install and maintain the transformers and Service Lines it deems necessary to provide for secondary service, unless specified otherwise in an applicable, valid and binding agreement. All equipment/facilities supplied by the Company shall remain its exclusive property and may be removed, in the Company's sole discretion, after termination of service for whatever cause.

The Company shall extend only one service lateral to a Customer's premises and install one (1) meter except where, in the Company's sole judgment, special conditions warrant the installation of additional facilities. Any type of service supplied by the Company to the same Customer at other points of delivery shall be metered and billed separately.

The Company shall repair and maintain any facilities/property it has installed on a Customer's premises. However, the Customer shall pay the full cost of inspection, repairs and/or replacement of all such facilities/property that may be damaged due to a Customer's negligence. No one shall break any seals or perform any work on any Company facilities including, but not limited to, meters without first receiving the Company's consent and approval.

GENERAL RULES AND REGULATIONS

Rule 7 – Wiring, Apparatus and Inspection (continued)

Applicant/Customer Obligations

Electric service installations shall be in accordance with the National Electrical Code, and all applicable local, state and federal codes, statutes and regulations, except as modified by the Company's then-applicable handbooks, booklets or other documents covering such installations, as they may be amended by the Company from time to time. A copy of the Company's requirements for electric service installations is available on the Company's website. The Company shall not be responsible for any injury or damage which may result from defects in wiring or devices on the customer's premises, provided, however, the Company may, without the assumption of any liability, connect a Customer's installation upon the filing of a proper application for inspection with the authority having jurisdiction, specifically reserving the right to disconnect said service if the said installation, on final inspection, proves defective and the customer, after reasonable notice, shall fail or refuse to rectify the said defects. If, on existing installations, there is reasonable doubt as to the safety of existing electrical equipment or wiring, the Company shall require, as a condition to furnishing service, that the service be inspected and approved by a qualified inspector in accordance with the National Electrical Code.

In the event that the Company is required by any state, federal or local governmental or public authority to place or relocate all or any portion of its facilities, including, but not limited to, mains, wires or services, poles or underground feeders, the Applicant/Customer shall, without cost or expense to the Company, change the location of the Applicant's/Customer's point of delivery to a point specified by the Company.

Upon the Company designating a point of delivery at which its service line will terminate, the Applicant/Customer shall provide, at its sole cost and expense, a place suitable to the Company for the installation of metering and all other electric facilities needed for the supply of electric energy by the Company or an EGS. Meters shall be located on the outside wall of a building as near as possible to the service entrance or under certain circumstances, when approved by the Company, inside of a building.

The Company may refuse to connect with any Applicant's/Customer's installation or to make additions or alterations to the Company's service connection when such installation is not in accordance with the National Electrical Code, and all applicable local, state and federal codes, statutes and regulations, and where a certificate approving such installations, additions or alterations has not been issued by (i) an electrical inspection authority contained on a list of such authorities maintained by the Pennsylvania Department of Labor and Industry or (ii) any city or county inspection entity having exclusive authority to make electrical inspections in that area.

GENERAL RULES AND REGULATIONS

Rule 7 – Wiring, Apparatus and Inspection (continued)

When a Customer's facilities or use of equipment having operating characteristics that adversely affects or has the potential to adversely affect, in the Company's sole judgment, the Company's electric system, the Customer shall take corrective action at its sole expense as may be directed by the Company. Unless corrective action is taken, the Company is under no obligation to serve or to continue to serve such Customers.

Each Applicant/Customer shall provide to the Company such service information described in Rule 1 of this Tariff. The Applicant/Customer shall be responsible and liable to the Company for any damages resulting from the Customer's failure to provide such service information.

The Company will require the customer to maintain a Power Factor in the range of 85% to 100% for secondary, primary and subtransmission service and 90% to 100% for transmission service, coincident with the customers maximum monthly peak demand and to provide, at the Customer's expense, any corrective equipment necessary in order to do so. The Company may inspect the Customer's installed equipment and/or place instruments on the premises of the Customer in order to determine compliance with this requirement, as deemed appropriate by the Company. The Company may charge the Customer the Company's installation cost incurred for corrective devices necessary for compliance with this provision. The Company is under no obligation to serve, or to continue to serve, a Customer who does not maintain a Power Factor consistent with the parameters set forth in this provision.

8. Metering

Company Obligations

The Company owns, maintains, installs and operates a variety of meters, and related equipment designed to measure and record Customers' consumption and usage of all services provided under this Tariff. The Company may, in its sole and exclusive discretion, install such meters and related equipment it deems reasonable and appropriate to provide service to Customers under this Tariff. The Company may, in its sole and exclusive discretion, install such special metering equipment as may be requested by a Customer, subject to the Customer paying all of the Company's incremental material, labor, overheads and administrative and general expenses relating to such facilities. Where additional metering services and the associated costs for the additional metering services are contained within this Tariff, those costs shall also be applicable.

GENERAL RULES AND REGULATIONS

Rule 8 – Metering (continued)

The Company shall conduct inspections and tests of its meters in accordance with prudent electric practices and as otherwise prescribed by all applicable Commission regulations.

Customer Obligations

The Customer shall install metering equipment, other than meters, in accordance with the requirements specified by the Company as amended from time to time.

Any Customer requesting a test of its meter(s) shall pay such fee(s) as established or approved from time to time by the Commission. If a tested meter does not meet Commission accuracy standards, the fee shall be returned to the Customer and the meter shall be repaired or replaced.

If requested by a Customer, or Customer's designated agent, the Company may, in its sole discretion, elect to supply near real time communication of raw data directly from the meter in a format not provided from the Company's standard metering equipment. All costs for providing near real time communication of raw data directly from the meter in a format not provided by the Company's standard metering equipment shall be paid by the Customer. If a Customer's, or Customer's designated agent subsequent consumption of kilowatts, kilovars and/or kilowatt-hours increases as a result of interruptions in the supply of raw data in any format due to, among other things, power outages or equipment failure which prevents the supply of raw data in any format, the Company shall not be responsible or liable, in damages or otherwise, for resulting increases in the Customer's bill.

If requested by a Customer, the Company may, in its sole discretion, elect to provide metering to a service location other than what is presently installed or otherwise proposed to be installed by the Company at that location. All costs for special metering facilities provided by the Company, including, but not limited to, all material, labor, overheads and administrative and general expenses, shall be billed to and paid by the Customer.

If requested by a Customer, the Company will install a communicating point-to-point ("PTP") smart meter at a Customer's metered service location prior to the Company's system-wide deployment of smart meters. Prior to installation, the Customer shall pay $346.95 for a single phase PTP smart meter and $457.82 for a three phase PTP smart meter. Costs for Customer requests for a PTP smart meter at service locations without a functional public cellular network will be determined on a case by case basis and must be paid by the Customer prior to the commencement of Company work. Costs are charged individually for each metering point at each service location, and include the estimated incremental costs associated with a PTP smart meter, a communication cellular card, and connection fees. The Customer shall pay $36.00 for requests to remove a PTP smart meter prior to the Company's system-wide deployment of smart meters. All other costs and cost reconciliations associated with Customer requests for a PTP smart meter shall be collected from the associated customer class in the Smart Meter Technologies Charge Rider. The Customer is responsible for any repairs to

GENERAL RULES AND REGULATIONS

Rule 8 – Metering (continued)

Customer-owned equipment, such as meter socket repairs, prior to the installation of a PTP smart meter. The Company shall maintain ownership of all PTP smart meters.

The Company owns and installs the appropriate metering, along with an available metering communication technology, necessary to bill the Customer according to tariff provisions. Where the selected metering utilizes a communication technology not enabled by smart metering, the Customer is responsible for providing the communication link per the Company's specifications or shall pay the Company any and all expenses for providing communications.

GENERAL RULES AND REGULATIONS

BILLING CONSIDERATIONS

9. Access to Customer Premises

The Company shall have the right to construct, operate and/or maintain any and all facilities it deems necessary to render electric service (including, but not limited to, billing and meter reading) to the Customer upon, over, across and/or under lands owned or controlled by the Customer. Each Customer shall grant the Company's employees or agents access to their premises at all reasonable times for any and all purposes relating to the supply of electric energy including, but not limited to, reading meters, testing or inspecting the Customer's wiring and connected load, repairing, removing or exchanging any or all equipment belonging to the Company, and for the purpose of removing the Company's property and/or facilities upon the termination of any applicable contract or the discontinuance of service from whatever cause.

10. Meter Reading and Rendering of Bills

a. Meter Reading

(1) Meters shall be read and bills for service shall be rendered monthly by the Company based upon its meter reading and billing schedule, except as otherwise provided in this Tariff. The Company reserves the right to read meters in all or any part of its service area on bi-monthly or quarterly schedules, except as provided for under Chapter 56 of the Commission's regulations and to render standard bills for the recorded use of service based upon the time interval between meter readings. In addition, the Company may elect, in its sole discretion, to read meters in all or any part of its service area less frequently than on a quarterly schedule and to render standard bills for the recorded use of service based upon the time interval between meter readings for (i) General Service Customers with constant use patterns such as, but not limited to, billboards, traffic signals, and pumps, and (ii) Seasonal Customers such as, but not limited to, camps and cottages.

GENERAL RULES AND REGULATIONS

Rule 10 – Meter Reading and Rendering of Bills (continued)

(2) At a Customer's request, not more than one (1) time per calendar year, the Company shall provide at no cost to the Customer, the Customer's historical billing data for the most recent twelve (12) months for which such data is available. If a Customer requests billing data (i) for a period earlier than the most recent twelve (12) months for which the data is available or (ii) in greater detail than normally maintained by the Company and provided to Customers, the Company may, in its sole discretion, provide such additional data to the Customer, reserving the right to charge Customers an additional amount for historical billing beyond the most recent twelve (12) months to offset the costs of providing the service.

b. Rendering of Bills

(1) Estimated Bills

At its option, when meters are read on other than a monthly schedule, the Company may render estimated bills to Customers on a monthly basis for the periods when meter readings are not obtained, and such bills shall be due and payable by each Customer upon presentation by the Company, subject to the Company's standard payment terms.

Upon request, the Company shall provide to a Customer a card upon which the Customer can mark its meter readings for any interim month, mail it to the Company, and receive a bill for the month's service.

When interim monthly bills are not rendered by the Company, a Customer, at its option, may voluntarily pay the Company its own estimate of an interim monthly bill, and such payment shall be shown by the Company as a credit on the next standard bill rendered to that Customer.

In the event the Company is unable to gain access to the meter location to obtain readings, it may, at its option, estimate the amount of electric service supplied based upon the Customer's past usage or, if no prior Customer usage is available, the past usage at the service location, and render an appropriate bill, which shall be paid in accordance with the Company's payment terms specified in this Tariff. Any bills covering subsequent meter readings shall reflect any adjustment due to under- or over-estimation, or any unusual circumstances known to have affected the quantity of service used by the Customer or consumed at the premises.

GENERAL RULES AND REGULATIONS

Rule 10 – Meter Reading and Rendering of Bills (continued)

The Company shall bill a Customer for energy used when, during any current or prior periods, a Customer's meter fails to correctly register the amount of electricity consumed. The amount of the bill or adjustments to prior bills shall be estimated by the Company, giving due consideration to the amount of use for the periods preceding and subsequent to such defective registration(s) by the meter.

(2) Summary Billing

Upon a Customer's request and the Company's approval, a Customer with multiple accounts may receive Summary Billing. Summary Billing may be permitted by the Company in those cases where read and due dates of the multiple accounts allow for Summary Billing without adversely affecting the timely payment of bills and where Summary Billing does not have an adverse financial impact on the Company. The Company may, in its sole discretion, charge Customers an additional amount for Summary Billing to offset any actual or potential adverse financial impact on the Company. A single due date for accounts that are summary billed shall be established by the Company and provided to the Customer. Summary Billing shall not commence unless and until the Customer agrees to the due date established for such Summary Billing.

GENERAL RULES AND REGULATIONS

Rule 10 – Meter Reading and Rendering of Bills (continued)

(3) Special Billing

The Company shall consider all requests from Customers to deviate from the Company's standard billing practices and procedures ("Special Billing"), including those described in this Tariff. The Company may, in its sole discretion, agree to provide Special Billing to a Customer, subject to such terms and conditions as the Company may prescribe including, but not limited to, payment by the Customer of all costs associated with the Company providing such Special Billing.

(4) Equal Payment Plan

The Equal Payment Plan (EPP) for Residential Customers is designed to make monthly payments consistent throughout an entire year, leveling out seasonal highs and lows. At the request of a Delivery Service Residential Customer, the Company shall estimate the Customer's Delivery Service Charges for a twelve (12) month period. The EPP is calculated by adding the total of the dollars invoiced for the previous 355 days. This amount is divided by the number of days in the twelve-month invoice history, the result of which is then multiplied by 31. These amounts are reviewed every three months. Customer's EPP payment amounts are adjusted if the actual cost of service is lower or higher than the monthly estimated amount where: the percent difference is greater than or equal to 25% OR the dollar difference is greater than or equal to $10. The review process occurs automatically during the invoice process in the appropriate month. If the review results in a change of the EPP amount, the information will be placed on the invoice advising the customer of the new amount and the next month's invoice will reflect the new amount. During the twelfth month, the anniversary bill will be presented. An information box will be placed on the invoice advising the Customer of the new amount. The Customer is responsible for the current EPP charge plus the difference in the EPP plan. A resulting reconciliation amount exceeding One-Hundred Dollars ($100.00) will be amortized consistent with applicable regulations upon request of the Customer. If a credit exists at the true-up month, it will be cleared against the current month amount. If a Customer fails to pay an outstanding bill by the time its next monthly bill is rendered, the Company may, in its sole discretion, terminate that Customer's Equal Payment Plan arrangements.

The Company shall make available the Equal Payment Plan for Default Service Charges and Delivery Service Charges for Federal Department of Housing and Urban Development ("HUD") financed housing during the time that such housing is either owned by HUD or subject to a first mortgage held or guaranteed by that agency which is (i) master metered and (ii) has electrically heated multi-family dwelling units. All provisions specified in this Rule 10b(4) for Equal Payment Plans for Default Service and Delivery Service Residential Customers shall apply to such housing.

GENERAL RULES AND REGULATIONS

Rule 10 – Meter Reading and Rendering of Bills (continued)

(5) Combined Billing

Residential Customers with both metered Residential Service and private Outdoor Lighting Service may request to receive Combined Billing from the Company for the two services.

Combined Billing for Non-Residential Customers shall be restricted as stated in the applicable provisions of this Tariff.

(6) Consolidated Billing

A Delivery Service Customer that has contracted with an EGS shall receive Consolidated Billing from the Company unless the Customer requests bills only for Delivery Service Charges.

(7) Minimum Charge

Each Rate Schedule of this Tariff applicable to Residential and Non-Residential Customers shall specify the Minimum Charge applicable to all service and Customers taking service under such Rate Schedule.

(8) Transformer Losses Adjustment

The Company may, at its option, meter its service at Primary Voltage of Company-owned transformers or at the Secondary Voltage of Customer-owned transformers. In such cases, the applicable demand and energy charges shall be increased (in the case of metering at Secondary Voltage) or decreased (in the case of metering at Primary Voltage) by two and one-half percent (2.5%) to compensate for transformer losses.

GENERAL RULES AND REGULATIONS

Rule 10 – Meter Reading and Rendering of Bills (continued)

(9) Power Factor/ Kilovar Billing

Billing for Power Factor or Kilovars, whichever is applicable, shall be in accordance with the Customer's applicable Rate Schedule or other provisions of this Tariff. The Power Factor used for billing purposes shall be rounded to the next highest whole percent, unless otherwise stated in the Customer's applicable Rate Schedule or other provisions of this Tariff.

(10) Billing for Vandalism, Theft or Deception

In the event there is any evidence that the Company's meters or other equipment on the Customer's premises have been tampered or interfered with by any means whatsoever, resulting in improper or non-registration of service supplied, the Customer being supplied through such equipment shall pay to the Company the amount the Company estimates is due for service used but not registered on the Company's meter, and the cost of any repairs or replacements, inspections and investigations relating thereto including, but not limited to, all administrative expenses associated with the investigation(s) (e.g., Legal, Accounting/Billing, etc.). Under these circumstances, the Company may at its option terminate its service immediately and/or require the Customer to pay all costs correcting any and all unauthorized conditions at the premises. In the event service has been terminated under these circumstances it shall not be restored to the Customer's premises until: (i) the Customer has a certificate of compliance with the provisions of the National Electric Code and the regulations of the National Fire Protection Association has been issued by the municipal inspection bureau or by any Company-accepted inspection agency, (ii) the Customer has complied with all of the Company's requirements and (iii) the Customer pays the Company a reconnection fee and deposit.

In the event there is any evidence that a Customer knowingly and willfully obtained service for itself or for another by creating or reinforcing a false impression, statement or representation and fails to correct the same, the Company shall immediately correct the account information in question and issue an adjustment for all current or previous amounts. The Customer shall be required to show proof of identity and sign an agreement for payment of all electric service received, plus any and all costs and administrative expenses associated with any investigation(s) (i.e., Legal, Accounts/Billing, etc.) which shall be added to their account. The Customer shall have three (3) business days in which to provide proof of identity. The Company may, in its sole discretion, terminate a Customer's electric service if the Customer fails to provide such proof of identity within the aforementioned time period.

GENERAL RULES AND REGULATIONS

Rule 10 – Meter Reading and Rendering of Bills (continued)

(11) Billing Errors

When the Company provides billing for Competitive Energy Supply on behalf of an EGS, the Company shall not be responsible for billing errors resulting from incorrect price information received from an EGS.

11. Payment of Bills

Except as otherwise provided in the Tariff, bills for service shall be rendered monthly based upon the Company's read and billing schedule and are due and payable by the Customer to the Company upon presentation by the Company for service furnished during the preceding period.

Remittances mailed by the Customer for the amount(s) due shall be accepted by the Company as tendered within the period to avoid late payment charges if such payment is received by the Company no more than five (5) days after the due date of the bill.

These provisions shall also apply, as appropriate, to Customers receiving Consolidated Billing. However, it is limited to the Basic services portion of the consolidated bill. Basic services shall have the meaning as defined in 52 Pa. Code § 54.2. The applicability of this section is also subject to consumer protections ordered by the Commission.

a. Due Dates

For Residential Customers, bills are due and payable to the Company on or before twenty (20) days from the date of mailing of the bill to said Customer. Non-Residential Customers' bills are due and payable to the Company on or before fifteen (15) days from the date the bill is mailed to said Customer.

Upon the request of a Residential Customer sixty (60) years of age or older or a Residential Customer receiving Social Security or an equivalent monthly pension payment, the Company may extend the due date of such Customer's bill from twenty (20) days to thirty (30) days upon such verification of the Customer's eligibility for payments as the Company deems reasonably necessary.

The following shall be allowed thirty (30) days for payment of their bills at net rates (i) local governmental bodies (including school districts), (ii) the Commonwealth of Pennsylvania, and (iii) agencies of the Federal Government.

GENERAL RULES AND REGULATIONS

Rule 11 – Payment of Bills (continued)

A Customer's failure to receive a bill shall not be construed or deemed, under any circumstances, to be a waiver of any of the provisions of this Tariff. A Customer's bill shall be overdue when not paid on or before the due date indicated in the bill.

b. Late Payment Charges

Late payment charges shall be applied to Default Service Charges, EGS charges that are subject to the Company's POR and Delivery Service Charges. The Company will apply late payment charges to EGS charges that are not subject to the Company's POR at the EGS's request when it is performing billing services for the EGS.

A Residential Customer's overdue bill shall be subject to a late payment charge of one and one-half percent (1.5%) interest per month on the full unpaid and overdue balance of the bill. A Non-Residential Customer's overdue bill shall be subject to a late payment charge of two percent (2.0%) interest per month on the full unpaid and overdue balance of the bill. Interest charges shall be calculated by the Company on the overdue portions of the bill and shall not be charged against any sum that falls due during a current billing period.

c. Allocation of Payments

All payments made by or on behalf of a Customer shall be applied to a Customer's account in accordance with the Commission's payment posting rules and applicable Regulations including the Company's Electric Generation Supplier Coordination Tariff on file with the Commission.

d. Delinquent Accounts

A Customer's account is delinquent when not paid in full by the due date stated on the bill or otherwise agreed upon by the Customer and the Company. The Company shall pursue collections of outstanding residential delinquent account balances in accordance with applicable law and Commission regulations. Termination of service will occur only for non-payment of undisputed delinquent accounts associated with the Company's regulated charges, which shall include EGS charges subject to the Company's POR.

The Company will have the ability to terminate service to a Customer for the Customer's non-payment of EGS Basic Electric Supply charges incurred after January 1, 2011 in the same manner and to the same extent that the Company could terminate service to such a Customer for non-payment of EDC charges. Residential Customer's termination will be subject to the consumer protections included in Chapter 14 of the Public Utility Code, Chapters 55 and 56 of the Commission's regulations, 52 Pa. Code §§ 55.1 and 56.1 et. seq., and/or other applicable regulations as may change from time to time. The POR is only available as long as the Company is able to terminate service to Customers under Chapter 14 of the Public Utility Code and Chapters 55 and 56 of the Commission's regulations, 52 Pa. Code §§ 55.1 and 56.1 et. seq., and/or other applicable regulations as may change from time to time.

GENERAL RULES AND REGULATIONS

Rule 11 – Payment of Bills (continued)

In the case of non-payment of a Customer's delinquent bill applicable to the Company's charges, the Company may, in its sole discretion, terminate its electric service and remove its equipment in accordance with applicable law and Commission regulations. The Company shall condition restoration of service on payment of EGS charges subject to the Company's POR.

A Residential Customer who has elected to receive Combined Billing for metered Residential Service and Outdoor Lighting Service shall be subject to 52 Pa. Code, Chapter 56 of the Commission's regulations and be treated as a single residential account.

e. Winter Termination – Determining Income Eligibility for Winter Termination

To determine if a Customer exceeds the 250% federal poverty level threshold, the Company will utilize financial information provided by the Customer. The Company may elect to send to the Customer an income verification form for completion and return.

12. Administrative Charges

a. Service Charges

Every Applicant or Customer, new or succession, who has its Delivery Service initiated or reconnected shall pay a service charge of Twelve Dollars and Fifty Cents ($12.50) to the Company.

b. Dishonorable Tender Charges

If a check or electronic transfer of funds received by the Company in payment of a Customer's account is returned unpaid or denied to the Company by the Customer's bank, a Fifteen Dollar ($15.00) charge for the returned check shall be added by the Company to the Customer's account and the Customer shall pay this amount to the Company in addition to all other applicable charges. A repeated cancellation by the Customer of electronic transfers or payments in the same twelve month period may, in the Company's discretion, result in revocation of rights to pay by electronic means.

c. Reconnect Charges

A Residential Customer who requests a disconnection and reconnection of service at the same location within a twelve (12) month period shall pay the Company a reconnect charge equivalent to the monthly minimum charge stated in the Customer's applicable Rate Schedule or other Tariff provision multiplied by the number of months between the disconnect and reconnect period, or the minimum reconnect charge stated in this Rule 12c, whichever is greater.

GENERAL RULES AND REGULATIONS

Rule 12 - Administrative Charges (continued)

Every Residential Customer that requests a connection or a reconnection shall pay the Company a fee of Thirty-Six Dollars ($36.00).

Every Non-Residential Customer shall pay the Company a reconnection fee/charge that is the higher of (i) the Residential Customer reconnect fees/charges specified in this Rule 12c or (ii) the Company's actual cost for reconnection of that particular Non-Residential Customer.

13. Determination of Demand

A Customer's active and/or reactive demand (if applicable) shall be measured by a meter acceptable to the Company registering the rate of use of energy and reactive energy during a specified time interval during each billing period. If, for any reason, the Company is unable to supply the Customer kilowatt or kilovar meters, the Company may, at its option, determine the Customer's use by means of periodic kilowatt or kilovar tests or estimates.

INDIVIDUALIZED SERVICES

14. Individualized Contracts

The Company, at its sole discretion, may enter into an Individualized Contract with a Non-Residential Applicant/Customer. If requested by the Company, the Non-Residential Applicant/Customer shall provide to the Company, or at the Company's option, to an agent representing the Company, all information and records necessary to evaluate the request for an Individualized Contract. All costs billed by the agent to the Company shall be paid by and the responsibility of the Non-Residential Applicant/Customer.

GENERAL RULES AND REGULATIONS

Rule 14 – Individualized Contracts (continued)

The terms and conditions of Delivery Service in each Individualized Contract shall be as mutually agreed upon between the Company and the Non-Residential Applicant/Customer. When fully executed, the Company may, in its sole discretion, request Commission approval thereof. The effective date of an Individualized Contract, filed with the Commission, shall be no less than ninety (90) days after the date of its filing with the Commission. The rates for each Individualized Contract shall be (i) established mutually by the Company and Non-Residential Applicant/Customer on a case by case basis and (ii) designed to recover at a minimum all of the Company's appropriate incremental costs of the service and a contribution to its fixed costs.

The Individualized Contract shall contain all service terms and conditions and the rates and charges to be paid for service rendered.

The Company may require the Non-Residential Applicant/Customer to provide the Company or its agent with a recent energy audit of the Non-Residential Applicant's/Customer's facilities and a list of all energy conservation and load management activities which have occurred in the past five (5) years, along with a list of all ongoing energy conservation and load management activities or proposed activities.

The Individualized Contract may be terminated by the Company if an eligible Non-Residential Customer's bills are not paid when due as specified in this Tariff.

In the event that any Individualized Contract is terminated by the Company or Non-Residential Applicant/Customer under the conditions specified in the contract, the Non-Residential Applicant/Customer shall subsequently be eligible for service under the standard Tariff Rate Schedule for which it qualifies.

The Company may modify or discontinue the provisions of this Rule 14 at any time, subject to any orders of the Commission. Unless otherwise ordered by the Commission, any Individualized Contracts in effect prior to any such modification or discontinuance of this Rule 14 shall remain in effect under the term and conditions specified in the applicable contract.

GENERAL RULES AND REGULATIONS

Rule 14 – Individualized Contracts (continued)

All applicable riders are chargeable to a Customer with an Individualized Contract and will be calculated and billed to the Customer using the same formula that would otherwise be applied under the Customer's applicable standard tariff rate schedule.

15. Company Facilities, Services and Products

The Company may furnish, at its sole discretion and upon an Applicant's/Customer's request, special, substitute, emergency repairs or additional facilities, services or products to such Applicant/Customer. When the Company provides facilities, services or products not normally supplied to an Applicant/Customer, or when the estimated or actual cost of such individualized, substitute, or additional facilities, services or products exceeds the estimated costs of the standard facilities, services or products that normally would be supplied by the Company without special charge, the Company may require the Applicant/Customer to enter into special agreement(s) ("Specialized Contracts") and may establish minimum charges and facilities charges. The Company may offer to Customers additional services or products that may be applicable to more than one Customer. At a minimum, charges under this Rule 15 shall be established by the Company on a case by case basis and shall be sufficient to recover all of its appropriate incremental costs of the service and a contribution to its fixed costs.

The Company may modify or discontinue the provisions of this Rule 15 at any time, subject to any Commission orders. Unless otherwise ordered by the Commission, any Specialized Contracts in effect prior to any such modification or discontinuance of this Rule 15 shall remain in effect under the term and conditions specified in the contract.

GENERAL RULES AND REGULATIONS

16. Auxiliary Power Sources and Readiness to Serve

Service to a Customer, any part of whose electric requirements are provided by other than Company-owned facilities, and where the Company supply can be substituted for that of the Customer, will be supplied only under the provisions of this rule.

The maximum demand in kilowatt and power factor which the Company is obligated to supply shall be determined by agreement between Customer and Company.

In case the maximum demand in kilovolt-amperes which the Company is obligated to supply is less than the Customer's maximum demand as estimated by the Company, the Company may require the Customer to limit his demand to the load which the Company is obligated to supply by means of a load limiter to be furnished, installed, and maintained by the Customer, approved, set, and sealed by the Company.

The Customer shall not at any instant operate any source of supply in parallel with the Company's service without written permission from the Company.

Monthly billing will be under the provisions of the rates in conjunction with which this rule is employed.

The Customer shall reimburse the Company for all loss or damage sustained by the Company as a result of the Customer's use of the Company's service under the provisions of this rule.

17. Interconnection, Safety & Reliability Requirements

In order to assure the integrity and safe operation of the Company’s system and to permit the continuation of reliable service to other Customers, the following requirements and standards apply to all types of Generating Facilities, including customer owned generation, desiring to interconnect with the Company’s system.

GENERAL RULES AND REGULATIONS

Rule 17 – Interconnection, Safety & Reliability Requirements (continued)

All generation operations shall be performed in a safe, reasonable and competent manner in accordance with prudent electric practices in order to, among other things, preserve and protect the Company's electric system.

All Generating Facilities shall submit a written application to the Company for acceptance of interconnected operation of their facilities with the Company's system prior to engaging in such interconnected operations. The Company may require, among other things, the following as part of any application submitted by an Applicant/Customer for service under this Rule 17:

a. Plans, specifications and location of the proposed installation.

b. Single line diagrams and details of the proposed protection schemes.

c. Instruction manuals for all protective components.

d. Component specifications and internal wiring diagrams of protective components, if not provided in instruction manuals.

e. Generator data required to analyze fault contributions and load current flows including, but not limited to, equivalent impedances, time constants and harmonic distortions.

f. The rating of all protective equipment if not provided in instruction manuals.

g. All such other information that may be required by the Company.

Paralleling Customer generation with the Company's system shall be permitted only upon the written consent of the Company.

GENERAL RULES AND REGULATIONS

EMERGENCY CONDITIONS

18. Load Control

Whenever the demands for electric power on all or part of the Company's system exceed or threaten to exceed the capacity then actually and lawfully available to supply such demands, or whenever system instability or cascading outages could result from actual or expected transmission overloads or other contingencies, or whenever such conditions exist in the system of another public utility or PJM control area with which the Company's system is interconnected and cause a reduction in the capacity available to the Company from that source or threaten the integrity of the Company's system or when communicated by PJM per established policies and standards, a load emergency situation exists. In such case(s), the Company shall take such reasonable steps as the time available permits or as directed by PJM to bring the demands within the then-available capacity or otherwise control load. Such steps shall include, but shall not be limited to, reduction or interruption of service to one or more Customers, in accordance with the Company's procedures for controlling load.

19. Energy Conservation

Whenever events occur which actually result or, in the judgment of the Company or PJM, threaten to result in a restriction of the fuel supplies available to generators that supply energy to the PJM markets, such that the amount of electric energy which the Company is able to supply is or shall be adversely affected, an emergency energy conservation situation exists.

In the event of an emergency energy conservation situation, the Company shall take such reasonable measures as it believes necessary and proper to conserve available fuel supplies. Such measures may include, but shall not be limited to, reduction, interruption, or suspension of electric service to one or more of its Customers or classes of Customers in accordance with the Company's procedures for emergency energy conservation.

GENERAL RULES AND REGULATIONS

MISCELLANEOUS PROVISIONS

20. Discontinuance

The Company may, at its sole option, terminate any service provided under this Tariff and remove its equipment on (i) required notice in case of a Customer's non-payment of a delinquent bill or a violation of the provisions of this Tariff or (ii), without notice, in situations which endanger or may endanger the safety of any person or property or may prove harmful to the Company's energy delivery system. Failure by the Company at any time to exercise its rights shall not be deemed a waiver thereof. Termination of service will occur for non-payment of undisputed delinquent bills associated with the Company's regulated charges, which shall include EGS charges subject to the Company's POR.

For Residential Customers, the Company may terminate service under any of the following circumstances (i) unauthorized use of the service delivered on or about the affected dwelling (ii) fraud or material misrepresentation of the Customer's identity for purpose of obtaining service (iii) tampering with the Company's meters or other equipment (iv) violating the Tariff provisions in a manner that endangers the safety of a person or the integrity or operation of the Company's facilities.

Where a Residential Customer has elected to receive Combined Billing for metered Residential Service and Outdoor Lighting Service, both services shall be subject to the Commission's Standards and Billing Practices for Residential Utility Service, 52 Pa. Code, Chapter 56, as a single residential account for all purposes including, but not limited to, discontinuance of service.

The Company may discontinue the supply of service to a particular Customer to the extent (and as may be) required to comply with any governmental rule, regulation, statute, order or directive. Verbal or written orders of police, fire, public health or similar officers, given in the performance of their duties, shall also permit the discontinuance of service under this Rule 20.

The Company may at any other time suspend the supply of electrical energy to any Customer for the purpose of making repairs, changes or improvements on any part of its system. When such suspension is planned in advance, prior notice of the cause and expected duration of the suspension shall be given to the extent practicable to Customers who may be affected.

GENERAL RULES AND REGULATIONS

21. Service Continuity: Limitation on Liability for Service Interruptions and Variations

The Customer, by accepting service from the Company, assumes responsibility for the safety and adequacy of the wiring and equipment installed by the Customer. The Customer agrees to indemnify and save harmless the Company from any liability which may arise as a result of the presence or use of the Company's electric service or property, defects in wiring or devices on the Customer's premises, or the Customer's failure to comply with the National Electrical Code.

The Company does not guarantee a continuous, uninterrupted, or regular supply of electric service. The Company may, without liability, interrupt or limit the supply of electric service for the purpose of making repairs, changes, or improvements in any part of its system for the general good of the service or the safety of the public or for the purpose of preventing or limiting any actual or threatened instability or disturbance of the system. The Company shall not be liable for any damages due to accident, strike, storm, lightning, riot, fire, flood, legal process, state or municipal interference, or any other cause beyond the Company's control.

In all other circumstances, unless caused by the willful and/or wanton misconduct of the Company, the liability of the Company to Customers or third parties for all injuries and damages, direct or consequential, including damage to computers and other electronic equipment and appliances, or loss of business, profit or production caused by variations or interruptions in electric supply, high or low voltage, spikes, surges, single phasing, phase failure or reversal, stray voltage, neutral to earth voltage, equipment failure or malfunction, response time to electric outages or emergencies, or the non-functioning or malfunctioning of street lights or traffic control signals and devices shall be limited to Five Hundred Dollars ($500) for residential customers and Two Thousand Dollars ($2,000) for commercial and industrial customers. In no case shall the Company's aggregate liability for multiple claims arising from a single alleged negligent act, incident, event, or omission exceed Two Hundred Thousand ($200,000). The Company's actions that are in conformance with electric system design, the National Electrical Safety Code, or electric industry operation practices shall be conclusively deemed not to be negligent. A variety of protective devices and alternate power supply equipment that may prevent or limit such damages are available. Due to the sensitive nature of computers and other electronically controlled equipment, the Customer, especially three-phase Customers, should provide protection against variations in supply.

GENERAL RULES AND REGULATIONS

Rule 21 – Service Continuity: Limitation on Liability for Service (continued)

To the extent applicable under the Uniform Commercial Code or on any theory of contract or products liability, the Company disclaims and shall not be liable to any Customer or third party for any claims involving and including, but not limited to, strict products liability, breach of contract, and breach of actual or implied warranties of merchantability or fitness for an intended purpose.

If the Company becomes liable under Section 2806(g) or 2809(c) of the Public Utility Code, 66 Pa. C.S. §§ 2806(g) and 2809(f), for Pennsylvania state taxes not paid by an Electric Generation Supplier (EGS), the non-compliant EGS shall indemnify the Company for the amount of additional state tax liability imposed upon the Company by the Pennsylvania Department of Revenue due to the failure of the EGS to pay or remit to the Commonwealth the tax imposed on its gross receipts under Section 1101 of the Tax Report Code of 1971 or Chapter 28 of Title 66.

22. Transfer of Electric Generation Supplier

Company shall change Customer’s electric supplier only upon receipt of electronic notification from the chosen electric supplier in accordance with the Pa P.U.C. Rules and Regulations as described in the Final Orders on Standards for Electronic Data Transfer and Exchange Electric Distribution Companies and Electric Generation Suppliers, Docket No. M-00960890F0015 and on Establishing Standards for Changing a Customer's Electric Supplier, Docket No. L-00970121. Changes in Customer's electric Supplier shall only be effective with Customer's normal meter reading date, regardless of whether the meter reading is actual or estimated.

RATE SCHEDULES

RATE RS
RESIDENTIAL SERVICE RATE

AVAILABILITY:

This Rate is available to Residential Customers using the Company's standard, single phase service through a single meter including not more than 2,000 watts of non-residential connected load served through the same meter.

All of the following general monthly charges are applicable to Delivery Service Customers:

GENERAL MONTHLY CHARGES:

Distribution Charge

$13.29 per month (Customer Charge), plus
4.103 cents per kWh for all kWh

RIDERS

Bills rendered under this schedule are subject to the following applicable Rider Charges:

Rider A – Tax Adjustment Surcharge
Rider B – Storm Damage Charge
Rider C – Universal Service Cost Rider
Rider F – Phase II Energy Efficiency and Conservation Charge
Rider G - Smart Meter Technologies Charge
Rider J - Default Service Support Charge
Rider N - Solar Photovoltaic Requirements Charge
Rider P – Non-Utility Generation Charge

RATE SCHEDULES

Rate RS (continued)

DEFAULT SERVICE CHARGES:

For Customers receiving Default Service from the Company, Rider H – Price to Compare Default Service Rate Rider, Residential Customer Class rate applies.

MINIMUM CHARGE:

The monthly Minimum Charge shall be $13.29 plus distribution energy charges and any charges related to applicable riders.

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

EQUAL PAYMENT PLAN:

As per Rule 10b(4), Equal Payment Plan.

SPECIAL MONTHLY CHARGES

LOADS IN EXCESS OF 25 KILOWATTS: The Company shall install a suitable demand meter to determine the maximum 15-minute integrated demand when (i) a Customer's service requires the installation of an individual transformer, (ii) a Customer's total monthly consumption exceeds 10,000 kilowatt-hours for two (2) consecutive months, or (iii) when the Customer's service entrance requirements exceed 600 amperes.

If the demand so determined under this provision exceeds twenty-five (25) kilowatts, a monthly distribution demand charge of Two Dollars ($2.00) per kW for all kW shall apply to such excess as set forth in this Provision A, in addition to the General Monthly Charges. In no event shall the demand charge be based upon less than seventy-five percent (75%) of the highest excess demand during the preceding eleven (11) months.

RATE SCHEDULES

Rate RS (continued)

GENERAL PROVISIONS:

A. SERVICE TO EXISTING STRUCTURES CONVERTED FOR MULTIPLE OCCUPANCY: May be supplied through a single meter at the Company's option provided that the Company's prior consent has been obtained. This provision shall be limited to no more than eight (8) apartments or dwelling units continually served as such prior to September 18, 1978 and no more than two (2) apartments or dwelling units after September 18, 1978.

B. CUSTOMER ASSISTANCE PROGRAM: Customers who are enrolled in the Company's Customer Assistance Program may make payments to the Company in accordance with the Customer Assistance Program provided that electricity consumption limits and other requirements contained in the Customer Assistance Program are satisfied. Customer Assistance Program benefits shall be portable.

C. RESIDENTIAL FARM CUSTOMERS: Customers using the Company's service to a farm residence for residential purposes and, at the Customer's option, using such service for associated incidental "general farm uses" (including milk production) outside the dwelling unit shall be considered Residential Farm Customers. Where the Company has made a commitment to existing Customers prior to January 13, 1986, electric service through the farm residence meter may be used for "specialized farm operations" such as broiler raising, egg-laying houses, hatcheries, mushroom growing, greenhouses and similar specialized operations which produce items for sale, or produce items for others on a contract basis. Those Customers who choose an EGS and then return to the Company for their energy supply shall be billed under the appropriate General Service Rate. Electric service used in storing, processing, preparing or distributing products not raised on that farm shall not be considered as Residential Service and shall be separately metered and billed on the applicable Rate GS Rate Schedules.

Rules and Regulations:

The Company's Standard Rules and Regulations shall apply to the installation and use of electric service. Motors and equipment served under this rate schedule shall have electrical characteristics so as not to interfere with service supplied to other customers of the Company.

RATE SCHEDULES

RATE GS
VOLUNTEER FIRE COMPANY AND NON-PROFIT AMBULANCE SERVICE, RESCUE SQUAD AND SENIOR CENTER SERVICE RATE

AVAILABILITY:

This Rate Schedule is restricted to Volunteer Fire Companies, Non-Profit Ambulance Services, Non-Profit Rescue Squads and Non-Profit Senior Citizen Centers that sign a one (1) year contract.

All of the following general monthly charges are applicable to Delivery Service Customers:

GENERAL MONTHLY CHARGES:

Distribution Charge

$13.29 per month (Customer Charge), plus
4.103 cents per kWh for all kWh

RIDERS

Bills rendered under this schedule are subject to the following applicable Rider Charges:

Rider A – Tax Adjustment Surcharge
Rider B - Storm Damage Charge
Rider C – Universal Service Cost Charge
Rider F - Phase II Energy Efficiency and Conservation Charge
Rider G - Smart Meter Technologies Charge
Rider J - Default Service Support Charge
Rider N - Solar Photovoltaic Requirements Charge
Rider P – Non-Utility Generation Charge

RATE SCHEDULES

Rate GS (continued)

DEFAULT SERVICE CHARGES:

For Customers receiving Default Service from the Company, Rider H – Price to Compare Default Service Rate Rider, Residential Customer Class rate applies.

MINIMUM CHARGE:

The monthly Minimum Charge shall be $13.29 plus energy-related distribution charges and any applicable riders.

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

SPECIAL MONTHLY CHARGES

LOADS IN EXCESS OF 25 KILOWATTS: The Company shall install a suitable demand meter to determine the maximum 15-minute integrated demand when (i) a Customer's service requires the installation of an individual transformer, or (ii) a Customer's total monthly consumption exceeds 10,000 kilowatt-hours for two (2) consecutive months or (iii) when the Customer's service entrance requirements exceed 600 amperes. If the demand so determined under this provision exceeds twenty-five (25) kilowatts, a monthly distribution demand charge of Two Dollars ($2.00) per kW for all kW shall apply to such excess as set forth in this provision, in addition to the General Monthly Charges. In no event shall the demand charge be based upon less than seventy-five percent (75%) of the highest excess demand during the preceding eleven (11) months.

Rules and Regulations:

The Company's Standard Rules and Regulations shall apply to the installation and use of electric service. Motors and equipment served under this rate schedule shall have electrical characteristics so as not to interfere with service supplied to other customers of the Company.

RATE SCHEDULES

RATE GS-SMALL
GENERAL SERVICE SECONDARY RATE – NON DEMAND METERED

AVAILABILITY:

Available to non-Residential Customers without demand meters that use electric service through a single delivery location for lighting, heating and/or power service. Secondary voltage shall be supplied to Customers at a single transformer location when load does not require transformer capacity in excess of 2,500 KVA. Upon a Customer's request, the Company may, at its option, provide transformers having a capacity of greater than 2,500 KVA.

If an existing Customer's total consumption exceeds 1,500 KWH per month for two (2) consecutive months, the Customer shall no longer be eligible for service under this Rate Schedule GS-Small. Based upon the Company's then estimate of the Customer's new demand, the Customer shall be placed on Rate Schedule GS-Medium or such other Rate Schedule for which such Customer most qualifies.

All of the following general monthly charges are applicable to Delivery Service Customers:

GENERAL MONTHLY CHARGES:

Distribution Charge

$16.53 per month for single phase (Customer Charge), plus

3.082 cents per kWh for all billed kWh

RIDERS

Bills rendered under this schedule are subject to the following applicable Rider Charges:

Rider A – Tax Adjustment Surcharge
Rider B - Storm Damage Charge
Rider F - Phase II Energy Efficiency and Conservation Charge
Rider G - Smart Meter Technologies Charge
Rider J - Default Service Support Charge
Rider N - Solar Photovoltaic Requirements Charge
Rider P – Non-Utility Generation Charge

RATE SCHEDULES

Rate GS-Small (continued)

DEFAULT SERVICE CHARGES:

For Customers receiving Default Service from the Company, Rider H - Price to Compare Default Service Rate Rider, Commercial Customer Class rate applies unless the Customer elects to receive Default Service from the Company under Rider I – Hourly Pricing Default Service Rider.

MINIMUM CHARGE:

The monthly Minimum Charge shall be $16.53.

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

TERM OF CONTRACT

Each Customer shall be required to enter into a Delivery Service contract with the Company for a minimum one (1) year term. If the Delivery Service contract is terminated by the Customer prior to its expiration, the Minimum Charge provisions of this Rate Schedule shall apply. If the Customer's capacity or service requirements increase, the Company, in its sole and exclusive judgment, may at any time require the Customer to enter into a new Delivery Service contract.

RATE SCHEDULES

Rate GS-Small (continued)

SPECIAL PROVISION:

FIXED USAGE:

The Company may, in its sole and exclusive discretion, permit Customers to take service under this Special Provision. For Customers permitted by the Company to take service under this Special Provision, the Company may, in its sole and exclusive discretion, impute a level of energy and demand for that Customer based upon the Customer's projected load and hours of use for that load.

Rules and Regulations:

The Company's Standard Rules and Regulations shall apply to the installation and use of electric service. Motors and equipment served under this rate schedule shall have electrical characteristics so as not to interfere with service supplied to other customers of the Company.

RATE SCHEDULES

RATE GS-MEDIUM
GENERAL SERVICE SECONDARY RATE – DEMAND METERED

AVAILABILITY:

Available to non-Residential Customers that use electric service through a single delivery location for lighting, heating and/or power service up to 400 kW demand. Secondary voltage shall be supplied to Customers at a single transformer location when load does not require transformer capacity in excess of 2,500 KVA. Upon a Customer's request, the Company may, at its option, provide transformers having a capacity of greater than 2,500 KVA.

New Customers requiring transformer capacity in excess 2,500 KVA and existing Customers whose load increases such that a transformer change is required (over 2,500 KVA) shall be required to take untransformed service.

If an existing Customer's total consumption is less than 1,500 KWH per month for twelve (12) consecutive months, the Customer may no longer be eligible for service under this Rate Schedule GS-Medium. Based upon the Company's then estimate of the Customer's usage, the Customer shall be placed on Rate Schedule GS-Small or such other Rate Schedule for which such Customer most qualifies.

If an existing Customer's billing demand exceeds 400 kW for more than two (2) consecutive months in any 12-month period, then the Customer may no longer be eligible for service under this Rate Schedule GS-Medium, and shall be placed on Rate Schedule GS-Large or such other Rate Schedule for which such Customer most qualifies.

All of the following general monthly charges are applicable to Delivery Service Customers:

GENERAL MONTHLY CHARGES:

Distribution Charge

$19.01 per month for single phase (Customer Charge),
or
$34.39 per month for three phase (Customer Charge), plus

Demand

$5.22 per kW for all billing kW

$0.20 for each rkVA of Reactive Billing Demand

Energy

0.000 cents per kWh for all kWh

RATE SCHEDULES

Rate GS-Medium (continued)

RIDERS

Bills rendered under this schedule are subject to the following applicable Rider Charges:

Rider A – Tax Adjustment Surcharge
Rider B - Storm Damage Charge
Rider F - Phase II Energy Efficiency and Conservation Charge
Rider G - Smart Meter Technologies Charge
Rider J - Default Service Support Charge
Rider N - Solar Photovoltaic Requirements Charge
Rider P – Non-Utility Generation Charge

RATE SCHEDULES

Rate GS-Medium (continued)

DEFAULT SERVICE CHARGES:

For Customers receiving Default Service from the Company, Rider H – Price to Compare Default Service Rate Rider, Commercial Customer Class rate applies unless the Customer elects to receive Default Service from the Company under Rider I – Hourly Pricing Default Service Rider.

DETERMINATION OF BILLING DEMAND:

The Company shall install suitable demand meters to determine the maximum 15-minute integrated demand when (i) the connected load being served equals fifteen (15) kilowatts or more, or (ii) the Company estimates that a demand greater than five (5) kilowatts will be established. The Company may install a demand meter on new or upgraded electric services.

A determination of connected load or estimated demand may be made by the Company at any time and shall be made when the Customer's total consumption exceeds 1,500 KWH per month for two (2) consecutive months.

A Customer's demand shall be measured by indicating or recording instruments. Demands shall be integrated over 15-minute intervals. The billing demand in the current month shall be the greatest of: (i) the maximum measured demand established in the month during On-peak hours, as stated herein, (ii) forty percent (40%) of the maximum measured demand established in the month during Off-peak hours, or (iii) contract demand.

REACTIVE BILLING DEMAND:

For installations metered with reactive energy metering, the reactive billing demand in rkVA for the month shall be determined by multiplying the Billing Demand by the ratio of the measured lagging reactive kilovoltamperes hours to the measured kWh by the following formula: rkVA = Billing Demand X (measured lagging reactive kilovoltampere hours ÷ rate measured kWh). For all other installations, the Reactive Billing Demand shall be the integrated reactive demand occurring coincident with the Billing Demand.

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

TERM OF CONTRACT:

Each Customer shall be required to enter into a Delivery Service contract with the Company for a minimum one (1) year term. If the Delivery Service contract is terminated by the Customer prior to its expiration, the Minimum Charge provisions of this Rate Schedule shall apply. If the Customer's capacity or service requirements increase, the Company, in its sole and exclusive judgment, may at any time require the Customer to enter into a new Delivery Service contract.

RATE SCHEDULES

Rate GS-Medium (continued)

MINIMUM CHARGE:

No bill shall be rendered by the Company for less than,

$19.01 per month for single phase,
or
$34.39 per month for three phase, plus

The demand charges at current rate levels times the Billing Demand, plus any distribution energy charges, and any charges stated in or calculated by any applicable Rider.

COMBINED BILLING: THIS PROVISION HAS BEEN RESTRICTED TO PRESENT LOCATIONS SINCE SEPTEMBER 18, 1978. Only one standard single phase metered service and one standard three-phase metered service, each in excess of five (5) KW measured demand for each service, shall be supplied at one contract location, and when so supplied the energy and demand registrations of the separate meters shall be determined separately and may be added for billing purposes when the use of capacity on each service will remain in excess of five (5) KW for each month of the contract year.

Each separate and non-contiguous point of delivery or service installation shall be considered a contract location and shall be metered and billed under a separate service contract.

SERVICE AT PRIMARY VOLTAGE: Customers served at Primary Voltage shall have the option to be billed under this Rate GS-Medium for any of the following conditions:

1. A Customer with an estimated maximum demand of 1,000 KW or less, and requiring Primary Service at a voltage less than the nearest available Primary Voltage System.

2. Customer's maximum billing demand does not exceed 100 KW for more than two (2) consecutive months in any 12-month period and service is supplied through a Customer-owned transformer at the nearest available Primary Voltage System.

Rules and Regulations:

The Company's Standard Rules and Regulations shall apply to the installation and use of electric service. Motors and equipment served under this rate schedule shall have electrical characteristics so as not to interfere with service supplied to other customers of the Company.

RATE SCHEDULES

RATE GS-LARGE
GENERAL SERVICE SECONDARY - TIME-OF-DAY RATE

AVAILABILITY:

This Rate is available to non-Residential Customers using electric service through a single delivery location for lighting, heating and/or power service whose registered demand is equal to or greater than 400 KW in two (2) consecutive months. Secondary voltage shall be supplied to Customers at a single transformer location when load does not require transformer capacity in excess of 2,500 KVA. Upon a Customer's request, the Company may, at its option, provide transformers having a capacity of greater than 2,500 KVA.

New Customers requiring transformer capacity in excess 2,500 KVA and existing Customers whose load increases such that a transformer change is required (over 2,500 KVA) shall be required to take untransformed service.

All of the following general monthly charges are applicable to Delivery Service Customers:

GENERAL MONTHLY CHARGES:

Distribution Charge

$93.87 per month (Customer Charge), plus

$3.63 per kW for all billing kW

$0.20 for each rkVA of Reactive Billing Demand

RIDERS

Bills rendered under this schedule are subject to the following applicable Rider Charges:

Rider A – Tax Adjustment Surcharge
Rider B - Storm Damage Charge
Rider F - Phase II Energy Efficiency and Conservation Charge
Rider G - Smart Meter Technologies Charge
Rider J - Default Service Support Charge
Rider N - Solar Photovoltaic Requirements Charge
Rider P – Non-Utility Generation Charge

RATE SCHEDULES

Rate GS-Large (continued)

DEFAULT SERVICE CHARGES:

For Customers receiving Default Service from the Company, the Hourly Pricing Default Service Rider, Rider I, rates apply.

DETERMINATION OF BILLING DEMAND:

A Customer's demand shall be measured by indicating or recording instruments. Demands shall be integrated over 15-minute intervals. The billing demand in the current month shall be the greatest of: (i) the maximum measured demand established in the month during On-peak hours, as stated herein, (ii) forty percent (40%) of the maximum measured demand established in the month during Off-peak hours, (iii) contract demand or (iv) fifty percent (50%) of the highest billing demand established during the preceding eleven (11) months.

RATE SCHEDULES

Rate GS-Large (continued)

REACTIVE BILLING DEMAND:

For installations metered with reactive energy metering, the reactive billing demand in rkVA for the month shall be determined by multiplying the Billing Demand by the ratio of the measured lagging reactive kilovoltamperes hours to the measured kWh by the following formula: rkVA = Billing Demand X (measured lagging reactive kilovoltampere hours ÷ rate measured kWh). For all other installations, the Reactive Billing Demand shall be the integrated reactive demand occurring coincident with the Billing Demand.

MINIMUM CHARGE:

No bill shall be rendered by the Company for less than,

$93.87 per month plus,

The demand charges at current rate levels times the Billing Demand, plus distribution energy charges, and any charges stated in or calculated by any applicable Rider.

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

TERM OF CONTRACT:

Each Customer shall be required to enter into a Delivery Service contract with the Company for a minimum one (1) year term. If the Delivery Service contract is terminated by the Customer prior to its expiration, the Minimum Charge provisions of this Rate Schedule shall apply. If the Customer's capacity or service requirements increase, the Company, in its sole and exclusive judgment, may at any time require the Customer to enter into a new Delivery Service contract.

Rules and Regulations:

The Company's Standard Rules and Regulations shall apply to the installation and use of electric service. Motors and equipment served under this rate schedule shall have electrical characteristics so as not to interfere with service supplied to other customers of the Company.

RATE SCHEDULES

RATE GP
GENERAL SERVICE – PRIMARY RATE

AVAILABILITY/APPLICABILITY:

Available to non-Residential Customers using electric power and/or lighting service through a single delivery location at 2,400 volts or higher. Choice of voltage shall be at the option of the Company. All substation and transformer equipment required for utilization of the delivery voltage shall be owned and maintained by the Customer. As described more fully in the next paragraph, this Rate Schedule shall be applicable to the owner of any Generating Facility whose Generating Facility is interconnected to the Company's electric system, if the Company believes, in its sole and exclusive discretion, that the provisions of this Rate Schedule are otherwise available to the Generating Facility.

The Company shall determine the applicability of this Rate Schedule to Generating Facility owners in its sole and exclusive discretion. If and when the Company determines that the owner of a Generating Facility interconnected to the Company's system has not previously entered into Tariff or other arrangements satisfactory to the Company allowing it to charge and receive payment of Delivery Service Charges, Default Service Charges and/or Net Station Power, as applicable, the Company will assign the Generating Facility to this Rate Schedule if the Company believes, the provisions of this Rate Schedule are otherwise available to the Generating Facility. For any hour in which the Company has determined the Generating Facility receives energy or capacity, as metered at or near such facility, the Generating Facility owner shall be responsible for paying to the Company all Delivery Service charges and/or Default Service Charges, applicable, based upon the metered energy and demand. In addition, the Generating Facility owner shall be responsible for paying to the Company all charges associated with Net Station Power for each applicable billing period based upon the Default Service rates specified in this Rate Schedule.

Minimum billing demand shall not be less than twenty-five (25) KW

All of the following general monthly charges are applicable to Delivery Service Customers:

RATE SCHEDULES

Rate GP (continued)

GENERAL MONTHLY CHARGES:

Distribution Charge

$308.19 per month, plus

Demand
$3.35 per kW for all billed kW

$0.20 for each rkVA of Reactive Billing Demand

Energy
0.000 cents per kWh for all kWh

RIDERS

Bills rendered under this schedule are subject to the following applicable Rider Charges:

Rider A – Tax Adjustment Surcharge
Rider B - Storm Damage Charge
Rider F - Phase II Energy Efficiency and Conservation Charge
Rider G - Smart Meter Technologies Charge
Rider J - Default Service Support Charge
Rider N - Solar Photovoltaic Requirements Charge
Rider P – Non-Utility Generation Charge

DEFAULT SERVICE CHARGES:

For Customers receiving Default Service from the Company, the Hourly Pricing Default Service Rider, Rider I, rates apply.

RATE SCHEDULES

Rate GP (continued)

DETERMINATION OF BILLING DEMAND:

The Customer's demand shall be measured by indicating or recording instruments. Demand shall be integrated over 15-minute intervals or as otherwise determined by the Company. The billing demand in the current month shall be the greatest of: (i) twenty-five (25) KW, (ii) the maximum measured demand established in the month during On-peak hours, as stated herein, (iii) forty percent (40%) of the maximum measured demand established in the month during Off-peak hours, (iv) contract demand or (v) fifty percent (50%) of the highest billing demand established during the preceding eleven (11) months.

REACTIVE BILLING DEMAND:

For installations metered with reactive energy metering, the reactive billing demand in rkVA for the month shall be determined by multiplying the Billing Demand by the ratio of the measured lagging reactive kilovoltamperes hours to the measured kWh by the following formula: rkVA = Billing Demand X (measured lagging reactive kilovoltampere hours ÷ rate measured kWh). For all other installations, the Reactive Billing Demand shall be the integrated reactive demand occurring coincident with the Billing Demand.

For the purposes of determining the demand for Net Station Power of a Generating Facility under this Rate Schedule, registered demand during any hour cannot be netted, offset or credited against capacity from that Generating Facility in any other hour or from registered capacity from any other Generating Facility in any other hour.

RATE SCHEDULES

Rate GP (continued)

STATION POWER ENERGY NETTING:

If applicable PJM rules and procedures for determining Net Station Power are in effect, all Net Station Power shall be determined solely by PJM and provided to the Company for billing purposes under this Rate Schedule. If the Applicant self-supplies Net Station Power, the Applicant shall be responsible for obtaining all related transmission service. If no such applicable PJM rules and procedures for determining Net Station Power are in effect or PJM is unable for any reason to determine Net Station Power, the Company shall determine Net Station Power for any relevant period in its sole discretion.

MINIMUM CHARGE:

No bill shall be rendered by the Company for less than,

$308.19 per month, plus

the higher of (i) the demand charges at current rate levels times the Billing Demand, plus any distribution energy charges, and any charges stated in or calculated by any applicable Rider.

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

TERM OF CONTRACT:

Each Customer shall be required to enter into a Delivery Service contract with the Company for a minimum one (1) year term. If the Delivery Service contract is terminated by the Customer prior to its expiration, the Minimum Charge provisions of this Rate Schedule shall apply. If the Customer's capacity or service requirements increase, the Company, in its sole and exclusive judgment, may at any time require the Customer to enter into a new Delivery Service contract.

Rules and Regulations:

The Company's Standard Rules and Regulations shall apply to the installation and use of electric service. Motors and equipment served under this rate schedule shall have electrical characteristics so as not to interfere with service supplied to other customers of the Company.

RATE SCHEDULES

RATE TP
TRANSMISSION POWER RATE

AVAILABILITY/APPLICABILITY:

This Rate Schedule is available to non-Residential Customers using electric power and/or lighting service through a single delivery location and at a single delivery voltage at available nominal transmission voltages whose registered demand is equal to or greater than 5,000 KW in two (2) consecutive months. Choice of voltage shall be at the option of the Company. All substation, transformer, voltage regulating, and other equipment required for utilization of the delivery voltage shall be owned and maintained by the Customer. Existing Rate TP Customers at existing locations, irrespective of their current service voltage or substation ownership, may remain on Rate TP unless their load level does not meet the requirements of Rate TP. However, if the Customer's load level increases and requires the Company's substation or voltage level to change, the Company may require the Customer to provide their own substation and take service at a voltage level under which the Customer qualifies for service under this Rate Schedule. As described more fully in the next paragraph, this Rate Schedule shall be applicable to the owner of any Generating Facility whose Generating Facility is interconnected to the Company's electric system, if the Company believes, in its sole and exclusive discretion, that the provisions of this Rate Schedule are otherwise available to the Generating Facility.

The Company shall determine the applicability of this Rate Schedule to Generating Facility owners in its sole and exclusive discretion. If and when the Company determines that the owner of a Generating Facility interconnected to the Company's system has not previously entered into Tariff or other arrangements satisfactory to the Company allowing it to charge and receive payment of Delivery Service Charges, Default Service Charges and/or Net Station Power, as applicable, the Company will assign the Generating Facility to this Rate Schedule if the Company believes the provisions of this Rate Schedule are otherwise available to the Generating Facility. For any hour in which the Company has determined the Generating Rate Facility receives energy or capacity, as metered at or near such facility, the Generating Facility owner shall be responsible for paying to the Company all Delivery Service Charges and/or Default Service Charges, as applicable, based upon the metered energy and demand. In addition, the Generating Facility owner shall be responsible for paying to the Company all charges associated with Net Station Power for each applicable billing period based upon the Default Service rates specified in this Rate Schedule.

Minimum billing demand shall not be less than 5,000 KW.

All of the following general monthly charges are applicable to Delivery Service Customers:

RATE SCHEDULES

Rate TP (continued)

GENERAL MONTHLY CHARGES:

Distribution Charge

$1,149.15 per month (Customer Charge), plus

$1.03 per kW for all billed kW

RIDERS

Bills rendered under this schedule are subject to the following applicable Rider Charges:

Rider A – Tax Adjustment Surcharge
Rider B - Storm Damage Charge
Rider F - Phase II Energy Efficiency and Conservation Charge
Rider G - Smart Meter Technologies Charge
Rider J - Default Service Support Charge
Rider N - Solar Photovoltaic Requirements Charge
Rider P – Non-Utility Generation Charge

RATE SCHEDULES

Rate TP (continued)

DEFAULT SERVICE CHARGES:

For Customers receiving Default Service from the Company, the Hourly Pricing Default Service Rider, Rider I, rates apply.

DETERMINATION OF BILLING DEMAND:

The Customer's demand shall be measured by indicating or recording instruments. Demand shall be integrated over 15-minute intervals or as otherwise determined by the Company. The billing demand in the current month shall be the greater of: (i) 5,000 KW, (ii) the maximum measured demand established in the month during On-peak hours, adjusted for Power Factor as stated herein, (iii) forty percent (40%) of the maximum measured demand established in the month during Off-peak hours, (iv) contract demand (v) fifty percent (50%) of the highest billing demand established during the preceding eleven (11) months.

For purposes of determining the demand for Net Station Power of a Generating Facility under this Rate Schedule, registered demand during any hour cannot be netted, offset or credited against capacity from that Generating Facility in any other hour or from registered capacity from any other Generating Facility in any other hour.

STATION POWER ENERGY NETTING:

If applicable PJM rules and procedures for determining Net Station Power are in effect, all Net Station Power shall be determined solely by PJM and provided to the Company for billing purposes under this Rate Schedule. If the Applicant self-supplies Net Station Power, the Applicant shall be responsible for obtaining all related transmission service. If no such applicable PJM rules and procedures for determining Net Station Power are in effect or PJM is unable for any reason to determine Net Station Power, the Company shall determine Net Station Power for any relevant period in its sole discretion.

RATE SCHEDULES

Rate TP (continued)

MINIMUM CHARGE:

No bill shall be rendered by the Company for less than,

$1,149.15 per month, plus

the demand charges at current rate levels times the Billing Demand, plus any distribution energy charges, and any charges stated in or calculated by any applicable Riders.

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

TERM OF CONTRACT:

Each Customer shall be required to enter into a Delivery Service contract with the Company for a minimum one (1) year term. If the Delivery Service contract is terminated by the Customer prior to its expiration, the Minimum Charge provisions of this Rate Schedule shall apply. If the Customer's capacity or service requirements increase, the Company, in its sole and exclusive judgment, may at any time require the Customer to enter into a new Delivery Service contract.

RATE SCHEDULES

Rate TP (continued)

GENERAL PROVISIONS:

A. VOLTAGE DISCOUNT - 115 KV OR GREATER:

If the Company, in its sole discretion, elects to serve a Customer at 115 KV or greater, the demand charge shall be decreased as set forth below:

Credit for:	Demand Dollars/KW
Distribution	$0.31

Rules and Regulations:

The Company's Standard Rules and Regulations shall apply to the installation and use of electric service. Motors and equipment served under this rate schedule shall have electrical characteristics so as not to interfere with service supplied to other customers of the Company.

RATE SCHEDULES

RATE MS
MUNICIPAL SERVICE RATE

AVAILABILITY (RESTRICTED):

THE AVAILABILITY OF THIS RATE SCHEDULE TO CUSTOMERS HAS BEEN RESTRICTED SINCE OCTOBER 19, 1983.

Municipal lighting, and/or power and/or heating service used by counties, cities, boroughs, townships and public school districts for public purposes only and not applicable to service where counties, cities, boroughs, townships or public school districts are compensated in any form (other than admissions collected by such bodies) for the use of any of the facilities for which service is supplied.

Secondary Voltage: Secondary voltage will be supplied by the Company to Customers at a single transformer location when load does not require transformer capacity in excess of 2,500 KVA.

Primary Voltage: New Customers requiring transformer capacity in excess of 2,500 KVA and existing Customers whose load increases such that a transformer change is required (over 2,500 KVA) shall be required to take untransformed service.

All of the following general monthly charges are applicable to Delivery Service Customers:

GENERAL MONTHLY CHARGES:

Distribution Charge

$34.34 per month (Customer Charge), plus
4.448 cents per kWh for all kWh

RIDERS

Bills rendered under this schedule are subject to the following applicable Rider Charges:

Rider A – Tax Adjustment Surcharge
Rider B - Storm Damage Charge
Rider F - Phase II Energy Efficiency and Conservation Charge
Rider G - Smart Meter Technologies Charge
Rider J - Default Service Support Charge
Rider N - Solar Photovoltaic Requirements Charge
Rider P – Non-Utility Generation Charge

RATE SCHEDULES

Rate MS (continued)

DEFAULT SERVICES CHARGES:

For Customers receiving Default Service from the Company, Rider H – Price to Compare Default Service Rate Rider, Commercial Customer Class rate applies.

MINIMUM CHARGE:

The monthly Minimum Charge shall be $34.34 plus all distribution energy charges and any charges stated in or calculated by any applicable Riders.

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

TERM OF CONTRACT:

Each Customer shall be required to enter into a Delivery Service contract with the Company for a minimum one (1) year term. If the Delivery Service contract is terminated by the Customer prior to its expiration, the Minimum Charge provisions of this Rate Schedule shall apply. If the Customer's capacity or service requirements increase, the Company, in its sole and exclusive judgment, may at any time require the Customer to enter into a new Delivery Service contract.

Rules and Regulations:

The Company's Standard Rules and Regulations shall apply to the installation and use of electric service. Motors and equipment served under this rate schedule shall have electrical characteristics so as not to interfere with service supplied to other customers of the Company.

SERVICES

BORDERLINE SERVICE

AVAILABILITY:

Borderline Service is available to public utility companies for resale in adjacent service territory to the Company under reciprocal agreements between the Company and other public utility companies, subject to the following conditions:

A. A request shall be made in writing for each point of supply where service is desired.

B. Borderline service may be supplied in the Company's sole and exclusive discretion when it has available adequate capacity to serve the requested location(s).

C. When such service is supplied, energy shall be supplied at sixty (60) cycle alternating current, at such potential and of such phase as may be mutually agreed upon.

All of the following general monthly charges are applicable to Delivery Service Customers.

GENERAL MONTHLY CHARGES:

Distribution Charge

2.251 cents per kWh for all kWh

RIDERS

Bills rendered under this schedule are subject to the following applicable Rider Charges:

Rider A – Tax Adjustment Surcharge
Rider B - Storm Damage Charge
Rider J - Default Service Support Charge
Rider N - Solar Photovoltaic Requirements Charge
Rider P – Non-Utility Generation Charge

SERVICES

Borderline Service (continued)

DEFAULT SERVICE CHARGES:

For Customers receiving Default Service from the Company, Rider H – Price to Compare Default Service Rate Rider, Commercial Customer Class rate applies.

INVESTMENT CHARGE:

One percent (1%) on the Company's investment in facilities necessary to deliver and meter the service.

The energy may be metered at the point of supply or at the nearest suitable point, or the energy may be estimated from the sum of the meter readings of purchaser's customers, plus an agreed upon correction to cover transformation and the line losses from the point of supply.

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

TERM OF CONTRACT:

A contract shall be written for a period of not less than five (5) years.

Rules and Regulations:

The Company's Standard Rules and Regulations shall apply to the installation and use of electric service. Motors and equipment served under this rate schedule shall have electrical characteristics so as not to interfere with service supplied to other customers of the Company.

SERVICES

STREET LIGHTING SERVICE

AVAILABILITY:

This Service is applicable to overhead or underground street lighting service to municipal, local, state and federal governmental bodies, community associations and to public authorities for lighting of streets, highways, parks and similar places for the safety and convenience of the public. This Service supersedes Rate SV, Rate MH, Rate MV-1, Rate MV-2, Rate SL and Rate OSL, excepting Rate OSL, Provision A - Post Top Series Incandescent Street Lighting.

TYPE OF SERVICE:

The Company will provide unmetered energy, at the rate herein provided, when the Customer furnishes, installs, owns and maintains (including lamp and photocell) the entire lighting system consisting of, but not limited to, lamps, luminaries, controls, brackets, ballasts, conductors, and poles. Lighting units will operate from dusk to dawn, which is approximately 4,200 hours per year. The Company will supply electricity at mutually agreed upon delivery points for the operation of the lights. The Company may, at any time, inspect and/or test the Customer's equipment to verify or measure actual load. This service is limited to installations of contiguous Metal Halide street lighting units located in an area previously approved by the Company or limited to Sodium Vapor, Mercury Vapor or Incandescent street light units also served under General Provision A or General Provision D of this Service.

GENERAL MONTHLY CHARGES:

Demand and Energy Charges for common lamp sizes:

Charges Per Month Per Light:

Sodium Vapor:

Nominal Watts	Monthly kWh	Distribution	Monthly Minimum Charge
70	32	0.00	6.26
100	46	0.00	6.13
150	66	0.00	6.04
200	75	0.00	5.67
250	98	0.00	6.43
400	156	0.00	6.29
800	312	0.00	6.04

SERVICES

Street Lighting Service (continued)

Mercury Vapor:

Nominal Watts	Monthly kWh	Distribution	Monthly Minimum Charge
100	42	0.00	6.34
175	74	0.00	6.14
250	107	0.00	5.86
400	174	0.00	5.25
1000	420	0.00	4.02

Incandescent:

Nominal Watts	Monthly kWh	Distribution	Monthly Minimum Charge
105	44	0.00	6.24
205	86	0.00	5.93
327	137	0.00	5.15
860	361	0.00	4.15

Metal Halide:

Nominal Watts	Monthly kWh	Distribution	Monthly Minimum Charge
175	70	0.00	6.35
250	98	0.00	6.35
400	156	0.00	6.22

Overhead Alternative Technology Lighting:

Distribution	Monthly Minimum Charge
0.00	6.13

SERVICES

Street Lighting Service (continued)

RIDERS

Bills rendered under this schedule are subject to the following applicable Rider Charges:

Rider A – Tax Adjustment Surcharge
Rider B - Storm Damage Charge
Rider F - Phase II Energy Efficiency and Conservation Charge
Rider G - Smart Meter Technologies Charge
Rider J - Default Service Support Charge
Rider N - Solar Photovoltaic Requirements Charge
Rider P – Non-Utility Generation Charge

SERVICES

Street Lighting Service (continued)

DEFAULT SERVICE CHARGES:

The Price to Compare Default Service Charge shall be determined using the applicable Monthly kWh usage, from the preceding chart, multiplied by the Price to Compare Default Service Rate Rider, Rider H, Commercial Customer Class rate.

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

TERM OF CONTRACT:

Provision of this Service requires a contract with the Company. The initial term of contract shall be not less than ten (10) years, subject to renewal for successive one (1) year terms, unless other terms shall be provided in the contract. When replacement with different type luminaire is requested by the Customer of an existing luminaire during the initial ten (10) year term of contract, the Customer shall pay the cost of removal in addition to the depreciable life of the fixture for the remainder of the contract term (to be determined by the Company). Under Provision B, the term of contract may be less than ten (10) years, but not less than one (1) year.

GENERAL PROVISIONS:

A. COMPANY OPERATION AND MAINTENANCE OF CONVENTIONAL LUMINAIRE: The Company will operate and maintain conventional (non-ornamental) Sodium Vapor, Mercury Vapor and Incandescent lighting units consisting of lamps, luminaries, controls, brackets and ballasts approved by the Company. These units will be installed on wood poles at mounting heights not to exceed forty-five (45) feet and in a manner acceptable to the Company. The Company will operate and maintain and replace the photocell controls and lamps as necessary to the extent hereinafter expressly provided at the following monthly rates and charges:

SERVICES

Street Lighting Service (continued)

	Charge Per Month Per Light
1. Sodium Vapor Lamps	$2.21
2. Mercury Vapor Lamps	$0.91
3. Incandescent Lamps	$2.48

Where, at the Company's option and upon Customer request, the Company has converted existing Mercury Vapor and Incandescent lights to High Pressure Sodium Vapor lights or has installed on existing poles a Company-owned standard Sodium Vapor luminaire, the Company will operate and maintain said luminaire at the rates and charges listed under Street Lighting Service this, General Provision A, provided the Customer has made a contribution, to be calculated annually.

B. COMPANY OWNERSHIP OF CONVENTIONAL LUMINAIRE FACILITIES: The Company will furnish and install and own its standard Sodium Vapor, Mercury Vapor and Incandescent conventional (non-ornamental) street lighting units consisting of lamps, luminaries, controls, brackets and ballasts, mounted on the Company's wood poles and utilizing the Company's overhead distribution system. For each light, the Company will furnish without added charge up to 300 feet of overhead line on existing suitable poles. At its option, the Company may install additional wood poles, provided that a street lighting unit is then installed on each dedicated pole.

The type of lighting units and fixtures currently being furnished by the Company at the time service is contracted for under this Service will be installed at the rates herein provided.

1. Charges Per Month Per Light:	$2.12
2. Charges Per Month Per Dedicated Pole:	$8.83

Street Lighting Service (continued)

INCANDESCENT LIGHTS SERVED UNDER THIS PROVISION ARE RESTRICTED TO PRESENT CUSTOMERS AND NO ADDITIONAL LIGHTS WILL BE INSTALLED, RELOCATED OR INCREASED IN SIZE HEREUNDER (FORMERLY RESTRICTED ON STREET LIGHTING SERVICE AS OF OCTOBER 22, 1968).

C. UNDERGROUND FEED TO STREET LIGHTS: This provision is for the installation of new facilities at new locations or the conversion of facilities at existing locations. Where the Company furnishes an underground electrical source, there shall be billed charges in addition to the other charges specified in this Service per light as follows:

Demand and Energy Charges for common lamp sizes:

Sodium Vapor:

Nominal Watts	Monthly kWh	Distribution	Monthly Minimum Charge
70	32	0.08	0.12
100	46	0.12	0.12
150	66	0.17	0.12
250	98	0.29	0.12
400	156	0.47	0.12
800	312	0.93	0.12

Mercury Vapor:

Nominal Watts	Monthly kWh	Distribution	Monthly Minimum Charge
100	42	0.12	0.12
175	74	0.21	0.12
250	107	0.29	0.12
400	174	0.47	0.12
700	294	0.81	0.12
800	348	0.93	0.12
1000	420	1.21	0.12

SERVICES

Street Lighting Service (continued)

Incandescent:

Nominal Watts	Monthly kWh	Distribution	Monthly Minimum Charge
105	44	0.13	0.12
205	86	0.24	0.12
327	137	0.38	0.12
448	188	0.52	0.12
690	290	0.80	0.12
860	361	1.00	0.12
1720	722	2.00	0.12

Metal Halide:

Nominal Watts	Monthly kWh	Distribution	Monthly Minimum Charge
175	70	0.21	0.12
250	98	0.29	0.12
400	156	0.47	0.12

Underground Alternative Technology Lighting:

*Distribution	Monthly Minimum Charge
0.218	0.12

*cents per kWh

The Company will provide and charge for NUG Charges to Customers taking Delivery Service in accordance with the provisions of Rider P – NUG Rider, which charge shall apply to all kWh billed under this Rate Schedule.

SERVICES

Street Lighting Service (continued)

DEFAULT SERVICE CHARGES:

The Price to Compare Default Service Charge shall be determined using the applicable Monthly kWh usage, from the preceding chart, multiplied by the Price to Compare Default Service Rate Rider, Rider H, Commercial Customer Class rate.

INCANDESCENT LIGHTS SERVED UNDER THIS PROVISION ARE RESTRICTED TO EXISTING CUSTOMERS AND NO ADDITIONAL LIGHTS WILL BE INSTALLED HEREUNDER OR RELOCATED OR INCREASED IN SIZE (FORMERLY RESTRICTED ON ORNAMENTAL STREET LIGHTING SERVICE AS OF OCTOBER 19, 1983).

The cost of trenching and backfilling, including breaking and replacement of concrete and other surfacing, and the provision and installation of duct or conduit (concrete encased where specified by the Company), where duct or conduit is required by the Company, shall be borne by the Customer. The cost of foundations required for support of standards shall be borne by the Customer, except that the Company will supply foundation bolts and conduit required for the installation in foundations. The Customer shall make such installations or contract with the Company or with others to do so, all to be in compliance with the Company's specifications. All installations made by (or for) the Customer shall be maintained by the Customer, except as next stated herein.

Upon mutual agreement with the Company, the Customer may transfer to the Company the ownership of such installations (except where an integral part of the Customer's property), and in the event of such transfer of ownership, the Company will thereafter maintain such equipment, and there shall be no change in the charges stated in the Rate Per Month of this Street Lighting Service, General Provisions D., E. and F.

D. COMPANY OPERATION & MAINTENANCE OF ORNAMENTAL LUMINARIES: The Company will operate and maintain ornamental Sodium Vapor, Mercury Vapor and Incandescent lighting units consisting of lamps, luminaire controls, brackets and ballasts approved by the Company and served from the Company's distribution system.

SERVICES

Street Lighting Service (continued)

These units will be installed on ornamental standards and in a manner acceptable to the Company. The Company will operate and maintain and replace the photocell controls and lamps as necessary to the extent hereinafter expressly provided at the following rates and charges:

	Charge Per Month Per Light
1. Sodium Vapor Lamps	$2.64
2. Mercury Vapor Lamps	$1.49
3. Incandescent Lamps	$2.60

Where, at the Company's option and upon Customer request, the Company has converted existing Mercury Vapor and Incandescent lights to High Pressure Sodium Vapor lights or has installed on a Company-owned standard a Company-owned standard Sodium Vapor luminaire, the Company will operate and maintain said luminaire at the rates and charges listed under Street Lighting Service, General Provision D., provided the Customer has made a contribution, to be calculated annually.

E. COMPANY OWNERSHIP OF ORNAMENTAL LUMINAIRE: Where at the approval of the Company, the Customer owns, installs and maintains the cable and ducts (or conduit) and the standards and foundation therefore and the Company owns, installs, and maintains its standard Sodium Vapor, Mercury Vapor or Incandescent Ornamental street light units consisting of only the lamp, ballast, control, luminaire (and its interior wiring), the Luminaire Charge per month for ornamental lights, not to exceed thirty-five (35) foot mounting height, will be as follows:

Luminaire Charge: $5.02 Per Light Per Month

F. COMPANY OWNERSHIP OF ORNAMENTAL STANDARDS: Where, at the Company's option and upon Customer request, the Company has installed on a Company-owned standard a Company-owned and Company-approved standard Sodium Vapor, Mercury Vapor or Incandescent ornamental luminaire, the Company will own, operate, and maintain said standard at the following rate:

$9.47 Standard Charge Per Month

Where, at the Company's option and upon Customer request, the Company has converted existing Mercury Vapor and Incandescent lights to High Pressure Sodium Vapor lights or has installed on a Company-owned standard a Company-owned standard Sodium Vapor luminaire, the Company will operate and maintain said luminaire at the following rates and charges provided the Customer has made a contribution, to be calculated annually.

$3.20 Standard Charge Per Month

SERVICES

Street Lighting Service (continued)

G. ALTERNATIVE TECHNOLOGY LIGHTING: The Alternative Technology Lighting charges shall apply to lighting facilities owned and maintained by the Customer which utilize Induction, Solid State, or Plasma Lighting technologies, or such additional alternative technology as may be specified by the Company. The Alternative Technology Lighting must be certified by an Edison Testing Laboratories "ETL" (or equivalent) to verify the actual consumption of the fixture. In addition and in order to certify the safe operation, the fixture must be Underwriters Laboratories "UL" (or equivalent) listed. Provisions A, B, D, E, and F shall not apply in the case of service provided under this General Provision G.

For purposes of the Provision G, the following definitions shall apply:

Induction Lighting – Discharge lamps, where mercury or other atoms are energized to elevate their energy level, then discharge a photon as they fall back to their normal state.

Solid State Lighting – Technology using semi-conducting materials to convert electricity into light. Solid State Lighting is an umbrella term encompassing both light-emitting diodes (LEDs) and organic light-emitting diodes (OLEDs).

Plasma Lighting – Plasma lamps are a family of light sources that generate light by exciting a plasma inside a closed transparent burner or bulb using a radio frequency (RF) power. Typically, such lamps use a noble gas or a mixture of these gases and additional materials such as metal halides, sodium, mercury, or sulfur. A waveguide is used to constrain and focus the electrical field into the plasma. In operation the gas is ionized and free electrons, accelerated by the electrical field collide with gas and metal atoms. Some electrons circling around the gas and metal atoms are excited by these collisions, bringing them to a higher energy state. When the electron falls back to its original state, it emits a photon, resulting in visible light or ultraviolet radiation depending on the fill materials.

Alternative Technology Lighting shall be applied to each kilowatt-hour delivered during a billing month to all Customers served under this specific provision, determined to the nearest one-hundredth of a cent per kilo-watt hour. In addition, the wattage of the Alternative Technology Lighting shall be rounded to the nearest 25 Watt. The Alternative Technology Lighting wattage will then be converted into kWh in accordance with the formula set forth below:

SERVICES

Street Lighting Service (continued)

$$kWh = \frac{(System\ Watt \times 350)}{1{,}000}$$

Where:

System Watt = Total Watts used (drawn) by the entire luminaire fixture.

RIDERS:

Bills rendered by the Company under this Service shall be subject to the charges stated in any applicable Rider. Rates identified in this Service include all charges developed and calculated in accordance with all applicable Riders in this Tariff, except for Rider A – Tax Adjustment Surcharge.

SERVICES

ORNAMENTAL STREET LIGHTING SERVICE

AVAILABILITY (RESTRICTED):

AVAILABLE ONLY AS A FULL SERVICE OPTION.

THIS SERVICE IS RESTRICTED TO EXISTING CUSTOMERS AND NO ADDITIONAL LIGHTS WILL BE INSTALLED HEREUNDER, OR INCREASED IN SIZE, EFFECTIVE OCTOBER 19, 1983. ANY CUSTOMER PRESENTLY SERVED UNDER THIS ORNAMENTAL STREET LIGHTING SERVICE AND ELECTS TO TERMINATE THIS SERVICE, SHALL NOT BE PERMITTED TO RETURN AS A ORNAMENTAL STREET LIGHTING SERVICE CUSTOMER.

Available for ornamental street lighting service and street lighting service for underpasses and bridges. Applicable only to municipal or other governmental bodies. Incandescent street lights may be relocated provided Customer pays Company the cost of such relocation, except that such lights will be installed only in areas already lighted predominantly by incandescent lights.

TYPE OF SERVICE:

The following conditions are applicable to all lights served and to all equipment supplied under this Service:

1. Lamps will be lighted from dusk to dawn, which is approximately 4,200 hours per year.

2. The lumen rating, where stated, is the manufacturers' stated nominal rating of lamps.

RIDERS

Bills rendered under this schedule are subject to the following applicable Rider Charges:

Rider A – Tax Adjustment Surcharge
Rider B - Storm Damage Charge
Rider F - Phase II Energy Efficiency and Conservation Charge
Rider G - Smart Meter Technologies Charge
Rider J - Default Service Support Charge
Rider N - Solar Photovoltaic Requirements Charge
Rider P – Non-Utility Generation Charge

SERVICES

Ornamental Street Lighting Service (continued)

DEFAULT SERVICE CHARGES:

The Price to Compare Default Service Charge shall be determined using the applicable Monthly kWh usage, from the preceding chart, multiplied by the Price to Compare Default Service Rate Rider, Rider H, Commercial Customer Class rate.

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

TERM OF CONTRACT:

Service supplied under this classification shall be for a period of not less than one (1) year.

SERVICES

Ornamental Street Lighting Service (continued)

GENERAL PROVISION:

POST TOP SERIES INCANDESCENT STREET LIGHTING (RESTRICTED): Where the Customer elects to take street lighting service from series incandescent street lighting facilities and the Company furnishes and maintains the entire street lighting systems, the monthly charge shall be as specified below:

Nominal Initial Rate Lamp Lumens:	2,500	6,000
Lamp Charge Per Month	$43.96	$34.68

SERVICES

LED STREET LIGHTING SERVICE

AVAILABILITY:

This Service is applicable to Company owned overhead or underground Light Emitting Diode (LED) street lighting service to municipal, local, state and federal governmental bodies, community associations and to public authorities for lighting of streets, highways, parks and similar places for the safety and convenience of the public.

A minimum installation of 12 LED lights per customer per individual order is required.

GENERAL MONTHLY CHARGES:

Demand and Energy Charges for common lamp sizes:

Charges Per Month Per Light:

Cobra Head

Nominal Watts	Monthly kWh	Distribution
50	18	$6.87
90	32	$8.61
130	46	$9.15
260	91	$14.14

Colonial

Nominal Watts	Monthly kWh	Distribution
50	18	$10.96
90	32	$12.05

Acorn

Nominal Watts	Monthly kWh	Distribution
50	18	$18.19
90	32	$19.22

SERVICES

LED Street Lighting Service (continued)

RIDERS

Bills rendered under this schedule are subject to the following applicable Rider Charges:

Rider A – Tax Adjustment Surcharge
Rider B - Storm Damage Charge
Rider F - Phase II Energy Efficiency and Conservation Charge
Rider G - Smart Meter Technologies Charge
Rider J - Default Service Support Charge
Rider N - Solar Photovoltaic Requirements Charge
Rider P – Non-Utility Generation Charge

DEFAULT SERVICE CHARGES:

The Price to Compare Default Service Charge shall be determined using the applicable Monthly kWh usage, from the preceding chart, multiplied by the Price to Compare Default Service Rate Rider, Rider H, Commercial Customer Class rate.

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

TERM OF CONTRACT:

Provision of this Service requires a contract with the Company. The initial term of contract shall be not less than ten (10) years, subject to renewal for successive one (1) year terms, unless other terms shall be provided in the contract. When replacement of existing lighting is requested by the Customer of an existing luminaire during the initial ten (10) year term, the Customer shall pay the cost of removal in addition to the depreciable life of the fixture for the remainder of the term (to be determined by the Company).

GENERAL PROVISIONS:

A. The Company shall furnish, install, and maintain at the above rates all necessary street lighting facilities consisting of but not limited to lamps, luminaries, brackets, and other supporting materials.

B. The Company will install lighting fixtures on an approved existing pole. All additional and new lighting equipment, consisting of but not limited to poles, brackets, wiring, transformation, etc., not provided for herein, installed by the Company at the request of the customer, shall be the property of the Company and be paid for by the customer prior to the customer taking service.

SERVICES

LED Street Lighting Service (continued)

C. Costs associated with activities related to the replacement, relocation, alteration, repair, or removal of existing street lighting equipment are not included as part of normal maintenance and will be the responsibility of the customer. Examples of such activities include, but are not limited to, the replacement of an existing fixture, removal or relocation of a lamp, luminaire, bracket, and/or pole, or installation of a luminaire shield.

D. All lamps shall be unmetered and will operate from dusk to dawn each and every night, or for approximately 4,200 hours per year.

E. If a Customer requests an underground system, it will be installed where service is supplied from an existing underground distribution system. Additional cost shall be borne by the Customer.

F. All service and necessary maintenance will be performed only during regular working hours of the Company. If service and necessary maintenance cannot be performed during regular working hours of the Company, for reasons beyond the Company's control, the incremental costs of performing such work shall be borne by the customer.

SERVICES

OUTDOOR AREA LIGHTING SERVICE

AVAILABILITY:

Available for lighting of outdoor areas and roadways from dusk to dawn, served from Company's existing overhead wood pole distribution system where 120-volt service is available and where the Company's sole determination that street lighting service is not appropriate. INSTALLATION OF MERCURY VAPOR LIGHTS UNDER THIS SERVICE IS RESTRICTED TO EXISTING LIGHTS AT PRESENT LOCATIONS AS OF OCTOBER 19, 1983.

THIS SERVICE SHALL BE FURTHER RESTRICTED TO EXISTING CUSTOMERS AT EXISTING LOCATIONS AS OF AUGUST 1, 2012.

RATE PER MONTH:

Watt	Monthly kWh	Distribution
175-Watt mercury vapor lamp	70	6.26
Sodium Vapor		
100-Watt sodium vapor lamp (Area Lighting)		
08/01/2012 through 5/31/2013	46	10.21
06/01/2013 through 5/31/2014	46	11.63
06/01/2014 through 5/31/2015	46	13.19
06/01/2015 through 5/31/2016	46	18.31
Effective 06/01/2016	46	18.31
250-Watt sodium vapor lamp (Flood Lighting)		
08/01/2012 through 5/31/2013	98	6.17
06/01/2013 through 5/31/2014	98	7.40
06/01/2014 through 5/31/2015	98	7.40
06/01/2015 through 5/31/2016	98	9.92
Effective 06/01/2016	98	9.92
400-Watt sodium vapor lamp (Flood Lighting**)**		
08/01/2012 through 5/31/2013	156	4.76
06/01/2013 through 5/31/2014	156	4.76
06/01/2014 through 5/31/2015	156	4.76
06/01/2015 through 5/31/2016	156	6.38
Effective 06/01/2016	156	6.38

SERVICES

Outdoor Area Lighting Service (continued)

RIDERS

Bills rendered under this schedule are subject to the following applicable Rider Charges:

Rider A – Tax Adjustment Surcharge
Rider B - Storm Damage Charge
Rider F - Phase II Energy Efficiency and Conservation Charge
Rider G - Smart Meter Technologies Charge
Rider J - Default Service Support Charge
Rider N - Solar Photovoltaic Requirements Charge
Rider P – Non-Utility Generation Charge

DEFAULT SERVICE CHARGES:

The Price to Compare Default Service Charge shall be determined using the applicable Monthly kWh usage, from the preceding chart, multiplied by the Price to Compare Default Service Rate Rider, Rider H, Commercial Customer Class rate.

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

TERM OF CONTRACT:

The initial term of contract shall be not less than three (3) years when installed on existing poles or not less than five (5) years when either a pole is installed for supporting the light or secondary facilities are installed to serve the light.

GENERAL PROVISIONS:

A. All facilities necessary for service under this schedule shall be owned and maintained by the Company, except that at its option the Company may install the light on a pole owned by another utility company, or on a farm center pole owned or used by the Customer. If a light is installed on a farm center pole, the Company may require a satisfactory written agreement releasing the Company of damage claims and to indemnify the Company against claims by others

SERVICES

Outdoor Area Lighting Service (continued)

B. No change in height of existing poles in primary distribution lines shall be made, nor shall additional poles be installed in such lines, for the purpose of installing a light unless Customer elects to pay the Company the cost of such change. If requested by a Customer, Company may, at its option, install a pole for supporting a light, and external secondary facilities to such pole, and in such cases there shall be a charge of Six Dollars and Ninety-Two Cents ($6.92) per pole and secondary facilities per month. Not more than two (2) one-pole extensions, or one (1) two-pole extension, may be made per Customer at any single premises. In either case, the extensions may be made only if a light is installed on each pole installed. If requested by a Customer, the Company may, at its option, install secondary

C. Facilities to serve a light, and in such cases, there shall be a charge issued to the Customer by the Company of Six Dollars and Ninety-Two Cents ($6.92) per light per month. As an alternative to the charges stated herein, the Customers may pay to the Company the cost of furnishing and installing the required facilities. For facilities to be installed hereunder, the Customer shall grant such right-of-way as is required, in accordance with the Provisions of this Tariff of this Tariff. The Customer shall obtain satisfactory written approval from the appropriate public authorities for lights to be located on public thorough-fares.

D. The lamp, luminaire with open refractor, and bracket not over four (4) feet in length adopted by the Company as standard for this type of service shall be used. Lamps shall be lighted from dusk to dawn by automatic control furnished by Company and burning hours of the light shall be approximately 4,200 hours per year. Lamp renewals shall be made during normal weekday working hours, ordinarily within forty-eight (48) hours of notification by the Customer, such renewals not to be made on Saturdays, Sundays or holidays.

E. Lights and poles shall be placed only at locations accessible for installation and maintenance by Company’s mechanized equipment.

A mercury vapor light fixture that becomes inoperable will be replaced with an equivalent lumen output sodium vapor light fixture to comply with the Federal Energy Policy Act of 2005 that prohibits the import or manufacture of mercury vapor ballasts. When such replacement occurs, sodium vapor rates will apply based on the Company’s current electric service Tariff.

RIDERS

RIDER A
TAX ADJUSTMENT SURCHARGE RIDER

After the addition of the charges provided in other applicable Riders, a Tax Adjustment Surcharge of (0.00%) shall be applied effective for service rendered on and after October 3, 2014 in addition to all other billings calculated under the provisions of this Tariff.

The Tax Adjustment Surcharge will be recomputed using the elements prescribed by the Commission in its regulations at 52 Pa. Code §69.51, et seq. and at 52 Pa. Code §54.91, et seq.:

1. on December 21 of each year until the surcharge is rolled into base rates, or

2. whenever the Company experiences a material change in any of the taxes used in calculation of the surcharge due to any changes in its state tax liability arising under 66 Pa. C.S. §§ 2806(g), 2809(c) or 2810.

The recalculation will be submitted to the Commission within ten (10) days after the occurrence of the event which occasions such recomputation or as prescribed in the Commission's regulations at 52 Pa. Code §54.91, et seq. If the recomputed surcharge is less than the one in effect, the Company will, or if the recomputed surcharge is more than the one in effect the Company may, submit with such recomputation a tariff or supplement to reflect such recomputed surcharge. The effective date of such tariff or supplement shall be ten (10) days after the filing or as prescribed in the Commission's regulations at 52 Pa. Code §54.91, et seq.

RIDERS

RIDER B
STORM DAMAGE CHARGE RIDER

A Storm Damage Charge ("SDC") shall be applied to each kilowatt-hour ("kWh") delivered during a billing month to all retail Customers served under this Tariff determined to the nearest one-thousandth of a cent per kWh. The SDC shall be non-bypassable.

The SDC charge per Customer Class is as follows:

SDC Customer Class 1 (Rate RS and Rate GS-Volunteer Fire Company, and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service)

0.000 cents per kWh

SDC Customer Class 2 (Rate GS-Small, Rate GS-Medium, Rate GS-Large, Rate MS, Borderline Service, Street Lighting Service, Ornamental Street Lighting Service, LED Street Lighting Service and Outdoor Lighting Service)

0.000 cents per kWh

SDC Customer Class 3 (Rate GP)

0.000 cents per kWh

SDC Customer Class 4 (Rate TP)

0.000 cents per kWh

The SDC shall be calculated in accordance with the formula set forth below:

$$SDC = \{[SDC_{CCA} \times (SD_C - SD_B - E)] / S_C\} \times [1/(1-T)]$$

Where:

SDC = The Customer Class charge in mills per kWh to be applied to each kWh of retail sales for the Customer Class, delivered to retail Customers served under this Tariff.

SDC_{CCA} = The SDC Customer Class Allocation Factors set forth in Table 1 of this rider.

RIDERS

RIDER B (continued)

SD_C = Storm Damage Costs, which are the direct, indirect and administrative costs (including wages and administration) incurred by the Company to provide storm damage restoration for the SDC Reconciliation Year, for the following activities and work:

- Pole replacements
- Line reconstruction
- All other services and equipment necessary to be performed and/or installed by the Company and/or its contractors to restore service to Customers following a storm.

SDC Customer Class Allocation Factors will be determined based on the Company's most recent Cost of Service Study.

SD_B = The amount of Storm Damage Costs currently reflected in the Company's most recent base rate case.

E = The over or under-collection of Storm Damage Costs that result from the billing of the SDC during the SDC Reconciliation Year (an over-collection is denoted by a positive E and an under-collection by a negative E) including applicable interest. Interest shall be computed monthly, based upon 41. P. S. § 202, the legal rate of interest, from the month the over or under-collection occurs to the month that the over-collection is refunded to or the under-collection is recovered from Customers.

S_C = The Company's projected Customer Class retail kWh sales for the projected SDC billing period.

T = The Pennsylvania gross receipts rate in effect during the billing month expressed in decimal form as reflected in the Company's base rates.

Table 1

SDC Customer Class	Allocation Factors
SDC Customer Class 1	.70992
SDC Customer Class 2	.20031
SDC Customer Class 3	.07900
SDC Customer Class 4	.01077

RIDERS

RIDER B (continued)

All capitalized terms not otherwise defined in this Rider shall have the definitions specified in Definition of Terms section of this Tariff. For purposes of this Rider, the following additional definitions shall apply:

1. SDC Computational Year - the 12 month period from January 1 through December 31 of each calendar year.

2. SDC Reconciliation Year - the period from November 1 through October 31 immediately preceding the SDC Computational Year.

3. SDC Interim Period – the period from the effective date of this rider through October 31, 2015.

The SDC shall be filed with the Commission by December 1 of each year. The SDC shall become effective the following January 1, unless otherwise ordered by the Commission, and shall remain in effect for a period of one year, unless revised on an interim basis subject to the approval of the Commission. Upon determination that the SDC charges, if left unchanged, would result in material over or under-collection of all Storm Damage Costs incurred or expected to be incurred during the current 12-month period ending December 31, the Company may request the Commission for interim revisions to the SDC to become effective thirty (30) days from the date of filing, unless otherwise ordered by the Commission.

At the conclusion of the period that this rider is in effect, the Company shall be authorized to recover or refund any reconciliations to be applied to Customer's bills under such mechanism the Commission may approve.

The SDC shall be subject to review and audit by the Commission.

RIDERS

RIDER C
UNIVERSAL SERVICE COST RIDER

Universal Service Charge ("USC") shall be applied to each kilowatt-hour delivered during a billing month to all Customers served under residential retail rate schedules under this Tariff, determined to the nearest one-thousandth of a cent per kilowatt-hour. The USC shall be non-bypassable.

For services rendered January 1, 2014 through December 31, 2014 the USC shall be equal to .339 cents per kWh for all kWh. The USC shall be included in the distribution charges of the monthly bill.

The USC shall be calculated in accordance with the formula set forth below:

$$USC = [(US_C/S_{Res}) - (E/S_{Res})] \text{ X } [1/(1-T)]$$

Where:

USC = The charge in mills per kilowatt-hour to be applied to each kilowatt-hour delivered to all Customers served under residential retail rate schedules under this Tariff.

US_C = Universal Service Program Costs, which are the estimated direct, indirect and administrative costs to be incurred by the Company to provide Universal Service to Customers for the USC Computational Year for the following programs ("Universal Service Programs"):

- Customer Assistance and Referral for Evaluation of Services ("CARES") Program
- Customer Assistance Program ("CAP")
- Fuel Fund Administration
- Gatekeeper Program
- WARM (formerly LIURP) Program
- Any other replacement or Commission-mandated Universal Service Programs.

S_{Res} = The Company's projected retail kilowatt-hour sales for the projected USC billing period for Customers served under residential retail rate schedules under this Tariff.

RIDERS

Rider C (continued)

E = The over or under-collection of Universal Service Program costs that result from the billing of the USC during the USC Reconciliation Year (an over-collection is denoted by a positive E and an under-collection by a negative E), including applicable interest. Interest shall be computed monthly as provided for in 41 P.S. § 202, the legal statutory interest rate, from the month the over or under-collection occurs to the month that the over-collection is refunded to or the under-collection is recovered from Customers.

T = The Pennsylvania gross receipts rate in effect during the billing month expressed in decimal form as reflected in the Company's base rates.

All capitalized terms not otherwise defined in this Rider shall have the definitions specified in Section 2 of this Tariff. For purposes of this Rider, the following additional definitions shall apply:

1. USC Computational Year - the 12 month period from January 1 through December 31 of each calendar year.

2. USC Reconciliation Year - the period from November 1 through October 31 immediately preceding the USC Computational Year.

The USC shall be filed with the Commission by December 1 of each year. The USC shall become effective the following January 1, unless otherwise ordered by the Commission, and shall remain in effect for a period of one year, unless revised on an interim basis subject to the approval of the Commission. Upon determination that the USC rates, if left unchanged, would result in material over or under-collection of all Universal Service Program Costs incurred or expected to be incurred during the current 12-month period ending December 31, the Company may request the Commission for interim revisions to the USC to become effective thirty (30) days from the date of filing, unless otherwise ordered by the Commission.

The Company shall file a report of collections under the USC within forty-five (45) days following the conclusion of each Computational Year quarter.

The USC shall be subject to review and audit by the Commission.

RIDERS

RIDER D
NET METERING RIDER

PURPOSE:

This Rider sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

APPLICABILITY:

This Rider applies to renewable customer-generators served under Rate Schedules RS, GS-Volunteer Fire Company and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate, GS-Small, GS-Medium, GS-Large, GP, TP and MS who install a device or devices which are, in the Company's judgment, subject to Commission review, a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system. This Rider is available to installations where any portion of the electricity generated by the renewable energy generating system offsets part or all of the customer-generator's requirements for electricity. A renewable customer-generator is a non-utility owner or operator of a net metered generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service (Rate RS) or not larger than 3,000 kilowatts at other customer service locations (Rate GS-Volunteer Fire Company and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate ,GS-Small, GS-Medium, GS-Large, GP, TP and MS), except for Customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the Company during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the purpose of maintaining critical infrastructure such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities provided that technical rules for operating generators interconnected with facilities of the Company have been promulgated by the Institute of Electrical and Electronic Engineers ("IEEE") and the Commission.

Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. This Rider is not applicable to Customers served under Borderline Service, Partial Service, Rate Schedule QF, any Lighting Rate Schedules or any Customers utilizing Station Power Energy Netting.

RIDERS

Rider D (continued)

Service under this Rider is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule RS, GS-Volunteer Fire Company and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate, GS-Small, GS-Medium, GS-Large, GP, TP and MS.

1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

2. If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

Additional metering equipment for the purpose of qualify customer-generator. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The company shall, prior to taking title to any alternate energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer–generator for their disposition.

RIDERS

Rider D (continued)

3. Meter aggregation on properties owned or leased and operated by a customer-generator shall be allowed for purposes of net metering. Meter aggregation shall be limited to meters located on properties within two (2) miles of the boundaries of the customer-generator's property. Meter aggregation shall only be available for properties located within the Company's service territory. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis.

BILLING PROVISIONS:

The following billing provisions apply to customer-generators in conjunction with service under applicable Rate Schedule RS, GS-Volunteer Fire Company and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate, GS-Small, GS-Medium, GS-Large, GP, TP and MS.

1. The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate, consistent with Commission regulations. On an annual basis, the Company will compensate the customer-generator for kilowatt-hours received from the customer-generator in excess of the kilowatt hours delivered by Company to the customer-generator during the preceding year at the "full retail value for all energy produced" consistent with Commission regulations. The customer-generator is responsible for the distribution charge, demand charge and other applicable charges under the applicable Rate Schedule.

2. If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the distribution charge, demand charge and other applicable charges under the applicable Rate Schedule.

RIDERS

Rider D (continued)

3. For customer-generators involved in virtual meter aggregation programs, a credit shall be applied first to the meter through which the generating facility supplies electricity to the distribution system, then through the remaining meters for the customer-generator's account equally at each meter's designated rate. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the distribution charge, demand charge and other applicable charges under the applicable Rate Schedule.

4. If a net metering Customer served on Rate GS-Volunteer Fire Company and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate, GS-Small, GS-Medium, GS-Large, GP, TP and MS generates electricity such that the self-generation results in a 10% or more reduction in the customer's purchase of electricity through the Company's transmission and distribution network for any calendar year when compared to the calendar year immediately prior to the installation of the generation, the net metering Customer shall be responsible for its share of stranded costs to prevent interclass or intraclass cost shifting. The Company, upon determination that the customer has or will exceed the 10% limitation, will rebill the customer for NUG Charges, in an amount equal to the charges in the calendar year immediately prior to the installation of the generation. Such rebilling of NUG Charges will be at the otherwise applicable NUG Charge rate.

APPLICATION:

Customer-generators seeking to receive service under the provisions of this Rider must submit a written application to the Company demonstrating compliance with the Net Metering Rider provisions and quantifying the total rated generating capacity of the customer-generator facility.

RIDERS

Rider D (continued)

MINIMUM CHARGE:

The Minimum Charges under Rate Schedule RS, GS-Volunteer Fire Company and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate, GS–Small, GS-Medium, GS-Large, GP, TP and MS apply for installations under this Rider.

RIDERS:

Bills rendered by the Company under this Rider shall be subject to charges stated in any other applicable Rider

RIDERS

RIDER E
EMERGENCY ENERGY CONSERVATION RIDER

PURPOSE:

This Rider is applicable to Customers in conjunction with Tariff Rule 18, relating to Load Control. It provides for deviation from and modifications to the charges and practices otherwise applicable to certain Customers as a result of compliance with or non-compliance with emergency energy conservation levels ordered under conditions resulting from actual or potential shortage of fuel for electric generation.

APPLICABILITY:

Applicable to individual electric Customer accounts served under Rate Schedules GP and TP with measured demand of 2,000 KW or higher, in a recent twelve (12) month period prior to the order for emergency energy conservation. Customers designated by the provisions of Tariff Rule 19 and by the Pennsylvania Public Utility Commission will be exempt from the Provisions of this Rider.

PROVISIONS:

Base period energy use - The base energy use for a weekly period shall be determined by the Company for each applicable electric Customer account based upon a consideration of the Customer's actual past or current electric consumption and the Customer's existing operations.

Energy use level target - The energy use level target for each applicable Customer shall be that percentage of base period energy use ordered pursuant to the emergency energy conservation procedures provided by Tariff Rule 19 or other percentage as result of the order of appropriate governmental authority.

Current energy use - Current period use will be monitored on a weekly basis commencing no later than seventy-two (72) hours after the emergency is declared.

Compliance - When the energy consumption in any weekly period during the period of the emergency energy conservation condition is equal to or less than the energy use level target, the Customer will be deemed to have complied.

RIDERS

Rider E (continued)

Non-compliance - When the energy consumption in any weekly period during the period of emergency energy conservation condition exceeds the energy use target level, the Customer will be deemed in non-compliance.

In the event of continued non-compliance, the Company, upon notice to the Commission, may discontinue service.

Billing - During the period of emergency energy conservation condition, billing will be based on meter readings especially made to identify the demand established and energy used during the current energy use period. Customers in compliance with conservation orders will be excused from minimum bills and historical or contract demand or ratchet provisions and will be billed instead on the basis of current consumption and demand whenever the normal calculation method would produce a greater bill.

These Customers will be individually notified of this special billing provision prior to the implementation of the emergency energy conservation procedure.

RIDERS

RIDER F
PHASE II ENERGY EFFICIENCY AND CONSERVATION CHARGE RIDER

A Phase II Energy Efficiency and Conservation Charge ("Phase II EE&C-C") shall be applied to each Billing Unit during a billing month to Customers served under this Tariff, with the exception of those served under Borderline Service rates. Billing Units are defined as follows:

Residential, Non-profit, Commercial, and Street Lighting Customer Classes:	Per kWh
Industrial Customer Class:	Per kW PLC

Residential, Non-profit, Commercial, and Street Lighting Customer Class rates will be calculated to the nearest one-thousandth of a cent per kWh. Industrial Customer Class rates will be calculated to the nearest one-hundredth of a dollar per kW PLC. The Phase II EE&C-C rates shall be calculated separately for each Customer Class according to the provisions of this rider. For Residential Customers, the Phase II EE&C-C shall be included in the distribution charges of the monthly bill. For all other Customers, the Phase II EE&C-C shall be listed as a separate charge on the monthly bill.

For service rendered June 1, 2014 through May 31, 2015 the Phase II EE&C-C rates billed by Customer Class are as follows:

Residential Customer Class (Rate RS):

0.242 cents per kWh.

Non-profit Customer Class (Rate GS – Volunteer Fire Company, and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate and Rate MS):

0.774 cents per kWh.

Commercial Customer Class (Rate GS-Small, Rate GS-Medium, and Outdoor Lighting Service):

0.086 cents per kWh.

Street Lighting Customer Class (Street Lighting Service, LED Street Lighting Service and Ornamental Street Lighting Service):

0.017 cents per kWh.

Industrial Customer Class (Rate GS-Large, Rate GP, and Rate TP):

$ 0.19 per kW PLC.

RIDERS

Rider F (continued)

The Phase II EE&C-C rates by Customer Class shall be calculated in accordance with the formula set forth below:

$$EEC\text{-}C = [(EEC_C - E) / S] \text{ X } [1 / (1 - T)]$$

$$EEC_C = EEC_{Exp1} + EEC_{Exp2} + EEC_{Exp3} + EEC_{Exp4}$$

Where:

EEC-C = The charge in cents or dollar per Billing Unit by Customer Class as defined by this rider applied to each Billing Unit for the Rate Schedules identified in this rider.

EEC_C = The Energy Efficiency and Conservation Costs by Customer Class incurred and projected to be incurred by the Company for the Phase II EE&C-C Computational Period calculated in accordance with the formula shown above.

EEC_{Exp1} = Costs incurred and projected to be incurred associated with the Customer Class specific Phase II EE&C Programs as approved by the Commission for the Phase II EE&C-C Computational Period by Customer Class. These costs also include an allocated portion of any indirect costs incurred associated with all the Company's Phase II EE&C Programs for the Phase II EE&C-C Computational Period. Such costs shall be allocated to each Customer Class based on the ratio of class-specific approved budgeted program costs to total approved budgeted program costs.

EEC_{Exp2} = An allocated portion of incremental administrative start-up costs incurred by the Company through May 31, 2013 in connection with the development of the Company's Phase II EE&C Programs in response to the Commission's orders and guidance at Docket Nos. M-2012-2289411 and M-2008-2069887. These costs to design, create, and obtain Commission approval for the Company's Phase II EE&C Programs include, but are not limited to, consultant costs, legal fees, and other direct and indirect costs associated with the development and implementation of the Company's Phase II EE&C Programs in compliance with Commission directives. Such costs shall be allocated to each Customer Class based on the ratio of class-specific approved budgeted program costs to total approved budgeted program costs.

RIDERS

Rider F (continued)

EEC_{Exp3} = An allocated portion of the costs the Company incurs and projects to incur to fund the Commission's statewide evaluator contract which shall be excluded in the final determination of the Act 129 limitation on the Company's Phase II EE&C Programs costs. Such costs shall be allocated to each Customer Class based on the ratio of class-specific approved budgeted program costs to total approved budgeted program costs.

EEC_{Exp4} = An allocated portion of any costs the Company incurs and projects to incur to fund any future Commission-approved demand response programs, or successor demand response programs. Such costs shall be allocated to each Customer Class based on the ratio of class-specific approved budgeted program costs to total approved budgeted program costs.

E = The cumulative over or under-collection of Phase II EE&C costs by Customer Class that results from the billing of the Phase II EE&C-C rates (an over-collection is denoted by a positive E and an under-collection by a negative E).

S = The Company's projected Billing Units (kWh sales delivered to all Customers in the specific Customer Class or kW PLC demand for the Industrial Customer Class).

T = The Pennsylvania gross receipts tax rate in effect during the billing month expressed in decimal form as reflected in the Company's base rates.

All capitalized terms not otherwise defined in this rider shall have the definitions specified in the Definitions of Terms section of this Tariff. For the purpose of this Rider, the following additional definitions shall apply:

RIDERS

Rider F (continued)

1. Phase II EE&C-C Computational Period – The 12-month period from June 1, 2013 through May 31, 2014.

2. Phase II EE&C-C Initial Reconciliation Period – June 1, 2013 through March 31, 2014 for the initial period of the rider.

3. Phase II EE&C-C Reconciliation Period – The 12-month period ending March 31 each year thereafter, except for the Initial Reconciliation Period, for the duration of this rider.

4. Peak Load Contribution ("PLC") – A Customer's contribution to the Company's transmission zone normalized summer peak load, as estimated by the Company in accordance with PJM rules and requirements.

The Company will submit to the Commission by May 1 of each year starting May 1, 2014: (1) a reconciliation between actual Phase II EE&C-C revenues and actual Phase II EE&C-C costs through March of that year, as adjusted for removal of gross receipts tax; (2) any adjustment to the forecasted Phase II EE&C-C revenues anticipated to be billed during April through May of that year, as adjusted for removal of gross receipts tax; (3) any adjustment to the Phase II EE&C costs based upon actual costs incurred through March and any revised estimates for future months (including, but not limited to, re-evaluation or re-design of Phase II EE&C Programs and re-allocation of Phase II EE&C Program Costs to the designated Rate Schedules), subject to the amount permitted to be recovered under 66 Pa.C.S. § 2806.1; (4) the subsequent effect of the EE&C cost adjustment, Billing Unit forecast update, and reconciliation to the Phase II EE&C-C rates adjusted for gross receipts tax, and levelized over the period of the upcoming June 1 and continuing through the following May 31; (5) the Phase II EE&C budget estimate for the forthcoming annual calculation period (June 1 through May 31) by rate class; and (6) any other changes or adjustments approved by the Commission pertaining to the implementation of the Phase II EE&C Plan. There shall also be a final reconciliation of amounts to be collected or refunded after May 31, 2016.

Upon determination that the Phase II EE&C-C rates, if left unchanged, would result in material over or under-collection of all recoverable costs incurred or expected to be incurred by Customer Class, the Company may request that the Commission approve one or more interim revisions to the Phase II EE&C-C rates to become effective thirty (30) days from the date of filing, unless otherwise ordered by the Commission.

RIDERS

Rider F (continued)

The Company shall file an annual report of collections under this rider by June 30th of each year starting June 30, 2014 until the conclusion of this rider.

At the conclusion of the duration of this rider, the Company is authorized to recover or refund any remaining amounts not reconciled at that time under such mechanism as approved by the Commission.

Application of the Phase II EE&C-C rates shall be subject to annual review and audit by the Commission.

RIDERS

RIDER G
SMART METER TECHNOLOGIES CHARGE RIDER

A Smart Meter Technologies ("SMT") Charge ("SMT-C") shall be applied as a monthly Customer charge during each billing month to metered Customers served under this Tariff, with the exception of those served under Borderline Service rates, determined to the nearest cent. The SMT-C rates shall be calculated separately for each Customer Class according to the provisions of this rider. For all Customers, the SMT-C shall be included in the distribution charges of the monthly bill.

For service rendered July 1, 2014 through December 31, 2014 the SMT-C rates billed by Customer Class are as follows:

Residential Customer Class (Rate RS and Rate GS – Volunteer Fire Company, and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate):

$2.40 per month.

Commercial Customer Class (Rate GS-Small, Rate GS-Medium, and Rate MS):

$2.36 per month.

Industrial Customer Class (Rate GS-Large, Rate GP, and Rate TP):

$2.33 per month

RIDERS

Rider G (continued)

The SMT-C rates by Customer Class shall be calculated in accordance with the formula set forth below:

$$SMT\text{-}C = [((SMT_C - E) / ACCC) / 12] \text{ X } [1 / (1 - T)]$$

$$SMT_C = SMT_{Exp1} + SMT_{Exp2}$$

Where:

SMT-C = The monthly charge by Customer Class as defined by this rider applied to each Customer billed under the Rate Schedules identified in this rider.

SMT_C = The Smart Meter Technologies Costs by Customer Class projected to be incurred by the Company for the SMT-C Computational Year calculated in accordance with the formula shown above.

SMT_{Exp1} = A projection of costs to be incurred associated with the Customer Class specific Smart Meter Technology Procurement and Installation Plan ("Plan") as approved by the Commission for the SMT-C Computation Year by Customer Class including carrying charges on capital costs, depreciation expense, and operational and maintenance expenses. These costs would also include an allocated portion of any projected indirect costs to be incurred benefiting all Customer Classes of the Company's Plan for the SMT-C Computational Year. Any reduction in operating expenses or avoided capital expenditures due to the Smart Metering Program will be deducted from the incremental costs of the Smart Meter Program to derive the net incremental cost of the Program that is recoverable. Such reductions shall include any reductions in the Company's current meter and meter reading costs.

RIDERS

Rider G (continued)

SMT_{Exp2} = An allocated portion of incremental administrative start-up costs incurred by the Company through July 31, 2010 in connection with the development of the Company's Plan. These costs to design, create, and obtain Commission approval for the Company's Plan include, but are not limited to, consultant costs, legal fees, and other direct and indirect costs associated with the development and implementation of the Company's Plan in compliance with Commission directives. These costs shall be amortized over the 5-month period ending December 31, 2010. Interest will be calculated monthly on the average of the beginning and end of month cumulative balance of these costs as incurred and included in the determination of the monthly amortized amount. The interest shall be computed based on the legal rate determined pursuant to 41 P.S. § 202.

E = The over or under-collection of SMT costs by Customer Class that results from the billing of the SMT-C rates during the SMT Reconciliation Year (an over-collection is denoted by a positive E and an under-collection by a negative E), including applicable interest. Interest shall be computed monthly at the legal rate determined pursuant to 41 P.S. § 202, from the month the over or under-collection occurs to the month that the over-collection is refunded or the under-collection is recovered from Customers in the specific Customer Class. Any reduction in operating expenses or avoided capital expenditures due to the Smart Metering Program will be deducted from the incremental costs of the Smart Meter Program to derive the net incremental cost of the Program that is reconciled to the billed SMT-C rates during the SMT Reconciliation Year. Such reductions shall include any reductions in the Company's current meter and meter reading costs.

RIDERS

Rider G (continued)

ACCC= The Company's projected Average Customer Class Count for the specific Customer Class for the SMT-C Computational Year.

T = The Pennsylvania gross receipts tax rate in effect during the billing month expressed in decimal form as reflected in the Company's base rates.

All capitalized terms not otherwise defined in this rider shall have the definitions specified in the Definitions of Terms section of this tariff. For the purpose of this rider, the following additional definitions shall apply:

1. SMT-C Computational Year – The 12-month period from January 1 through the following December 31 with the exception of the initial SMT-C Computational Year that will be the 5-month period from August 1, 2010 through December 31, 2010.

2. SMT-C Reconciliation Year – The 12-month period ending June 30 immediately preceding the SMT-C Computational Year.

The initial SMT-C rates pursuant to this rider shall be effective August 1, 2010 through December 31, 2010. Subsequent SMT-C rates shall be filed with the Commission by August 1 of each year and the SMT-C rates shall become effective the following January 1, unless otherwise ordered by the Commission, and shall remain in effect for a period of one year, unless revised on an interim basis subject to the approval of the Commission. Upon determination that the SMT-C rates, if left unchanged, would result in material over or under-collection of all recoverable costs incurred or expected to be incurred during the then-current SMT-C Computational Year, the Company may request that the Commission approve one or more interim revisions to the SMT-C rates to become effective thirty (30) days from the date of filing, unless otherwise ordered by the Commission.

RIDERS

Rider G (continued)

The Company shall file an annual report of collections under this rider within thirty (30) days following the conclusion of each SMT-C Reconciliation Year.

At the conclusion of the duration of this reconciliation rider, the Company is authorized to recover or refund any remaining amounts not reconciled at that time under such mechanism as approved by the Commission.

Application of the SMT-C rates shall be subject to annual review and audit by the Commission

RIDERS

RIDER H
PRICE TO COMPARE DEFAULT SERVICE RATE RIDER

A Price to Compare Default Service Rate ("$PTC_{Default}$") shall be applied to each kWh of Default Service that Met-Ed delivers to Customers under this rider as determined to the nearest one-thousandth of a cent per kWh. The $PTC_{Default}$ rate shall be billed to Customers receiving Default Service from the Company under this rider. The rates shall be calculated according to the provisions of this rider.

For service rendered September 1, 2014 through November 30, 2014 the $PTC_{Default}$ rates billed by Customer Class are as follows:

Commercial Customer Class (Rate GS-Small, Rate GS-Medium, Rate MS, Borderline Service, Street Lighting Service, Ornamental Street Lighting, LED Street Lighting Service and Outdoor Lighting Service):

$0.06715 per kWh.

Residential Customer Class (Rate RS, Rate RT, and Rate GS – Volunteer Fire Company, Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate):

$0.07362 per kWh

RIDERS

Rider H (continued)

The $PTC_{Default}$ rates by Commercial or Residential Customer Class will be calculated at the end of each Default Service Quarter (three months ending March 31st, June 30th, September 30th, and December 31st) to be effective for the three-month period beginning on the first day of the third calendar month following the end of that Default Service Quarter (June 1st, September 1st, December 1st, and March 1st). The $PTC_{Default}$ rate shall be calculated by Customer Class in accordance with the formula set forth
below:

$$PTC_{Default} = [(PTC_{Current} + E)] \text{ X } [1 / (1 - T)]$$

$$PTC_{Current} = (PTC_{Current\ Cost\ Component} \text{ X } PTC\ Loss_{Current}) + PTC_{Adm} + PTC_{NITS}$$

$$E = [((DS_{Exp1} + DS_{Exp2}) - PTC_{Rev} + DS_{Int})/DS_{Sales}] \quad (C)$$

Where:

$PTC_{Current}$ = The current cost component of the $PTC_{Default}$ rate grossed up for line losses calculated by Commercial or Residential Customer Class determined to the nearest one-thousandth of a cent per kWh to be applied to each kWh of Default Service delivered to Retail Customers under this rider.

The computation of the $PTC_{Current}$ component of the $PTC_{Default}$ rate by Commercial or Residential Customer Class will use the following procedures:

$PTC_{Current\ Cost\ Component}$ = The current cost component of the $PTC_{Default}$ rate calculated by Customer Class determined to the nearest one-thousandth of a cent per kWh to be applied to each kWh of Default Service delivered to Retail Customers under this rider. This rate will be determined, by Customer Class, using the projected weighted cost of Default Service supply acquired by the Company to serve Default Service load and will include any AEPS expenses that may be incurred by the Company related to amendments to the AEPS Act that may occur subsequent to the effective date of the Supplier Master Agreement for the Default Service Supply Plan. The cost of Default Service supply will include the costs the Company incurs from any block and spot purchases as required by the terms of the Default Service Supply Plan.

RIDERS

Rider H (continued)

PTC $Loss_{Current}$ = Distribution line losses for energy that are determined by the applicable Loss Factors specified below:

Customer Class	Loss Factor
Commercial Customer Class	1.0515
Residential Customer Class	1.0515

PTC_{Adm} = An administrative fee for applicable administration costs by Customer Class determined to the nearest one-thousandth of a cent per kWh to be applied to each kWh of Default Service delivered to Retail Customers under this rider.

PTC_{NITS} = For the Residential Customer Class only, a Network Integration Transmission Service charge for block energy purchases, determined to the nearest one-thousandth of a cent per kWh to be applied to each kWh of Default Service delivered to Retail Customers under this rider.

E = The Price to Compare Default Service Reconciliation Rate component by Customer Class. The rate determined to the nearest one-thousandth of a cent per kWh by Customer Class shall be applied to each kWh of Default Service delivered to retail Customers by Customer Class under this rider.

RIDERS

Rider H (continued)

DS_{Exp1} = An allocated portion of the incremental start-up costs incurred by the Company through May 31, 2013 in connection with the Company's Default Service Supply Plan to provide Default Service amortized over the twenty-four (24) month period ending May 31, 2015, including but not limited to:

- Incremental start-up administrative costs including metering and billing costs incurred and other costs as necessary to provide service to retail Default Service Customers
- Other start-up costs incurred to develop and implement the competitive bid process for the retail Default Service Supply Plan for retail Default Service including legal, customer notice, and consultant fees
- The incremental administrative start-up costs associated with the portfolio procurements of the supply needed from block and spot purchases

Interest will be calculated monthly on the average of the beginning and the end of month balances of these costs and included in the determination of the monthly amortized amount. The monthly interest rate will be based upon the 41 P.S. § 202 statutory rate.

DS_{Exp2} = The cumulative costs to provide Default Service incurred by the Company for the respective Customer Class through the end of the previous Default Service Quarter, including but not limited to the following:

RIDERS

Rider H (continued)

- Payments made to winning bidders
- Any net energy costs associated with the portfolio procurements of the supply needed from block and spot purchases. These net energy costs will reflect the net proceeds from sales in the wholesale energy market of any excess energy purchased by the Company to provide Default Service that exceeds actual energy used.).
- Any PJM related charges including capacity, operating reserve, transmission-related costs other than Non-Market Based Services Transmission Charges, and ancillary services associated with the portfolio procurements of the supply needed from block and spot purchases.
- An allocated portion of administrative costs associated with the portfolio procurements of the supply needed from block and spot purchases.
- An allocated portion of incremental administrative costs including metering and billing costs incurred and other costs as necessary to provide service to retail Default Service Customers.
- All contingency plan implementation costs incurred during the supply period.
- An allocated portion of other costs incurred to develop and implement the competitive bid process for Retail Default Service including legal, customer notice, and consultant fees.
- AEPS expenses incurred by the Company related to amendments to the AEPS Act occurring subsequent to the effective date of the Supplier Master Agreement for the Default Service Supply Plan excluding such costs that are recovered through the Company's Solar Photovoltaic Requirements Charge Rider.

RIDERS

Rider H (continued)

- The net AEPS expenses incurred by the Company associated with the portfolio procurements of the supply needed from block and spot purchases. These net AEPS expenses will reflect the net proceeds of sales of AEPS credits purchased that exceed the AEPS credits needed to meet AEPS requirements.
- The cost of credit when the Company is considered by PJM to be the load serving entity

PTC_{Rev} = The cumulative revenues billed to Retail Customers by Customer Class for Default Service under the Default Service Supply Plan, excluding applicable Pennsylvania gross receipts tax, through the end of the most recent Default Service Quarter billed under the respective Customer Class $PTC_{Default}$ rates.

DS_{Int} = The cumulative amount of carrying charges calculated on a monthly basis through the end of the most recent Default Service Quarter by Customer Class. Interest will be calculated monthly on the average balance of 1) the respective month's beginning balance of prior months' cumulative over or under collection of PTC_{Rev} compared to the sum of the amortized portion of DS_{Exp1} costs and DS_{Exp2} costs incurred to date including

RIDERS

Rider H (continued)

cumulative interest calculated thereon through the beginning of the month; and 2) the respective month's ending balance of cumulative over or under collection of PTC_{Rev} compared to the amortized portion of DS_{Exp1} costs and DS_{Exp2} costs incurred to date including cumulative interest calculated thereon through the beginning of the month. The monthly interest rate will be based upon the 41 P.S. § 202 statutory annual rate for under collections and based upon the 41 P.S. § 202 statutory annual rate plus two percent for (over) collections.

DS_{Sales} = The Company's projected Default Service kWh sales to Retail Customers by Customer Class for the three-month billing period that the E rate component of the $PTC_{Default}$ rate will be in effect.

T = The Pennsylvania gross receipts tax rate in effect during the billing month expressed in decimal form as reflected in the Company's base rates.

Each change in the $PTC_{Default}$ rates will be filed with the Commission thirty (30) days prior to the effective date of the rate changes. The Company shall file details in support of the revised $PTC_{Default}$ rates.

At the conclusion of the duration of this reconciliation rider, the Company is authorized to recover or refund any remaining amounts not reconciled at that time under such mechanism as approved by the Commission.

Application of the $PTC_{Default}$ rates shall be subject to annual review and audit by the Commission.

RIDERS

RIDER I
HOURLY PRICING DEFAULT SERVICE RIDER

AVAILABILITY:

The charges billed under this rider are applicable to all Customers on Rate Schedules GS-Large, GP, and TP who elect to take Default Service from the Company. These charges are also applicable to Customers on Rate Schedules GS-Small and GS-Medium on a voluntary basis who meet the metering requirements of this rider. Rates shall be billed under this rider on the next scheduled meter reading date after electing Default Service.

All GS-Small and GS-Medium Customers electing service under this rider must have Smart Meter technology installed as part of the Company's Smart Meter Plan filed with and approved by the Commission.

Hourly Pricing Service Charges:

Customers participating in the Hourly Pricing Default Service Rider will be billed for usage based on the following calculation:

Hourly Pricing Service Charges = ($HP_{\text{Energy Charge}} + HP_{\text{Cap-AEPS-Other Charge}} + HP_{\text{Administrative Charge}} + HP_{\text{Unc}} + HP_{\text{Reconciliation Charge}}$) X [1 / (1-T)]

HP Energy Charge per kWh:

$$HP_{\text{Energy Charge}} = \sum_{t=1}^{n} (kWh_t \times (LMP_t + HP_{Anc}) \times HP_{\text{Loss Multiplier}})$$

Where:

n = Total number of hours in the billing period

t = An hour in the billing period

LMP = the "Real Time" PJM load-weighted average Locational Marginal Price for the ME Transmission Zone.

HP_{Anc} = $0.00200 per kWh for ancillary services

RIDERS

Rider I (continued)

HP Loss Multipliers:	GS-Small	1.0515
	GS-Medium	1.0515
	GS-Large	1.0515
	GP	1.0171
	TP	1.0007

These HP Loss Multipliers exclude transmission losses.

HP Cap-AEPS-Other Charge:

$0.01846 per kWh representing the costs paid by the Company to the Supplier for Capacity, AEPS costs, and any other costs incurred by the Supplier multiplied by the HP Loss Multipliers. This charge is subject to quarterly adjustments.

HP Administrative Charge:

$0.00004 per kWh representing the administrative costs incurred by the Company associated with providing Hourly Pricing Service.

HP Uncollectibles Charge:

$0.00001 per kWh representing the generation-related unbundled uncollectible accounts expense associated with Hourly Pricing Default Service. This charge is subject to annual adjustment on June 1 of each year.

RIDERS

Rider I (continued)

HP Reconciliation Charge:

The HP Reconciliation Charge Rate ("E_{HP}") shall be applied to each kWh of Default Service that Met-Ed delivers to Customers under this rider as determined to the nearest one-thousandth of a cent per kWh. The E_{HP} rate shall be included as a non-bypassable component billed to Customers receiving Default Service from the Company under this rider. The rate shall be calculated according to the provisions of this rider.

For service rendered September 1, 2014 through November 30, 2014, the E_{HP} rate is as follows:

HP Reconciliation Charge Rate = $0.02859 per kWh

The E_{HP} rate will be calculated at the end of each Default Service Quarter (three months ending March 31st, June 30th, September 30th, and December 31st) to be effective for the three-month period beginning on the first day of the third calendar month following the end of that Default Service Quarter (June 1st, September 1st, December 1st, and March 1st). The E_{HP} rate shall be calculated in accordance with the formula set forth below:

$$E_{HP} = ((DS_{HPExp1} + DS_{HPExp2}) - PTC_{HPRev} + DS_{HPInt})/DS_{HPSales}$$

Where:

E_{HP} = The rate determined to the nearest one-thousandth of a cent per kWh to be applied to each kWh of Default Service delivered to Customers under this rider.

DS_{HPExp1} = An allocated portion of the incremental start-up costs incurred by the Company through May 31, 2013 in connection with the Company's Default Service Supply Plan to provide Default Service amortized over the twenty-four (24) month period ending May 31, 2015 including but not limited to:

RIDERS

Rider I (continued)

- Incremental start-up administrative costs including metering and billing costs incurred and other costs as necessary to provide service to Retail Default Service Customers
- Other start-up costs incurred to develop and implement the competitive bid process for the Retail Default Service Supply Plan including legal, customer notice, and consultant fees.

Interest will be calculated monthly on the average of the beginning and the end of month balances of these costs and included in the determination of the monthly amortized amount. The monthly interest rate will be based upon the 41 P.S. § 202 statutory rate.

DS_{HPExp2} = The cumulative costs to provide Hourly Pricing Default Service incurred by the Company through the end of the previous Default Service Quarter including but not limited to the following:

- Payments made to winning bidders
- AEPS expenses incurred by Met-Ed related to amendments to the AEPS Act and/or related laws or regulations occurring subsequent to the effective date of the Supplier Master Agreement for the Default Service Supply Plan excluding such costs recovered through the Company's Solar Photovoltaic Requirements Charge Rider
- An allocated portion of incremental administrative costs including metering and billing costs incurred and other costs as necessary to provide service to retail Default Service Customers
- All contingency plan implementation costs incurred during the supply period
- An allocated portion of other costs incurred to develop and implement the competitive bid process for retail Default Service including legal, customer notice, and consultant fees.
- The cost of credit when the Company is considered by PJM to be the load serving entity

RIDERS

Rider I (continued)

PTC_{HPRev} = The cumulative revenues, excluding any revenues associated with the HP Uncollectibles Charge and applicable Pennsylvania gross receipts tax, through the end of the most recent Default Service Quarter billed to Hourly Pricing Default Service Customers under this rider including the applicable E_{HP} rates.

DS_{HPInt} = The cumulative amount of carrying charges calculated on a monthly basis through the end of the most recent Default Service Quarter. Interest will be calculated monthly on the average balance of 1) the respective month's beginning balance of prior months' cumulative over or under collection of PTC_{HPRev} compared to the sum of the amortized portion of DS_{HPExp1} costs and DS_{HPExp2} costs incurred to date including cumulative interest calculated thereon through the beginning of the month; and 2) the respective month's ending balance of cumulative over or under collection of PTC_{HPRev} compared to the amortized portion of DS_{HPExp1} costs and DS_{HPExp2} costs incurred to date including cumulative interest calculated thereon through the beginning of the month. The monthly interest rate will be based upon the 41 P.S. § 202 statutory annual rate for under collections and the 41 P.S. § 202 statutory annual rate plus two percent for (over) collections.

$DS_{HPSales}$ = The Company's projected Hourly Pricing Default Service kWh sales to Retail Customers for the three-month billing period that the E_{HP} rate will be in effect.

Gross Receipts Tax:

T = The Pennsylvania gross receipts tax rate in effect during the billing month expressed in decimal form as reflected in the Company's base rates.

RIDERS

Rider I (continued)

General:

Each change in the E_{HP} rate as well as other rates within this rider will be filed with the Commission thirty (30) days prior to the effective date of the rate changes. The Company shall file details in support of the revised
rates.

At the conclusion of the duration of this reconciliation rider, the Company is authorized to recover or refund any remaining amounts not reconciled at that time under such mechanism as approved by the Commission.

Application of the E_{HP} rate shall be subject to annual review and audit by the Commission.

Adjustment for Meter Location:

Where the Company meters distribution secondary voltage service on the primary side of the transformers, the demand and energy registrations shall each be reduced by two and one-half percent (2.5%). Where the Company meters service supplied at voltages higher than the distribution secondary voltage on the secondary side of the transformers, either compensating - metering equipment will be used to correct for transformer losses or the demand and energy meter registration shall each be increased by two and one-half percent (2.5%).

Metering:

The Customer is responsible for providing a working dedicated telephone line for metering purposes at each metering point or shall pay the Company any and all expenses for providing communications to the interval equipment at the Customer's location(s). Maintenance of the meter(s) will be the responsibility of the Company, which will own the meter(s).

RIDERS

RIDER J
DEFAULT SERVICE SUPPORT RIDER

A Default Service Support ("DSS") rate shall be applied to DSS Sales delivered by the Company to Delivery Service Customers under this rider as determined to the nearest one-thousandth of a cent per kWh or dollar per kW NSPL, as applicable. The DSS rate shall be billed to Customers receiving Delivery Service from the Company under this rider. The DSS rates shall be calculated according to the provisions of this rider. The DSS Rider shall be non-bypassable.

For service rendered during the DSS Initial Computational Period and thereafter, the DSS Computational Year, the DSS rates billed by Rate Schedule are as follows:

Rate Schedule	**DSS Rates**
Rate Schedule RT & GS Volunteer Fire Company and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate – Time-of-Day	(0.266)
Rate Schedule RS & GS Volunteer Fire Company and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate - Non-Time-of-Day	(0.329)
Rate Schedule GS – Small	(0.393)
Rate Schedule GS – Medium	(0.393)
Rate Schedule GS – Large	(0.376)
Rate Schedule GP	(0.353)
Rate Schedule TP	(0.337)
Rate Schedule MS	(0.360)
Rate Schedule OAL	(0.247)
Rate Schedule STLT	(0.248)
Rate Schedule LED Street Lighting Service	(0.248)
Rate Schedule BRD	(0.355)

RIDERS

Rider J (continued)

The DSS rates by rate schedule shall be calculated annually in accordance with the formula set forth below:

$$\text{DSS rate} = [UE + TSC_1 + NMB + RE + CEC] \text{ X } [1 / (1\text{-}T)]$$

The components of the formula are defined below:

Default Service Related Uncollectibles

UE = A default service-related unbundled uncollectible accounts expense charge, determined by Customer Class and stated to the nearest one-thousandth of a cent per kWh, to be applied to DSS Sales delivered by the Company to residential and commercial Delivery Service Customers under this rider. The UE reflects the default service-related portion of the uncollectible account expense based on revenues in the Company's 2014 distribution base rate case and the additional uncollectible accounts expense incurred by the Company as a result of providing Default Service under this tariff. This component of the DSS rate in this non-bypassable rider is non-reconcilable.

The unbundled uncollectible accounts expense associated with Default Service and a purchase of receivables program allocated to Delivery Service Customers on a non-bypassable, non-reconcilable basis will be Customer Class specific and will be adjusted annually on June 1 of each year based on the projected price of Default Service. Adjustments, if necessary, will be made to the uncollectible percentage in a future distribution base rate case or the start of the next Default Service Program, whichever occurs earlier.

The unbundled default service related uncollectibles as determined in the Company's 2014 base rate, combined with the calculated incremental uncollectible accounts expense based on the projected price of Default Service, represents the appropriate fully unbundled non-reconcilable uncollectible accounts expense to be recovered in DSS rates. The calculated incremental uncollectible expense is based on the relationship of uncollectible accounts expense to total revenues for the twelve months ended April 30, 2016, utilizing the income statement in the 2014 distribution base rate case. This ratio is applied to the change in the Company's revenues that would result from the change experienced in default service prices. Incremental uncollectible accounts expense divided by the projected DSS Sales yields an adjustment to the retail price of Default Service supply to be included in DSS rates.

RIDERS

Rider J (continued)

The UE charges by Customer Class to be included in DSS rates are as follows:

Commercial Customer Class (Rate GS-Small, Rate GS-Medium, Rate MS, Borderline Service, Street Lighting Service, Ornamental Street Lighting, LED Street Lighting, and Outdoor Lighting Service):

0.018 cents per kWh

Residential Customer Class (Rate RS, Rate RT, and Rate GS – Volunteer Fire Company, Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate):

0.139 cents per kWh

2006 Deferred Transmission Service Charges

$TSC_1 = [(TSCD – E) / S] X$ Rate Schedule Adjustment Factor

Where:

TSC_1 = The charge to be applied to Delivery Service Customers under this rider to recover the 2006 Transmission Service Charge Deferral ("TSCD"), including carrying charges, which was approved by the Commission in its final order at Docket No. R-00061366, authorizing the Company to amortize such deferral over a 10 year period beginning January 11, 2007 and ending on December 31, 2016. The 10 year amortization of the 2006 TSCD that was not fully recovered under the Transmission Service Charge Rider is being recovered under this DSS Rider which replaced the TSC Rider. The TSC_1 rate will be adjusted on June 1 of each year based on the Company's latest sales forecast available at the time.

TSCD = The balance of the 2006 TSCD including carrying charges, that, as of March 31, 2013 remains to be amortized over the remaining months of the amortization period

RIDERS

Rider J (continued)

E = The over or under-collection of the TSCD that results from billing the TSC_1 during the DSS Reconciliation Year (an over-collection is denoted by a positive E and an under-collection by a negative E), including applicable interest. Interest shall be computed monthly at the legal statutory interest rate stated in 41 P.S. § 202 from the month the over or under-collection occurs to the month that the over-collection is refunded to or the under-collection is recovered from Delivery Service Customers.

S= The Company's total DSS Sales to Delivery Service Customers projected for the DSS Computational Year.

Non-Market Based Services Transmission Charges

$$NMB = (NMB_C - E) / S$$

Where:

NMB = The charge to be applied to Delivery Service Customers served under this rider for Non-Market Based Services Transmission Charge costs incurred by the Company.

NMB_C = Forecasted NMB costs applicable to the Company's DSS Sales. Forecasted NMB costs shall include FERC approved costs for PJM Regional Transmission Enhancement Plan charges, PJM Expansion Cost Recovery, as well as any other FERC-approved PJM transmission charges billed to the Company by PJM that will not be reconciled through the Company's Price To Compare Default Service Rate Rider and/or Hourly Pricing Default Service Rider and are approved by the Commission for recovery under this rider. Forecasted NMB costs are allocated to each Customer Class based upon each Customer Class's contribution to the total Company Network Service Peak Load.

E = The over or under-collection of the NMB_C that results from billing of the NMB during the DSS Reconciliation Year, including applicable interest. An over-collection is denoted by a positive E and an under-collection by a negative E. Interest shall be computed monthly at the legal statutory interest rate stated in 41 P.S. § 202, from the month the over or under-collection occurs to the month that the over-collection is refunded to or the under-collection is recovered from Delivery Service Customers.

S = The Company's total DSS Sales per Customer Class to Delivery Service Customers projected for the DSS Computational Year.

RIDERS

Rider J (continued)

The NMB rates billed to Customers by Rate Schedule are shown below. The TSC_1 rates billed to Customers shall be adjusted by the following Rate Schedule Adjustment Factors shown below:

Rate Schedule	**Rate Schedule Adjustment Factors**	**TSC_1 Rate**	**NMB Rate**
Rate Schedule RT & GS Volunteer Fire Company and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate – TOD	0.9086	0.123	0.087
Rate Schedule RS & GS Volunteer Fire Company and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate – Non-TOD	1.0759	0.145	0.087
Rate Schedule GS – Small	1.0560	0.143	0.100
Rate Schedule GS – Medium	1.0560	0.143	0.100
Rate Schedule GS – Large	0.9939	$0.726	$0.483
Rate Schedule GP	0.9332	$0.681	$0.483
Rate Schedule TP	0.8911	$0.651	$0.483
Rate Schedule MS	0.9702	0.131	0.100
Rate Schedule OL	0.6712	0.091	0.100
Rate Schedule ST	0.6721	0.091	0.100
Rate Schedule LED	0.6721	0.091	0.100
Rate Schedule BRD	0.9550	0.129	0.100

The above rates are listed as a cent per kWh, with the exception of Rate Schedules GS – Large, GP and TP which are listed as a dollar per kW NSPL

RIDERS

Rider J (continued)

Retail Enhancements

$$RE = [(RE_c – E) / S]$$

Where:

RE = The charge to be applied to Delivery Service Customers served under this rider for the Retail Enhancement Costs incurred by the Company.

REc = The Retail Enhancement Costs incurred by the Company to cover programming expenses and implementation costs associated with competitive market enhancements approved by the Commission.

E = The over or under-collection of the RE_C that results from billing of the RE during the DSS Reconciliation Year, including applicable interest. An over-collection is denoted by a positive E and an under-collection by a negative E. Interest shall be computed monthly at the legal statutory interest rate stated in 41 P.S. § 202, from the month the over or under-collection occurs to the month that the over-collection is refunded to or the under-collection is recovered from Delivery Service Customers.

S = The Company's total DSS Sales per Customer Class to Delivery Service Customers projected for the DSS Computational Year.

The RE rates by Customer Class to be included in DSS rates are as follows:

Industrial Customer Class (Rate GS – Large, GP and Rate TP):

$0.000 per kW NSPL

Commercial Customer Class (Rate GS-Small):

0.004 cents per kWh

Residential Customer Class (Rate RS and Rate GS – Volunteer Fire Company, Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate):

0.006 cents per kWh

RIDERS

Rider J (continued)

Customer Education Charges

$$CEC = (CEC_C - E) / S$$

Where:

CEC = The charge to be applied to Delivery Service Customers served under this rider for Customer Education Charges incurred by the Company.

CEC_C = Customer Education costs for the specific Customer Class to cover customer education costs associated with competitive market enhancements approved by the Commission.

E = The over or under-collection of the CEC_C that results from the billing of the CEC during the DSS Reconciliation Year, including applicable interest. An over-collection is denoted by a positive E and an under-collection by a negative E. Interest shall be computed monthly at the legal statutory interest rate stated in 41 P.S. § 202 from the month the over or under-collection occurs to the month that the over-collection is refunded to or the under-collection is recovered from Delivery Service Customers.

S = The Company's total DSS Sales per Customer Class to Delivery Service Customers projected for the DSS Computational Year.

The CEC rates by Customer Class to be included in DSS rates are as follows:

Industrial Customer Class (Rate GS – Large, GP and Rate TP):

$0.000 per kW NSPL

Commercial Customer Class (Rate GS-Small):

0.044 cents per kWh

Residential Customer Class (Rate RS and Rate GS – Volunteer Fire Company, Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate):

0.006 cents per kWh

RIDERS

Rider J (continued)

Gross Receipts Tax

T = The Pennsylvania gross receipts tax rate in effect during the billing month expressed in decimal form as reflected in the Company's base rates.

All capitalized terms not otherwise defined in this Rider shall have the definitions specified in Section 2 of this Tariff. For purposes of this Rider, the following additional definitions shall apply:

1. DSS Sales – The kWh or kW NSPL delivered during a billing month to all Delivery Service Customers, as applicable to each Rate Schedule billed under the DSS Rider.

2. DSS Computational Year – The 12-month period from June 1 through the following May 31.

3. DSS Reconciliation Year – The 12-month period ending March 31 immediately preceding the DSS Computational Year.

4. DSS Initial Computational Period – the period from October 3, 2014 through May 31, 2015 that the DSS Rider is in effect. Thereafter, the DSS Computational Year will be in effect.

The Company shall recalculate its DSS Rates annually and, based on that recalculation, shall file with the Commission, by May 1st of each year, revised Rates to become effective on June 1st of the same year unless the Commission orders otherwise. The revised DSS rates shall remain in effect for a period of one year, unless revised on an interim basis subject to the approval of the Commission. Upon determining that its DSS rates, if left unchanged, would result in material over or under-collection of all costs incurred, or expected to be incurred, for DSS during the then current DSS Reconciliation Year, the Company may request that the Commission approve one or more interim revisions to its DSS rates to become effective thirty (30) days from the date of filing, unless the Commission orders otherwise.

At the conclusion of the period during which this DSS Rider is in effect, the Company shall be authorized to recover or refund at any time, any remaining differences between recoverable costs and revenues billed under this rider by charges or credits to be applied to customer's bills under such mechanism the Commission may approve, but uncollectibles, which are non-reconcilable under the terms of this rider, shall not be included in the final reconciliation.

Application of the DSS rates shall be subject to annual review and audit by the Commission.

RIDERS

RIDER K
TIME-OF-USE DEFAULT SERVICE RIDER

Availability

Time-Of-Use ("TOU") default service ("$TOU_{Default}$") is available under this Rider, upon the terms and conditions set forth herein, to the Residential Customer Class that: (1) have had smart meters installed pursuant to the Met-Ed Smart Meter Technology Procurement and Installation Plan following approval of that plan by the Commission; and (2) affirmatively elect to receive service under this Rider and comply with its enrollment procedures. Customers that apply for service under this Rider must agree, as a condition of service hereunder, to allow the Company to share their Customer information as defined in the Company's Electric Generation Supplier Coordination Tariff with the EGS(s) that provides $TOU_{Default}$, subject to the requirements, restrictions and limitations, if any, of the Commission's applicable regulations dealing with the release of Customer information.

Rates

Summer Period of service rendered June 1 – August 31:

On-Peak Rate shall be determined as follows:

$TOU_{Default\ On\text{-}Peak}$ = Residential Customer Class $PTC_{Default}$ Rate X 1.28

Off-Peak Rate shall be determined as follows:

$TOU_{Default\ Off\text{-}Peak}$ = Residential Customer Class $PTC_{Default}$ Rate X 0.82

Non-Summer Period:

$TOU_{Default}$ = Residential Customer Class $PTC_{Default}$ Rate

RIDERS

Rider K (continued)

TOU$_{Default}$

Qualifying Customers that are enrolled to receive service under this Rider will obtain TOU default service from a Commission-certified EGS contracted to provide TOU default service pursuant to the terms and conditions of this Rider.

Each enrolled Customer must execute, and will receive service pursuant to, a Commission-approved consumer contract and disclosure statement with an EGS selected to furnish TOU default service until such time as Customer selects another option from the EGS, selects another EGS, or requests a return to Default Service consistent with existing switching rules or until the Commission orders changes to the TOU Default Service Rider. The consumer contract and disclosure statement will set forth terms of service specified by the EGS that are in addition to, but may not conflict with, the rates, terms and conditions of service set forth in this Rider.

The rates for TOU default service set forth in this Rider will be calculated at the end of each Default Service Quarter (three months ending June 30th, September 30th, December 31st, and March 31st) to be effective for the three-month period beginning on the first day of the third month following the end of the Default Service Quarter (September 1st, December 1st, March 1st, and June 1st).

On-Peak and Off-Peak Hours

The rates for TOU default service are different for On-Peak Hours and Off-Peak Hours during the months of June, July and August, and billed on a service rendered basis. The TOU default service rate for all other months will not reflect an On-Peak or Off-Peak differential. On-Peak Hours are all hours beginning 8:00 AM (800 hours) Eastern Standard Time and ending 8:00 PM (2000 hours) Eastern Standard Time each day from Monday through Friday excluding Independence Day. Off-Peak Hours are all hours not identified as On-Peak Hours.

Enrollment

Enrollment will occur consistent with the switching rules provided in the Company's Electric Generation Supplier Coordination Tariff.

RIDERS

Rider K (continued)

Customer Switching

A Customer that has enrolled in the TOU default service program remains eligible to return to standard Default Service. A Customer that has enrolled in the TOU default service program may, at any time, elect to receive another product from any EGS, including non-TOU default service from the EGS providing TOU default service to the Customer pursuant to this Rider.

Commission's Failure to Approve an EGS Contract and Alternative Rates

In the event the Commission does not approve a standard contract for use between the Company and participating EGSs or no EGS elects to provide TOU default service, Customers enrolled, or electing to enroll,, in the TOU default service program will receive service under the terms and conditions of the Company's Price To Compare Default Service Rate Rider, and the $TOU_{Default}$ rates shall be the rates set forth in such Price to Compare Default Service Rate Rider (including, without limitation, "E" Factor of such rates). During the Summer Period, the $PTC_{Default}$ rate will be multiplied by 1.28 to establish the $TOU_{Default\ On\text{-}Peak}$ rate during On-Peak Hours and multiplied by 0.82 to establish the $TOU_{Default\ Off\text{-}Peak}$ rate during Off-Peak Hours.

EGS Withdrawal From Providing TOU Default Service

In the event an EGS providing service through the TOU Default Service Rider elects to withdrawal from providing such service, the Company may randomly reassign the Customers receiving TOU default service from such EGS to the remaining EGSs that are providing TOU default service on behalf of the Company.

Annual Review and Audit

The application of the $TOU_{Default}$ rates under this Rider shall be subject to annual review and audit by the Commission.

RIDERS

RIDER L
PARTIAL SERVICES RIDER

AVAILABILITY/APPLICABILITY:

This Rider applies to general service customers having on-site non-synchronous generation equipment or synchronous equipment that does not qualify for Net Metering Rider capable of supplying a portion of their power requirements for other than emergency purposes. Electricity sold under this Rider may not be resold; nor may it be used to operate the auxiliary loads of the generating facilities while those facilities are generating electricity for sale.

All of the following general monthly charges are applicable to Delivery Service Customers.

GENERAL MONTHLY CHARGES:

Seventy-Nine Dollars and Twenty-Eight Cents ($79.28)/per month, plus the charges listed below, depending upon the voltage at which the Customer is being served and the services (i.e., Backup Demand and/or Maintenance Demand) selected by the Customer:

Distribution Charge	**Backup Demand** (Dollars/KW)	**Maintenance Demand** (Dollars/KW)
Secondary Voltage	$2.72	$2.18
Primary Voltage	$2.51	$2.01
Transmission Voltage	$0.54	$0.43

RIDERS

Rider L (Continued)

PAYMENT TERMS:

As per Rule 11, Payment of Bills.

TERM OF CONTRACT:

Each Customer shall be required to enter into a Delivery Service contract with the Company for a minimum one (1) year term. If the Delivery Service contract is terminated by the Customer prior to its expiration, the Minimum Charge provisions of this Rate Schedule shall apply. If the Customer's capacity or service requirements increase, the Company, in its sole and exclusive judgment, may at any time require the Customer to enter into a new Delivery Service contract.

TERMS AND CONDITIONS:

A. Except where modified by this RIDER L, the Customer shall be subject to the terms and conditions of the Rate Schedule that would otherwise apply to the Customer.

B. Service under this RIDER L shall be supplied only at locations where, in the Company's sole and exclusive discretion, there exists lines and equipment of sufficient capacity to supply the service requested by the Customer.

C. The Customer's total combined capacity for the Backup and Maintenance Service shall not exceed the capacity of the generator(s) or other source of power to the Customer that is experiencing the outage.

D. The Customer's generators or other source of supply shall not be operated in parallel with the Company's lines except upon written consent of the Company or as defined under the contractual arrangements.

E. The periods of the year to be considered peak periods are from December 15 through March 15 and May 31 through September 15. Non-peak periods shall be the remaining periods of the year. Peak and non-peak periods may be changed from time to time by the Company after giving notice to the Customer.

F. For purposes of this RIDER L, the On-peak hours shall be defined as 9 a.m. - 9 p.m. weekdays with Off-peak hours encompassing all other hours.

RIDERS

Rider L (continued)

G. The Company may, at its option, require the Customer to install metering equipment sufficient to verify the performance of the Customer's generating equipment.

GENERAL PROVISIONS:

A. BACKUP SERVICE:

1. Following the written request of the Customer indicating the amount of Backup Service required, the Company shall supply such service each month at the charges listed under General Monthly Charges.

2. During any billing period in which the Customer's generating equipment or other source of power experiences a forced or unscheduled outage which requires the Company to provide backup energy, the Customer shall be required to pay the Company for (i) the backup capacity at the charges listed in this Rate QF, General Monthly Charges, (ii) all capacity in excess of the specified capacity as Supplemental Service, and (iii) all energy purchased at the charges and applicable riders set forth in the Rate Schedule that would otherwise apply to said Customer.

3. During any billing period in which the Company is not required to provide energy to "backup" the Customer's generating equipment or other source of power, the Customer shall pay to the Company the charges listed under General Monthly Charges for backup capacity.

RIDERS

RIDER L (continued)

4. Backup Service at the charges listed in this Rate QF, General Monthly Charges is limited to fifteen percent (15%) of the On-peak hours and fifteen percent (15%) of the Off-peak hours during any and all consecutive twelve-month billing periods. Backup Service beyond fifteen percent (15%) of the time during a particular consecutive twelve-month period shall be billed to the Customer by the Company as Supplement Service at the Rate Schedule that would otherwise apply to said Customer.

5. The Customer shall permit the Company to install metering on the customers generation at the customers expense (phone line) or the Customer is required to notify the Company of the failure of its generating equipment in order to invoke RIDER L Paragraph A2 of the Backup Service provision. The Company shall not be required to rebill the Customer if the Company is not notified of the equipment failure prior to the Company's scheduled billing date of the Customer's account.

6. Back-up Service Billing Demand shall be the Contract Demand for Back-up Service.

7. The Back-up Service Measured Demand shall equal the lesser of a) the difference between the generating capability of the Customer's generator less the actual amount generated in a 30 minute period as measured by Company's metering located on the Customer Generator, or as provided with documentation acceptable to the Company by the Customer, or b) the Back-up Service Billing Demand.

B. MAINTENANCE SERVICE:

1. At the option of the Company, Customers may schedule their maintenance outages at any and all hours, during the periods from March 15 to May 31, September 15 to December 15, July 4 and Labor Day. Customers may also schedule their maintenance outages during Off-peak hours of the remainder of the year. For purposes of this RIDER L, On-peak shall be defined as 9 a.m. - 9 p.m. weekdays, with all Off-peak hours being all other hours.

2. Customers who schedule their maintenance outages as set forth in RIDER L Paragraph B1 and who request maintenance service in accordance with RIDER L Paragraph B7, shall be billed by the Company at the charges listed under General Monthly Charges for the additional demands created during the scheduled outage up to the amount of requested maintenance power. In addition, the Customer shall be billed by, and pay to, the Company normal monthly charges including, but not limited to, the Monthly Minimum Charges, Demand Charges, Backup and Energy Charges at the Rate Schedule(s) that would otherwise apply to said Customer.

RIDERS

Rider L (continued)

3. The additional demands, subject to maintenance charges, created during the scheduled outage shall not exceed the specified Maintenance Service capacity. Maintenance Service at the charges listed under General Monthly Charges shall be limited to twenty-five percent (25%) of the time (i.e., hours) during any and all consecutive twelve (12) month periods. Maintenance Service beyond twenty-five percent (25%) of the time during a particular consecutive twelve (12) month period shall be billed by the Company at the Rate Schedule that would otherwise apply to said Customer.

4. When the Customer's scheduled maintenance outage of the generating facility cannot be scheduled in accordance with Rate QF Paragraph B1, the demand established shall be subject to the charges and conditions set forth in the applicable Rate Schedule that would otherwise apply to said Customer.

5. The Company may, at its option, allow a Customer to extend the maintenance outages into On-peak periods provided that the length of extension into these periods does not exceed five (5) days. The demands established during these periods shall be billed by the Company at the charges specified in General Monthly Charges.

6. The Customer shall provide thirty (30) days written advance notice to the Company of a scheduled maintenance outage and specify the amount of maintenance power required. The Company shall make the Maintenance Service available within (30) days before or after the Customer's requested maintenance outage.

C Supplement Service

1. All electric energy consumed in excess of Backup Service Measured Demand and or Maintenance Service Measured Demand shall be considered Supplemental Service. Supplemental Service shall be provided and billed under that rates, terms and conditions of the otherwise determined rate schedule

RIDERS

Rider L (continued)

2. Customers who wish to schedule their maintenance outages during periods other than those described in RIDER L Paragraph B1, may at the sole and exclusive discretion of the Company, do so on an interruptible basis. The Company may request that a Customer interrupt their scheduled maintenance outage during periods of system constraint, system emergency, or during periods of high cost energy purchases. When the Customer requests a scheduled interruptible maintenance outage, a non-interruptible Maintenance Service requirement, not to exceed one percent (1%) of the requested maintenance capacity, shall be specified. When the Company requests a Maintenance Service interruption, the Customer shall reduce its Maintenance Service requirements to the pre-determined non-interruptible base level within thirty (30) minutes of notification by the Company. Failure to do so shall result in the Company issuing a bill to the Customer for the demand established during the requested interruption in excess of the non-interruptible base at the demand charges set forth in the Rate Schedule that would otherwise apply to said Customer. The Company shall notify the Customer when a particular Maintenance Service Interruption is terminated.

RIDERS:

Bills rendered by the Company under this Rate Schedule are subject to the charges stated in any applicable Rider.

RIDERS

RIDER M

COGENERATION & SMALL POWER PRODUCTION
QUALIFYING FACILITY SERVICE RIDER
(Applicable to All Service Classifications)

Electricity produced by a "Qualifying Facility" ("QF"), as defined in § 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), with generating capacity of 500 KW or less shall be purchased by the Company in accordance with the terms of this Rider. Facilities with more than 500 KW of generating capacity or facilities that do not meet Federal Energy Regulatory Commission ("FERC") certification requirements under § 210 of PURPA shall apply for specific contract terms. All energy or energy and capacity credits utilized in A. and B. of this Rider shall be determined in accordance with applicable Commission and FERC regulations.

A. ENERGY PURCHASES BY COMPANY:

1. The purchase price for all Net Electric Energy not under the Net Metering Rider, supplied to the Company from the QF will be at Avoided Cost.
2. Avoided Cost shall be defined as the Real Time Location Marginal Price ("LMP") and as utilized in Paragraph 2 hereof shall mean the Real Time LMP for each hour at the Met-Ed zone aggregate hourly integrated market marginal clearing price for all Net Electric Energy as specified on the PJM Interconnection, L.L.C. or successor's website, which is currently www.pjm.com multiplied by seventy-five percent (75%).

3. Within sixty (60) days of the meter reading date, the Company shall render payment and furnish a written statement indicating the amount of energy received by the Company and the calculation of payment at applicable rates unless the QF has not delivered at least 5,000 KWH to the Company. In this instance, a statement will be rendered annually or within sixty (60) days of the meter reading that indicates at least 5,000 KWH has been delivered to the Company since the last statement. Each statement shall reflect the Company's Twenty-Five Dollars ($25.00) administrative charge. The Customer has thirty-five (35) days from the date of the payment to dispute a payment calculation. If after thirty-five (35) days from the date of the payment, the Customer has not contacted the Company, the payment and calculation shall be considered correct and accepted by the Customer

4 QFs with less than fifty (50) KW of generating capacity may select Net Energy Billing in accordance with the Company Policy set forth in B - Net Energy Billing Policy.

RIDERS

Rider M (continued)

B. NET ENERGY BILLING POLICY:

1. Where the potential for energy delivery to the Company is very small, the Company shall encourage the QF to interconnect with the Company's system and not sell surplus energy to the Company. Under these circumstances, the QF will avoid the cost of installing a second meter base since the Company will replace the normal KWH meter with a KWH meter with detent.

2. Where the QF elects to sell surplus energy to the Company, installation of a second meter base by the QF shall be required. The Company shall install two (2) KWH meters with detent. One (1) meter will record energy delivered from the Company to the Customer and supply the monthly billing determinants. The second meter will record energy delivered from the QF to the Company for the determination of the payment to the QF at a rate based upon the Company's average projected energy costs for the year ending December 31 of each filing year, as determined to the nearest 0.1¢ per KWH. Payment to the QF for energy delivered to the Company will be made annually, and a Twenty-Five Dollar ($25.00) administrative charge, by the Company shall be reflected therein.

C. INTERCONNECTION COSTS:

1. QF shall pay any incremental, i.e., additional, interconnection costs above the costs to service the Customer's electrical load which the Company incurs in order to purchase power from the QF. These incremental interconnection costs shall not include site specific costs such as, but not limited to, line extensions, facilities changes, special facilities, and right-of-way costs.

2. Payments for the incremental interconnection costs may, at the option of the QF, be made either as (i) a lump sum payment, or (ii) time payments spread over a mutually agreeable period of five (5) years or less. When the QF chooses to spread the payment over a mutually agreeable time period, the payments to the Company shall include an interest payment equal to the Company's allowed rate of return on common equity as last approved by the Commission as of the date the payment agreement is consummated.

3. After the QF installs the necessary interconnection equipment, the Company may require an inspection prior to making the interconnection. The Company shall have this inspection conducted within 20 days of notice by the QF that the installation has been completed and shall provide the QF with the results of this inspection within five (5) working days.

RIDERS

Rider M (Continued)

D. SAFETY AND RELIABILITY

1. Interconnection with the Company's system requires the installation of projective equipment which, in the Company's judgment, provides safety for personnel, affords adequate protection against damage to the Company's system or to its Customer's property, and prevents interference with the Company's supply of service to others. After installation and at any time this rate is in effect, the Company shall have the right to inspect the facilities and their operation, and to inspect and test all protective equipment.

2. Parallel operation must cease immediately and automatically during system outages and other emergency or abnormal conditions specified by the Company. The QF must cease parallel operation upon notification by the Company if such operation is determined to be unsafe, interferes with the supply of service to others, or interferes with system maintenance or operation. The Company is not liable for and accepts no responsibility whatsoever for any loss, cost, expense, damage or injury to any person or property resulting from the use or presence of electric current or potential which originates from a QF's generation facilities, or is caused by failure of the QF to operate in compliance with Company requirements.

3. The QF generation equipment must be equipped with a Company-controlled manually operable disconnecting device capable of being locked in the open position. This device will allow isolation of the QF's generator from the Company system and may be located at the interconnection point or at the QF's generator Interlocks must be provided to preclude paralleling the generator through any point other than the designated interconnection point.

4. Automatic reclosing shall not be installed on the interconnection disconnecting device.

5. Customer equipment must be equipped with a Company-approved overcurrent protective device and necessary relaying to interrupt generator fault current due to fault on the Company system.

6. The Customer may be required to install current limiting reactors to limit the magnitude of Customer-owned generator fault current.

RIDERS

Rider M (Continued)

E. PURCHASE AGREEMENT: No contract is required for QFs 500 kW or less who elect to receive the actual avoided cost at the time of the sale to the Company. In addition, those QFs of 50 kW or less that elect to have net energy billing do not require a written agreement. Those QFs greater than 500 kW wishing to use projections or levelized projections to sell power to the Company shall be required to sign a letter of agreement or other contract stating the terms of the transaction. No purchase will be made by the Company without such contract.

RIDERS

RIDER N
SOLAR PHOTOVOLTAIC REQUIREMENTS CHARGE RIDER

A Solar Photovoltaic Requirements Charge ("SPVRC"), determined to the nearest one-thousandth of a cent per kWh, shall be applied to each kWh delivered during a billing month to all Delivery Service Customers not qualifying for Solar Photovoltaic ("SPV") self-generation exclusion. The SPVRC shall be non-bypassable.

For service rendered June 1, 2014 through May 31, 2015, the SPVRC shall be equal to 0.014 cents per kWh for all kWh.

The SPVRC shall be calculated annually in accordance with the formula set forth below:

$$SPVRC = [(SPVRC_C - E) / S] X [1 / (1 - T)]$$

$$SPVRC_C = SPVRC_{Exp1} + SPVRC_{Exp2} + SPVRC_{Exp3} + SPVRC_{Exp4}$$

Where:

SPVRC = The charge in cents per kWh to be applied to each kWh delivered to Delivery Service Customers served under this tariff.

$SPVRC_C$ = Solar Photovoltaic Requirements Charge Costs calculated in accordance with the formula shown above.

E = The over or under-collection of SPVRC costs that results from billing the SPVRC during the SPVRC Reconciliation Year (an over-collection is denoted by a positive E and an under-collection by a negative E), including applicable interest. The E rate shall be applied to each kWh delivered to Delivery Service Customers. Interest shall be computed monthly at the legal rate determined pursuant to 41 P.S. § 202, from the month in which the over or under-collection occurs to the month in which the over-collection is refunded to or the under-collection is recovered from all Delivery Service Customers.

$SPVRC_{Exp1}$ = A projection of the costs incurred to acquire the Solar Photovoltaic Alternative Energy Credits ("SPAECs") to be retired during the SPVRC Computational Year obtained from winning bidders selected in the competitive procurement process to fulfill the Company's SPV obligations imposed by the AEPS Act and related laws and regulations, as the same may be amended from time to time ("AEPS Laws And Regulations").

RIDERS

Rider N (continued)

$SPVRC_{Exp2}$ = Administrative costs projected for the SPVRC Computational Year associated with the competitive procurement process implemented to fulfill the Company's SPV obligations imposed by the AEPS Laws And Regulations. These administrative costs include, but are not limited to, consultant costs and other direct and indirect costs associated with the Company's administration of the competitive procurement process and compliance with the SPV obligations imposed by the AEPS Laws And Regulations.

$SPVRC_{Exp3}$ = Incremental start-up costs incurred by the Company through May 31, 2013 in connection with the Company's compliance with the SPV obligations imposed by the AEPS Laws And Regulations, which shall be amortized over the twenty-four (24) month period ending May 31, 2015. These administrative costs include, but are not limited to, consultant costs and other direct and indirect costs associated with the Company's administration of the competitive procurement process and compliance with the SPV obligations imposed by the AEPS Laws And Regulations. Interest will be calculated monthly on the average of the beginning of the month and the end-of-month balances of these costs and included in the determination of the monthly amortized amount. The interest shall be computed monthly at the legal rate determined pursuant to 41 P.S. § 202.

$SPVRC_{Exp4}$ = The net of: 1) proceeds resulting from the sale into the market of excess, unused SPAECs procured by the Company in the competitive procurement process; 2) the cost of any additional or supplemental SPAECs purchased by the Company in the market outside of the competitive bid process, as needed to meet its SPV obligations under the AEPS Laws And Regulations; and 3) the carrying cost of banked SPAECs, computed and compounded monthly at the legal rate determined pursuant to 41 P.S. § 202 based upon the cost to acquire the banked SPAECs.

S = The Company's projected kWh sales to Delivery Service Customers for the SPVRC Computational Year less Excluded Sales.

RIDERS

Rider N (continued)

Excluded Sales = Projected net Delivery Service kWh sales for the SPVRC Computational Year to qualifying SPV self generating Customers, which shall be excluded from the SPVRC for the SPVRC Computational Year if the SPV self generating Customer satisfies the criteria set forth in "Qualifications for exclusion from SPVRC for Self Generation" as set forth below.

T = The Pennsylvania gross receipts tax rate in effect during the billing month expressed in the same decimal form used to express the Pennsylvania gross receipts tax rate that is employed in the Company's base rates.

All capitalized terms not otherwise defined in this Rider shall have the definitions specified in the Definitions of Terms section of this tariff. For purposes of this rider, the following additional definitions shall apply:

1. SPVRC Computational Year – The 12-month period from June 1 through the following May 31.

2. SPVRC Reconciliation Year – The 12-month period ending March 31 immediately preceding the SPVRC Computational Year.

The SPVRC shall be filed with the Commission by May 1st of each year. Changes to the SPVRC shall become effective on June 1 of each year unless otherwise ordered by the Commission, and shall remain in effect for a period of one (1) year, unless revised on an interim basis subject to the approval of the Commission. Upon determining that the SPVRC, if left unchanged, would result in material over or under-collection of all costs recoverable under the SPVRC Rider incurred or expected to be incurred during the then current SPVRC Computational Year, the Company may request that the Commission approve one or more interim revisions to the SPVRC to become effective thirty (30) days from the date of filing, unless otherwise ordered by the Commission.

RIDERS

Rider N (continued)

Qualifications for exclusion from SPVRC for providing SPAECs to the Company from a Customer owned SPV generator:

1. The exclusion is available to Customers served on Rate Schedules GS Large, GP, and TP.

2. Customer must submit an application to the Company in advance of the SPVRC Computational Year requesting a waiver of the SPVRC. As part of the initial application, the Customer must have an executed interconnection agreement with the Company pursuant to applicable interconnection regulations, must have installed qualifying SPV panels in an amount adequate to cover the SPAEC requirements for the Customer's expected net Delivery Service kWh, and must have installed qualifying metering on site to record the cumulative electricity production from its qualifying SPV panels in order to verify the SPAEC value determined pursuant to Act 213, Section 3 (A)(3)(e)(3). Upon the Company's approval of the Customer's application, this Rider shall not be applicable as long as the Customer continues to meet the qualifications for exclusion.

3. The Company will make an estimate of the Customer's SPAECs to be transferred to the Company based on the Company's determination of the Customer's most recent 12 months of net Delivery Service kWh. The amount of SPAECs will be rounded up to the nearest whole number. This value will be communicated to the Customer before the SPVRC Computational Year.

4. After the close of the SPVRC Computational Year, the Company will bill the Customer for the SPAECs necessary to extinguish the Customer's obligation. No later than 45 days after the end of the SPVRC Computational Year, the Customer must transfer the specified self generated SPAECs into the Company's GATS account to demonstrate compliance for the recently completed SPVRC Computational Year.

5. Upon receipt of all required SPAECs, the Company will continue to exclude the qualifying Customer from being billed the SPRVC.

RIDERS

Rider N (continued)

Penalty for non-compliance from Customers who qualify for the exclusion

If the Customer fails to meet the obligation spelled out in Paragraph 4, then the Customer shall pay to the Company, the market cost incurred by the Company to replace the SPAECs not delivered by the Customer.

The Company shall file an annual report of collections under this Rider within sixty (60) days following the conclusion of each SPVRC Reconciliation Year.

At the conclusion of the period during which this Rider is in effect, the Company shall be authorized to recover or refund any remaining amounts not reconciled at that time under such mechanism as approved by the Commission.

Application of this non-bypassable SPVRC shall be subject to annual review and audit by the Commission.

RIDERS

RIDER O
GRANDFATHERED ADVANCED METERS, METER-RELATED DEVICES OR NETWORKS RIDER

PURPOSE:

Listed in the table below are the Company's grandfathered advanced meters, meter-related devices or networks as contained in the Pennsylvania Public Utility Commission's Advanced Meter Catalog.

(GRANDFATHERED) ADVANCED METER CATALOG																	
ITEM NO.	NAME	MANUFACTURER	MODEL NUMBE	ADVANCED CAPABILITIES											CUSTOMER CLASS		
				LOAD PROFILE	REMOTE COMMUNICATION	PULSE OUTPUT	PASSWORD PROTECTION	BI-DIRECTIONAL / L = limited	MULTIPLE CALLOUT	OUTAGE NOTIFICATION / L=limite	POWER QUALITY / L= limited	OTHER: Reactive Power	OTHER:	RESIDENTIAL	COMMERCIAL	INDUSTRIAL
1	KV	General Electric	KV	X	X	X	X	L	X	L	L			X		
2	KV	General Electric	KV	X	X	X	X	L	X	L	L	X			X	X
3	Quad4	Siemens	Quad4	X	X	X	X	X	X	L	L	X			X	X
4																
5																
6																
7																
8																
9																
10																
11																
12																
13																
14																
15																
16																
17																
18																
19																
20																
	1. Additional charges for optional advance services may be charged to customers as appropriate.															
	2. Contact number for Meter Service questions- MDM Coordinator															
		FirrstEnergy Corporation	Phone:	330-384-5145												
		76 S. Main Street	Fax:	330-384-3869												
		Akron, OH 44308	Email:	vassn@firstenergycorp.com												

RIDERS

RIDER P
NON-UTILITY GENERATION CHARGE RIDER

A Non-Utility Generation ("NUG") Charge ("NUG-C") determined to the nearest one-thousandth of 1 mill per kWh, shall be applied to each kilowatt-hour ("kWh") delivered during a billing month to all Delivery Service Customers, and will be calculated at the end of each NUG Reconciliation Quarter (three months ending January 31st, April 30th, July 31st, and October 31st) to be effective for the NUG Billing Quarter (three-month period at the beginning on the first day of the second month following the end of the NUG Reconciliation Quarter). The NUG-C shall be non-bypassable for all customers.

The NUG-C rates shall be calculated in accordance with the formula set forth below and will be billed at the rates set forth in Table 1 of this rider.

$$NUG\text{-}C = [(NUG\text{-}C_{Delta\ Market} \times NUG\ Rate\ Group\ Allocation\ Factor) - E + NUG\ Balance_{Amort}] / S \times [1/(1-T)]$$

$$NUG\text{-}C_{Delta\ Market} = NUG\ Cost - NUG\ Market\ Value$$

$$E = [(NUG\text{-}C_{Delta\ Marketactual} + NUG\ Balance_{AmortActual}) + (- NUG\text{-}C_{Rev} - NUG\ Trust_{Withdactual})]$$

Where:

$NUG\text{-}C_{Delta\ Market}$	=	The difference between NUG Cost and NUG Market Value for the NUG Billing Quarter.
NUG Rate Group Allocation	=	The allocation of the $NUG\text{-}C_{Delta\ Market}$ to specific rate groups based on the NUG Rate Group Allocation Factors set forth in Table 1 of this rider.
NUG Cost	=	The estimated total cost to be incurred by the Company under contracts to purchase generation from non-utility generators during the NUG Billing Quarter.
NUG Market Value	=	The estimated market valuation for the NUG Billing Quarter of the Company's purchases from non-utility generators including the estimated Market Value of AEPS Credits to which the Company is entitled because of its contracts with non-utility generators.

RIDERS

Rider P (continued)

E	=	The cumulative over or under-collection of NUG Cost that results from billing the NUG-C through the end of the most recently completed NUG Reconciliation Quarter (an over-collection is denoted by a positive E and an under-collection by a negative E). This balance shall be determined by NUG Rate Group.
NUG Balance $_{Amort}$	=	A NUG Rate Group's NUG Balance at December 31, 2010 that shall be recovered through the NUG-C by amortizing such balance ratably from January 1, 2011 through May 31, 2013.
NUG-C$_{Delta\ MarketActual}$	=	The cumulative difference between actual NUG cost incurred and NUG market value received through the sale of energy, capacity and AEPS credits through the end of the NUG Reconciliation Quarter. This amount shall be maintained by NUG Rate Group.
NUG Balance $_{AmortActual}$	=	The cumulative actual NUG Balance for each NUG Rate Group at December 31, 2010 that shall be recovered through the NUG-C by amortizing such balance ratably from January 1, 2011 through May 31, 2013.
NUG Trust $_{WithdActual}$	=	The cumulative amount of actual withdrawals from the NUG Trust Fund, by NUG Rate Group, as previously determined by the Company in its sole discretion, through the end of the NUG Reconciliation Quarter.
NUG-C$_{Rev}$	=	The cumulative revenues billed to Retail Customers by NUG Rate Group under this Rider, excluding Pennsylvania gross receipts tax, through the end of the NUG Reconciliation Quarter

RIDERS

Rider P (continued)

S = The Company's total Delivery Service kWh sales by NUG Rate Group projected for the NUG Billing Quarter that the NUC-C rates will be in effect

T = The Pennsylvania gross receipts tax rate in effect during the billing month, expressed in the same decimal form used to express the Pennsylvania gross receipts tax rate that is employed in the Company's base rates.

Table 1

NUG Rate Group	**NUG Rate Group Allocation Factors**	**NUG Rate By Group In Cents per kWh**
NUG Rate Group 1 - Rate Schedule RS	.38194	(0.027)
NUG Rate Group 2 - Rate Schedule GS Volunteer Fire Company Non-Profit Ambulance Service, Rescue Squad and Senior Center Service , GS – Small, GS – Medium, GS Large, MS, OAL, STLT, LED, and BRD	.28698	(0.019)
NUG Rate Group 3 - Rate Schedule GP	.21474	(0.022)
NUG Rate Group 4 - Rate Schedule TP	.11634	(0.024)

All capitalized terms not otherwise defined in this Rider shall have the definitions specified in Section 2 of this Tariff.

The NUG-C rates shall be filed quarterly with the Commission 10 days prior to the effective date of the rate changes.

The Non-Utility Generation Charge Rider shall be subject to review and audit by the Commission

RIDERS

RIDER Q
RENEWABLE ENERGY DEVELOPMENT RIDER

PURPOSE:

This Rider allows Customers to install and operate renewable energy generation.

APPLICABILITY:

This Rider applies to Customers served under Rate Schedules RS, GS-Small and GS-Medium with single phase, secondary voltage service who install a device or devices not exceeding ten (10) KW which are, in the Company's sole judgment, a bona fide technology for use in generating electricity from qualifying renewable energy installations, and which will be operated in parallel with the Company's system. Qualifying renewable energy installations are limited to solar panels, wind, biomass, methane field and fuel cell generation. The Customer's equipment must conform to the Company's "Relay and Control Requirements for Parallel Operation of Nonutility Generation" and, as appropriate, IEEE Standard 929-1988 and UL Publication 1741 ("Power Conditioning Units for Use in Residential Photovoltaic Power Systems"). This Rider is not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

The Company will modify its distribution facilities, as necessary, to interconnect with the Customer at a single point of delivery. For all modification, additions or facilities necessary to interconnect with the Customer at a single point, the Company will charge the Customer the cost of such modifications, additions or facilities in excess of One Thousand Dollars ($1000). In addition, the Company will charge a processing fee for applications under this Rider of Three Hundred Dollars ($300) for non-photovoltaic installations and a fee of One Hundred Dollars ($100) for photovoltaic installations.

RIDERS

Rider Q (continued)

METERING AND BILLING PROVISIONS:

A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule RS, GS-Small or GS-Medium.

1. For Rate Schedules RS only, one non-detented, bi-directional meter may be installed. This meter will record the net energy sales to the Customer which will be billed under the applicable Rate Schedule. If the Customer's renewable energy installation generates more energy than the Customer uses in any billing month, the Company will not charge the Customer for any energy usage or pay the Customer for the excess energy delivered by the Customer to the Company.

2. Two (2) detented meters may be installed. One meter will measure the energy delivered by the Company to the Customer. The other meter will measure energy delivered to the Company by the Customer which is generated by the Customer's qualified renewable energy installation.

3. The Company may provide Qualified Meters on terms approved by the Commission.

Under Options 2. or 3. above, the Customer shall pay the Company for the amount of energy delivered by the Company to the Customer under the applicable Rate Schedule. The Company shall pay the Customer monthly for any energy delivered by the Customer to the Company at the Real Time Hourly LMP for the Met-Ed Zone, provided the Customer is authorized to sell energy to the Company under applicable law.

RIDERS

Rider Q (continued)

METERING CHARGE:

In addition to distribution facility and processing fees, the Customer shall compensate the Company for the estimated additional fully allocated cost of installing, maintaining and reading any additional or nonstandard metering required for installations under metering Option 3. of this Rider. There is no additional metering charge under metering Options 1. or 2. The sum of the meter readings from the two (2) meters in metering Options 2. and 3. will be used to calculate any applicable Transmission and Distribution Charges under the applicable Rate Schedule.

MINIMUM CHARGE:

The Minimum Charges under Rate Schedule RS, GS-Small, and GS-Medium apply for installations under this Rider.

RIDERS:

Bills rendered by the Company under this Rider shall be subject to charges stated in any other applicable Rider.

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2014-2428745

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. R-2014-2428743

PENNSYLVANIA POWER COMPANY
DOCKET NO. R-2014-2428744

WEST PENN POWER COMPANY
DOCKET NO. R-2014-2428742

Direct Testimony of Kimberlie L. Bortz

List of Topics Addressed

Electric Service Tariffs
Storm Damage Charge Riders
West Penn Universal Service Cost Rider

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DIRECT TESTIMONY
OF
KIMBERLIE L. BORTZ

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your name and business address.

A. My name is Kimberlie L. Bortz, and my business address is 2800 Pottsville Pike, Reading, PA 19612.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company as a Rates Advisor - Rates and Regulatory Affairs - Pennsylvania. The Pennsylvania Rate Department provides regulatory support for Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power") and West Penn Power Company ("West Penn") (collectively, the "Companies"). I am responsible to the Director - Rates and Regulatory Affairs - Pennsylvania for tariff interpretation, tariff filings and the design of rates.

Q. Please describe your educational background and professional experience.

A. I have a Bachelor of Science degree in Accounting from the University of Maryland, and I am a Certified Public Accountant in Pennsylvania. I have twenty-five years of professional experience, over twenty of which have been in the utility business. My educational background and work experience are more fully described in Appendix A to this statement.

Q. What is the purpose of your direct testimony?

A. As I explain below, Met-Ed, Penelec, Penn Power and West Penn are each filing new tariffs to replace their existing Pennsylvania Public Utility Commission ("Commission")-approved retail electric tariffs. In addition to setting forth the Companies' proposed distribution base rates, the new tariffs reflect changes designed to: (1) standardize the rules and regulations that will be applied by all of the Companies; (2) eliminate or modify various riders that are not applicable for "unbundled" electric service or are no longer in use for other reasons; and (3) introduce two new riders – specifically, Storm Damage Charge Riders ("Storm Riders"), which are included in all of the Companies' proposed tariffs, and a Universal Service Cost Rider ("USC Rider") applicable to West Penn's residential retail classes, which is included in West Penn's proposed tariff, to align with comparable riders already in effect for the other Companies. Accordingly, the purpose of my direct testimony is threefold. First, I explain the changes between the Companies' existing and proposed tariffs that are being made to establish standardized rules and regulations. Second, I identify the riders that have been eliminated or modified in the proposed tariffs and briefly summarize the reasons for doing so. Finally, I describe the proposed Storm Riders and West Penn's USC Rider and explain why adoption of these riders is appropriate.

Q. Are you sponsoring exhibits to accompany your testimony?

A. Yes. I am sponsoring portions of Exhibit 1 for each of the Companies and portions of West Penn Company Exhibit 2.[1] Each Company's Exhibit 1 is a copy of that Company's proposed electric service tariff that was filed with the Commission, together with applicable supporting data, proposing increases and changes in rates. The portions of each Company's Exhibit 1 that I prepared and am sponsoring consist of the following:

- **Rules and Regulations of the Companies' Exhibits 1 and West Penn Company Exhibit 2**.
- **Rider B of Companies' Exhibits 1 and West Penn Company Exhibit 2** – the proposed Storm Damage Charge Rider for each Company.
- **Rider C of West Penn Company Exhibit 1** - the USC Rider applicable to residential rate schedules being proposed by West Penn.

Additionally, I have prepared and am sponsoring Met-Ed, Penelec, Penn Power, West Penn and West Penn/PSU Exhibit KLB-1 and West Penn Exhibit KLB-2. Exhibit KLB-1 provides responses to filing requirements IV-B-1, IV-B-2 and IV-B-3. West Penn Exhibit KLB-2 consists of a schedule setting forth: (1) the normalized annual costs, shown separately for each component of West Penn's Universal Service Program, that West Penn proposes to recover during the first year that the USC Rider is in effect; and (2) the computation of the proposed Universal Service Charge (in cents per kWh) for that period.

[1] West Penn currently has two retail electric service tariffs. Tariff Electric-Pa. P.U.C. No. 39 contains the rates and terms of service for retail electric service furnished in the entirety of West Penn's service territory with the exception of Pennsylvania State University ("PSU"). Tariff Electric-Pa. P.U.C. No. 37 contains the rates and terms of service for retail electric service furnished to PSU, which is the only customer served on that tariff ("West Penn/PSU Tariff"). In the current rate filing, West Penn is proposing two tariffs – West Penn Company Exhibits 1 and 2 – that correspond to, and would replace, Tariff No. 39 and the West Penn/PSU Tariff, respectively.

II. THE PROPOSED ELECTRIC SERVICE TARIFFS

Q. Why are the Companies filing new tariffs rather than supplements to their existing tariffs?

A. As I previously explained, the Companies are proposing changes to standardize their Rules and Regulations and to eliminate or modify riders that are inconsistent with the provision of unbundled electric service or are no longer applicable for other reasons. It would have been administratively unwieldy – both for the Companies and for the Commission – and confusing for readers and reviewers if the Companies made those revisions by changing individual pages of their existing tariffs, as they would have to do in submitting tariff supplements. Additionally, by submitting new tariffs, the Companies have established a more uniform format and pagination for the Rules and Regulations contained in their respective proposed tariffs.

Q. Why are the Companies proposing to standardize their Rules and Regulations?

A. As a result of the FirstEnergy Corp. ("FirstEnergy")/GPU, Inc. ("GPU") merger in 2001, Met-Ed and Penelec joined Penn Power as subsidiaries of FirstEnergy. With the merger of FirstEnergy and Allegheny Energy, Inc. ("Allegheny") in 2011, West Penn also became a FirstEnergy subsidiary. As members of a single corporate family that each provide electric distribution and default electricity supply service in the Commonwealth subject to the Commission's regulatory jurisdiction, many of the Companies' business activities are operated consistently with a uniform set of processes. This standardization of various processes,

procedures and operating systems across all of the Companies, as appropriate and consistent with furnishing safe and reliable electric service, has helped the Companies capture the economies of scale and realize the synergies expected from the FirstEnergy/GPU and FirstEnergy/Allegheny mergers. As Mr. Fullem explains in Met-Ed/Penelec/Penn Power/West Penn Statement No. 1, those merger-related benefits, as well as efficient management and concerted efforts to control operating and maintenance costs, allowed the Companies to extend the period between their prior base rate cases and the instant rate filings. Consequently, the Companies have determined that their generally applicable tariffs (that is, excluding the West Penn/PSU Tariff) should, as appropriate, reflect their common business processes. Establishing uniform Rules and Regulations will extend to the Companies' tariffs and tariff administration a level of standardization that will help create a uniform customer experience across the Companies' service territories; streamline the Companies' practices to the benefit of the Commission and non-customer parties such as customer advocates and electric generation suppliers ("EGSs"); and help to control the Companies' administration costs.

Q. Are the Companies also standardizing the terms of their respective rate schedules?

A. Yes. In general, as Mr. Siedt explains in Met-Ed/Penelec/Penn Power/West Penn Statement No. 4, the Companies' proposed rates would move toward standard rate designs, but the Companies are not proposing to standardize all of their rate designs in these proceedings.

A. Rules And Regulations

Q. How are the general provisions, including the Rules and Regulations, organized in each of the Companies' currently effective tariffs?

A. Each of the current generally applicable tariffs contains a table of contents followed by a description of the territory each Company serves. For Met-Ed and Penelec, the territory description is followed immediately by their "General Rules and Regulations." Rule 1 for each of those Companies explains that their tariff is filed with the Commission, is available for public inspection and may be accessed on the Company's website. Rule 1 also explains generally the purpose of the tariff and the forms of service to which it applies. Met-Ed's and Penelec's Rule 2 sets forth definitions of terms used in their tariffs. The remaining rules go on to explain the various terms of service, including those related to billing, installation of new service, application for service, metering, and other such provisions. The Penn Power and West Penn tariffs do not contain provisions comparable to Met-Ed's and Penelec's Rule 1, and they set forth the definition of terms as a general introductory section that is not part of their Rules and Regulations. Like the Met-Ed and Penelec tariffs, the Penn Power and West Penn tariffs move on from the definition of terms to discuss the various substantive terms and conditions of service in successive rules.

Q. Are the Companies proposing changes to the general provisions and to existing Met-Ed/Penelec Rules 1 and 2?

A. Yes, they are. Each of the proposed generally applicable tariffs will contain the equivalent of Rule 1 of the current Met-Ed and Penelec tariffs. However, it will

appear as a general provision preceding the Rules and Regulations. Additionally, in each of the proposed generally applicable tariffs the "Definition of Terms" appears as the second general provision immediately preceding the Rules and Regulations.

Q. Have the proposed "Definition of Terms" been modified from the comparable sections in the Companies' existing tariffs?

A. Yes, they have been modified in two respects. First, they have been expanded or reduced to either include terms that were not defined in all of the Companies' current tariffs or to eliminate those terms that are no longer used or relevant. Second, some terms that, for certain Companies, are defined elsewhere in their tariffs have been moved to the Definition of Terms. The goal was to identify commonly used terms that appear throughout each tariff and provide uniform definitions in the Definition of Terms.

Q. Please identify the major differences among the Rules and Regulations in each of the Company's currently effective generally applicable tariffs.

A. The current tariffs of Met-Ed and Penelec are similar to each other. Each has twenty-four rules comprising its General Rules and Regulations, which include Rules 1 and 2 that, as I previously explained, will become general provisions preceding the Rules and Regulations in the proposed tariffs. Penn Power's tariff and the tariff for service throughout West Penn's service territory, on the other hand, have historically included more rules in their Rules and Regulations (forty-five for Penn Power and forty-three for West Penn). However, many of the

additional rules in the Penn Power and West Penn tariffs simply repeat, paraphrase or incorporate by reference Commission regulations already set forth in Title 52 of the Pennsylvania Code. Repeating, paraphrasing or incorporating by reference the Commission's regulations makes the Rules and Regulations needlessly long and redundant. It also creates risks that a rule paraphrasing or summarizing a Commission regulation will not accurately capture that regulation's meaning or that subsequent revisions to the regulation will make the Rules and Regulations inconsistent with current regulatory requirements.

Q. Do the Rules and Regulations contained in the West Penn/PSU Tariff differ from those of West Penn's generally applicable tariff?

A. Yes. Because of the specific nature of the West Penn/PSU Tariff, the Rules and Regulations in that tariff are more limited in scope. The existing West Penn/PSU Tariff consists of a Definitions section followed by a General Rules and Regulations section containing ten rules.

Q. How do the proposed tariffs for Penn Power and West Penn address the concerns you noted above?

A. Rules that simply repeat, paraphrase or incorporate Commission regulations have been eliminated, which is the principal reason that the number of rules in the proposed tariffs are fewer than those in the current Penn Power and West Penn tariffs.

Q. What general approach was employed in developing the Rules and Regulations in the proposed tariffs?

A. The Rules and Regulations in the Met-Ed and Penelec tariffs were used as the model for the standardized tariffs. The Companies determined that, with few modifications (such as moving Rules 1 and 2 to initial general provisions), the Met-Ed and Penelec Rules and Regulations provide a clear, concise explanation of the terms of service that are important to customers. Additionally, the Met-Ed and Penelec tariffs were the latest that the Commission and various parties had an opportunity to review, which occurred in the 2006 base rate cases for those Companies. Also, given that the format of the Met-Ed and Penelec tariffs already mirrored one another, the Companies believed these tariffs to be a more efficient starting point. However, due to the limited and customer-specific nature of the West Penn/PSU Tariff, fewer modifications, based upon the existing Met-Ed and Penelec tariffs, were made to that proposed tariff.

Q. Can you summarize, by rule, the subjects covered in the Rules and Regulations in each of the proposed generally applicable tariffs?

A. Yes. That summary is provided below[2]:

- **Rule 1 – Applications/Contracts** describes the process for initiating service and requesting changes to existing service.

[2] In the summary of rules, I have capitalized terms that are defined in the Definition of Terms of the proposed tariffs (e.g., "Applicant" and "Customer"), but did not continue to do so in the balance of my direct testimony.

- **Rule 2 – Deposits** sets forth the criteria that will be used to determine when a deposit will be required as a condition of service, specifies how the amount of a Customer Deposit is determined and the terms on which deposits are held and returned.

- **Rule 3 – Right-of-Way** sets forth the requirements for an Applicant for service or Customer to provide a right-of-way, easement or permits to access the Customer's property in order for service to be furnished.

- **Rule 4 – Extension of Company Facilities: System Upgrades** sets forth the terms and conditions for the extension of Company facilities to serve an Applicant or Customer; the institution of temporary service; and the relocation of, or modification to, Company facilities at the request of a customer or to accommodate a service request.

- **Rule 5 – Taxes on Applicant/Customer Advances** explains how income taxes are to be calculated for the purpose of "grossing up" Customer Advances for applicable state and federal income taxes.

- **Rule 6 – Proof of Inspection** sets forth the requirement that a Customer or Applicant provide to the Company proof of inspection under the Uniform Construction Code before the Company will initiate or upgrade service to a residential building.

- **Rule 7 – Wiring, Apparatus and Inspection** sets forth: (a) the installation, maintenance, repair and replacement obligations of the

Company and the Customer for facilities that each is required to install to initiate and maintain service; (b) inspection requirements under the National Electric Code and other applicable codes that must be satisfied for the Company to connect its facilities to the Customer's installation; and (c) the Customer's obligation to install corrective equipment, and furnish associated service information, to deal with high instantaneous demands and power factors below 85% (lagging).

- **Rule 8 – Metering** sets forth the obligations and requirements imposed on the Company and the Customer, respectively, for the installation and maintenance of metering equipment and payment of the associated costs.

- **Rule 9 – Access to Customer Premises** sets forth the Company's right to have access to equipment located on a Customer's premises.

- **Rule 10 – Meter Reading and Rendering of Bills** sets forth the terms for reading Customer meters and rendering bills; providing billing data at the Customer's request; issuing estimated bills; summary billing; special billing; the residential Equal Payment Plan; combined billing for Residential and Outdoor Lighting service; consolidated billing for a Customer that has contracted with an EGS; minimum charges; transformer loss adjustment; power factor and kilovar billing; billing for vandalism, theft or deception; and billing errors.

- **Rule 11 – Payment of Bills** sets forth provisions relating to the determination of applicable due dates, late payment charges, allocation of

payments, delinquent accounts (including collection of outstanding residential account balances), and winter termination rules.

- **Rule 12 – Administrative Charges** sets forth the three principal administrative charges the Company may impose, namely, initiation/reconnection service charges, dishonored check/electronic transfer charges, and disconnection/reconnection charges.

- **Rule 13 – Determination of Demand** addresses the measurement of a Customer's active and, if applicable, reactive demand.

- **Rule 14 – Individualized Contracts** provides the terms and conditions for entering into individualized contracts with non-Residential Applicants or Customers.

- **Rule 15 – Company Facilities, Services and Products** sets forth the terms and conditions, including Customer payment obligations, for the Company to provide, at an Applicant's or Customer's request, special, substitute, or emergency repairs or additional or non-standard facilities, services or products.

- **Rule 16 – Auxiliary Power Sources and Readiness to Serve** sets forth the terms and conditions of service to a Customer whose electric requirements are provided in whole or in part from sources other than Company-owned facilities and where the Company's supply can be substituted for that of the Customer.

- **Rule 17 – Interconnection, Safety & Reliability Requirements** sets forth the requirements and standards that apply to all types of Generating Facilities, including Customer owned Generating Facilities, that must be satisfied before such Generating Facilities may be interconnected with the Company's system.

- **Rule 18 – Load Control** defines the conditions that can give rise to a load emergency situation and sets forth the actions the Company may take to bring demands within the then-available capacity or to otherwise control load.

- **Rule 19 – Energy Conservation** deals with restrictions on the fuel supplies available to Company energy vendors that may adversely affect the supply of electric energy to Customers, such that an emergency energy conservation situation would be created. It also authorizes the Company to take reasonable measures that it believes are necessary and proper during such emergency situations to conserve available fuel supplies, including reducing, interrupting or suspending Customer service.

- **Rule 20 – Discontinuance** sets forth the terms and conditions for discontinuing service to a Customer for, among other reasons: non-payment of delinquent bills; violating provisions of the Company's tariff; to avoid endangering the safety of persons or property, including the Company's system; to comply with government rules, regulations,

statutes, orders and directives; and to make necessary repairs, changes or improvements to the Company's system.

- **Rule 21 – Service Continuity: Limitation on Liability for Service Interruptions and Variations** sets forth: (a) the Customer's responsibility for the safety and adequacy of the wiring and equipment it installs; (b) the terms of indemnification of the Company by the Customer for liability resulting from a Customer's use of electric service furnished by the Company, for defects on a Customer's premises, and for a Customer's failure to comply with the National Electrical Code; (c) the qualification that the Company does not guarantee a continuous, uninterrupted or regular supply of electric service, that it may interrupt service, and that it will not be liable for force majeure-like events; and (d) limitations of the Company's liability.

- **Rule 22 Transfer of Electric Generation Supplier** sets forth the terms and conditions for processing requests by a Customer to initiate, terminate or change its EGS.

Q. Are there any significant substantive differences between the Rules and Regulations in the proposed tariffs and the General Rules and Regulations in the current Met-Ed and Penelec tariffs on which the proposed generally applicable tariffs are modeled?

A. Yes. In addition to moving the existing Rules 1 and 2 to introductory general provisions, the Companies have edited several of the Rules and are proposing the

following changes: (1) removing existing Rule 18 – Backup and Maintenance Service from the Rules and Regulations and replacing it with the proposed Partial Service Rider, as further described by Mr. Siedt in Met-Ed/Penelec/Penn Power/West Penn Statement No. 4; (2) adopting proposed Rule 16 – Auxiliary Power Sources and Readiness to Serve from the currently effective West Penn General Rules and Regulations, which sets forth the terms and conditions of service for a customer whose electric requirements are provided in whole or in part from sources other than Company-owned facilities and where the Company's supply can be substituted for that of the Customer; (3) adding to the description of the Purchase of EGS Receivables ("POR") Program language that expressly incorporates costs incurred pursuant to the POR Program in calculating customer deposits (Rule 2), late payment charges and delinquent accounts (Rule 11); and (4) removing language pertaining to Advanced Payment Billing from Rule 10 because that provision terminated by its terms as of January 11, 2007. All other rules are similar in all substantive respects to the General Rules and Regulations in the existing Met-Ed and Penelec tariffs.

Q. Are there any substantive differences between the Rules and Regulations in the proposed West Penn/PSU Tariff and the General Rules and Regulations in the current West Penn/PSU Tariff?

A. Yes. West Penn has eliminated or changed certain rules in the proposed West Penn/PSU Tariff, as follows:

- **Rule 1** – Continuity of Service was edited to be consistent with comparable provisions of the Companies' generally applicable tariffs.

- **Rule 2** – Metering was modified to remove the section that addresses EGS-provided advanced metering because, as I will explain later in connection with the Companies' generally applicable tariffs, this provision is inconsistent with the Commission-approved Smart Meter Deployment Plan that requires the Companies to install smart meters for all customers.

- **Rule 8** – Interim Code of Conduct and Rule 9 – GENCO Code of Conduct were removed because both have been superseded by subsequently adopted regulations and, as explained previously, rules that repeat, paraphrase or summarize existing regulations are redundant and create risks that they will misstate that regulation's meaning or that subsequent revisions to the regulation will make the Rules and Regulations in the Companies' tariffs inconsistent with current regulatory requirements.

- **Rule 10** – State Tax was eliminated. The Company's liability to pay state taxes not paid by an EGS is more appropriately addressed in its supplier tariff.

B. Changes To Existing Tariff Riders

Q. Please summarize the riders in the Companies' current tariffs that will not be included in their proposed tariffs.

A. The proposed tariffs will eliminate or relocate five existing riders in the current tariffs of Met-Ed and Penelec, five existing riders in the current Penn Power tariff, eleven existing riders in the current generally applicable tariff of West Penn, and three existing riders in the current West Penn/PSU Tariff.

Q. Please identify the riders being eliminated from or relocated within the existing Met-Ed and Penelec tariffs.

A. The five existing riders being eliminated from or relocated within the Met-Ed and Penelec tariffs and the reasons for doing so are as follows:

- **Rider B – Cogeneration and Small Power Production Qualifying Facility Service Rider:** Rider B deals with the terms on which the Companies purchase electricity produced by a Qualifying Facility ("QF"), as defined in § 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), with generating capacity of 500 KW or less. The matters covered by Rider B will be addressed in new Rider L – Partial Service and new Rider M – Cogeneration and Small Power Production Qualifying Facility Service.

- **Rider F – Metering and Billing Credit Rider:** Rider F provides customers monthly Distribution Charge credits if a Commission-licensed EGS, rather than the Company, were to provide customer metering, meter

reading or billing and collection service. Rider F was intended to facilitate the installation of recording demand meters and other forms of "smart" meter technology by EGSs. The rider became effective in 1999, but has not been used since it was introduced. Moreover, the Commission has approved a Smart Meter Deployment Plan for the Companies pursuant to Section 2807(f) of the Public Utility Code.3 Under the Smart Meter Deployment Plan, the Companies will install advanced metering infrastructure and will provide smart meters for all customers. Consequently, the rationale for Rider F – namely, that non-utility suppliers could furnish smart meters for which Customers should receive a bill credit – has been eliminated by the addition of Section 2807(f) to the Public Utility Code.

- **Rider H – Short Term Demand Utilization**: Rider H is a legacy of "bundled" service dealing principally with generation demand costs. Specifically, it allowed large commercial and industrial customers to increase their demand, with advance notice, for limited periods of time, without ratcheting up their billing demand for all purposes. Following the restructuring of the electric industry in Pennsylvania, generation is no longer a "bundled" service and instead is provided by third-party suppliers. Accordingly, the service that Rider H offers is not consistent with the current unbundled rate environment. Large commercial and industrial customers seeking the kind of flexible demand option that Rider

[3] 66 Pa.C.S. § 2807(f).

H provided in the bundled rate environment can now shop for similar generation service options from EGSs. If such customers choose to remain on default service, they can obtain a similar form of service under the Hourly Price to Compare Default Service Rider.

- **Rider J – Consumer Education Program:** Rider J provides for the recovery of costs incurred by the Companies to implement their Consumer Education Plans approved by the Commission at Docket Nos. M-2008-2032261 and M-2008-2032262. The Companies' Consumer Education Plans have run their course and are no longer in effect. Therefore, the rider is no longer being used to recover those costs.

- **Rider K – Voluntary Prepayment Plan:** The Voluntary Prepayment Plan Rider offered an optional service to mitigate the anticipated rate impact of the transition to market-based electric generation supply rates when generation rate caps expired. For a period of time before generation rate caps expired, customers could pay monthly amounts exceeding their billing obligations. Those payments were summed and maintained as individualized customer balances that accrued interest and were credited to customers' bills during the period April 1, 2009 through December 31, 2010. This program has expired. Therefore, Rider K should be eliminated.

Q. Please identify the riders being eliminated from Penn Power's tariff.

A. The five existing riders being eliminated from Penn Power's proposed tariff and the reasons for eliminating them are as follows:

- **Consumer Education Program Cost Recovery Rider:** This rider is comparable to Met-Ed's and Penelec's Rider J and is being eliminated from Penn Power's proposed tariff for the same reason Rider J is being eliminated from the Met-Ed and Penelec proposed tariffs, as previously explained.

- **Residential Service Optional Controlled Service Rider, General Service – Secondary Voltages Optional Controlled Service Rider, and Commercial and Industrial Optional Heating Rate:** Like Rider H – Short Term Demand Utilization for both Met-Ed and Penelec, these riders are vestiges of the bundled rate environment that were designed to provide either interruptible generation service or discounted generation service for electric heating and process heating applications. With the advent of full unbundling, generation service is now provided by third-party suppliers and customers seeking the kinds of rate options for generation service offered by these riders should obtain them from EGSs. Any future interruptible programs offered by the Companies would be made available only as part of a Commission-approved Energy Efficiency and Conservation Plan.

- **Facility and Financing Assistance Arrangement Rider:** This rider, which is part of the Community and Customer Partnership Program, is being eliminated because it has not been used by customers for at least the last five years. One of the objectives of the program was to improve energy efficiency, which Penn Power currently does through its Energy Efficiency and Conservation Plan filed with, and approved by, the Commission pursuant to Section 2806.1 of the Pennsylvania Public Utility Code.

Q. Please identify the riders being eliminated from West Penn's existing generally applicable tariff.

A. The eleven existing riders being eliminated from West Penn's generally applicable tariff and the reasons for eliminating them are as follow:

- **Consumer Education Charge:** This rider is comparable to Met-Ed's and Penelec's Rider J and is being eliminated from West Penn's generally applicable proposed tariff for the same reason Rider J is being eliminated from the Met-Ed and Penelec proposed tariffs, as previously explained.

- **FirstEnergy Merger Credit:** This rider provided a credit to residential customers for net savings resulting from the FirstEnergy/Allegheny merger. The credit terminated as of April 25, 2014; therefore, the rider is no longer in use and should be eliminated.

- **Alternative Generation Rider:** This rider is comparable to Met-Ed's and Penelec's Rider B and is being eliminated from West Penn's generally applicable proposed tariff for the same reason Rider B is being eliminated from the Met-Ed and Penelec proposed tariffs, as previously explained.

- **Opportunity Power Rider, Curtailment Service Rider, Experimental Shoulder-Peak Rider, and Experimental Saturday and Holiday Load Option Rider:** Like Rider H – Short Term Demand Utilization for both Met-Ed and Penelec, each of these riders is a vestige of the bundled rate environment. Each rider was designed to allow large commercial and industrial customers to use electricity without incurring the full amount of otherwise applicable demand charges either because the customer's usage would be interruptible or curtailable, or because energy usage would occur during non-peak or shoulder-peak periods. These riders were designed for use at a time when EDCs were providing bundled generation service. With the advent of full unbundling, generation service is now provided by third-party suppliers and customers seeking the kinds of rate options for generation service offered by these riders can obtain them from EGSs. If such customers choose to remain on default service, they can obtain a similar form of service under the Hourly Price to Compare Default Service Rider.

- **Surge Suppression Service:** This is a voluntary rider that allowed customers to purchase surge suppression equipment from the Company. The Commission approved Met-Ed's and Penelec's elimination of a

similar program in 2006, and West Penn is eliminating this rider from its proposed tariff to maintain consistency with the service offerings of the other Companies.

- **Wind Energy Service Rider**: This is a voluntary rider that allowed customers to purchase Wind Energy Blocks for the purpose of promoting the development of wind energy. The rider was approved for a limited time and, by its terms, expired on December 31, 2010. Renewable resources can now be purchased from EGSs and are also supplied in accordance with the Renewable Portfolio Standards established by Act 213 of 2004. Therefore, this rider is no longer effective or necessary.

- **Critical Peak Rebate and Critical Peak Pricing Default Service Riders:** These riders were introduced as part of the West Penn Power Energy Efficiency and Conservation Plan at Docket M-2009-2093218. The Critical Peak Rebate program was available to residential customers through funding created by West Penn's Energy Efficiency and Conservation charge. The program terminated on May 31, 2013, with the conclusion of Phase One of West Penn's Energy Efficiency and Conservation Plan. The Critical Peak Pricing Default Service Rider provided commercial customers an alternative default service option during Summer Periods, defined as June 1, 2012 through September 20, 2012. Customers were offered lower rates per kWh in exchange for agreeing to pay higher rates per kWh during designated Critical Peak periods. The program was designed to shift load from the on-peak to the

off-peak period as part of the Energy Efficiency and Conservation Plan, but was superseded when West Penn's Hourly Pricing Default Service Rider was made available to commercial customers beginning in June of 2013. Consequently, these riders are being eliminated.

Q. Please describe the riders being eliminated from the West Penn/PSU Tariff.

A. West Penn is proposing to eliminate the FirstEnergy Merger Credit, the Consumer Education Charge, and the Wind Service Rider from the West Penn/PSU Tariff for the same reasons those riders are being removed from the generally applicable West Penn tariff.

Q. In addition to the changes noted above, are you sponsoring modifications to any other of the Companies' existing riders?

A. Yes. Penn Power's existing USC Rider contains provisions that: (1) impose a ceiling on the amount of administrative expenses that may be spent on its Customer Assistance Program ("CAP"); and (2) refer to the application of an annual credit to actual expenses for each Reconciliation Year. These provisions are being removed in order to make Penn Power's USC Rider consistent with those of Met-Ed and Penelec. The provisions being eliminated were originally added to Penn Power's USC Rider because Penn Power implemented its USC Rider outside of a base rate proceeding and, therefore, the recovery of certain costs previously included in base rates might, as a consequence, be affected. The provisions are no longer necessary because all such costs and their recovery will be properly aligned as part of this proceeding.

Q. Are the riders you describe above as being eliminated, relocated or modified the only changes to the Companies' existing riders being made by the proposed tariffs?

A. No, they are not. As explained by Mr. Siedt in Met-Ed/Penelec/Penn Power/West Penn Statement No. 4, Time-Of-Use Default Service Riders are being added to the proposed tariffs of Met-Ed and Penelec similar to comparable Commission-approved provisions in Penn Power's Time of Use Default Service Rider and West Penn's Time of Use Rider. Additionally, as explained by Laura W. Gifford in Met-Ed/Penelec/Penn Power/West Penn Statement No. 7, an uncollectible accounts component is being added to the Default Service Support Rider for West Penn, accompanied by a corresponding reduction in the uncollectible accounts expense recovered in base rates to make West Penn's uncollectible expense treatment consistent with the other Companies.

C. New Proposed Tariff Riders

Q. Are any new riders being proposed for addition to the Companies' tariffs?

A. Yes. As, as I previously noted, the Companies are proposing to add a Storm Rider to each of their tariffs, including the West Penn/PSU Tariff, and West Penn is proposing to adopt a USC Rider, comparable to the ones already in effect for Met-Ed, Penelec and Penn Power, to be included in its generally applicable tariff. Both new riders are described below.

1. Storm Rider

Q. What is the purpose of the proposed Storm Rider?

A. The proposed Storm Rider would add to the Companies' tariffs an adjustment clause, under Section 1307(a) of the Pennsylvania Public Utility Code,[4] to impose a charge or credit on Customers' bills to reflect the difference, on an annual basis, between the respective storm damage expenses recovered in the Companies' base rates and the actual storm damage expenses incurred by the Companies. The Storm Riders would provide for timely recovery of actual storm damage expenses -- neither more nor less. In that way, the proposed riders will eliminate the risk created by recovering such costs only in base rates that a Company could recover too much or too little, or that recovery could be unreasonably delayed. Storm damage expenses are appropriate for recovery under a Section 1307 adjustment clause because they are valid operating expenses, can be clearly identified, are volatile (exhibit substantial variability from year to year), are outside a utility's control, are material in amount, and are likely to escape full recovery if a Section 1308 base rate proceeding were the only way to reflect such costs in customer rates.

Q. What level of storm damage expenses is recovered in the Companies' base rates?

A. Consistent with prior Commission practice, the Companies' base rates have been designed to recover only a normal level of storm damage expenses. Stated another way, base rates are not designed to reflect experience that deviates

[4] 66 Pa.C.S. § 1307(a).

materially from a historically derived baseline of "normal" storm damage expenses. As a consequence, if a low level of storm activity occurs in a given year, base rates may reflect more than actual costs. On the other hand, the costs of extraordinary weather events, such as major storms, are not reflected in the level of expenses recovered in base rates. Historically, when utilities experienced extraordinary storm damage expenses, they have petitioned the Commission for approval to defer those expenses for accounting purposes and to request recovery in a subsequent base rate case. As a consequence, where such approval is granted, the costs identified as extraordinary are recorded in a deferred account and not recorded as a charge against income in the year they are incurred.

Q. How is a normal level of storm damage expenses to be recovered in base rates determined?

A. As I explained above, extraordinary storm damage expenses are generally recorded in a deferred account, with the Commission's prior approval. The non-deferred amounts represent the level of expenses that are not extraordinary and, therefore, form the basis for determining a normalized level of storm damage expense. To illustrate, Met-Ed, in this proceeding, has claimed for recovery in base rates a normal level of storm damage expense for the fully projected future test year of $6.6 million, as shown in Met-Ed Exhibit RAD-63 and described in greater detail by Richard A. D'Angelo in Met-Ed/Penelec/Penn Power/West Penn Statement No. 2. The Company's claim approximates the historical average of Met-Ed's actual storm damage costs, as shown on Met-Ed Exhibit RAD-63, less the amounts deferred with prior Commission approval, as shown on Met-Ed

Exhibit RAD-2 at page 24, line 5. The fully projected future test year claims for storm damage expense to be recovered in base rates are set forth in Exhibits RAD-63 for each of the Companies, and the deferred storm damage costs are set forth on page 24 of Exhibit RAD-2 for each of the Companies.

Q. What are the relevant terms of the proposed Storm Riders?

A. All of the terms of the proposed Storm Riders are contained in Rider B for each Company, which is set forth in the portions of the Companies' proposed tariffs that I specifically identified in Section I of my testimony. The Storm Rider provides a formula for calculating a charge or credit to customers' bills on a per-kWh basis. The heart of the formula is the difference between the amount of annual storm damage expense reflected in a Company's base rates and the amount of storm damage expense incurred during the preceding calendar year for the categories of costs identified in the rider. Additionally, in each successive year, the computation will include an "E" factor reflecting the over or under-collection of actual storm damage costs that result from billing the Storm Damage Charge during the Reconciliation Year (November 1 through October 31, as appropriately adjusted for the first year the rider is in effect). In other words, the Storm Rider will be fully reconciled each year. The costs, derived in the manner I described, are divided by projected retail sales and grossed-up for gross receipts tax.

The Storm Damage Charge is to be calculated separately for each of four Rate Classes that are defined as follows: (1) Rate Class 1 consists of the residential rate schedules for each Company; (2) Rate Class 2 consists of commercial and

industrial customers served on rate schedules primarily used by those customers served at secondary voltages; (3) Rate Class 3 consists of customers receiving service on rate schedules requiring that they take service at primary voltage; and (4) Rate Class 4 consists of customers served on rate schedules primarily used by customers served at transmission voltage. The Company-specific rate schedules included in each rate class are included in each Company's specific Rider F in its proposed tariff(s).

Total costs for each Company are to be allocated among Rate Classes in accordance with applicable allocation factors derived from a Company's cost of service study in a contemporaneous or last prior base rate case. Similarly, retail sales (the divisor in the formula) are to be developed by Rate Class.

The Computation Year for Rider F is the twelve months ending December 31 (with appropriate adjustment for the first year the riders are in effect). The Reconciliation Year is, as noted above, the twelve months ending October 31 (with appropriate adjustment for the first year the riders are in effect). Each annual calculation of the Storm Damage Charge is to be filed with the Commission by December 1 of each year to become effective on January 1. The riders authorize interim adjustments to be filed on thirty days' notice if the charge, left unchanged, would result in a material over or under-collection. Additionally, the operation of the Storm Damage Charge Riders will be subject to Commission supervision, review and audit.

Q. Met-Ed and Penelec proposed a Storm Damage Rider in their 2006 base rate cases at Docket Nos. R-00061366 and R-00061367 before the Commission. What was the disposition of their proposed riders at that time?

A. Their proposals were opposed by various parties. The Administrative Law Judges ("ALJs") in that consolidated proceeding recommended that the proposed Storm Damage Riders not be approved. No party took exception to the ALJs' recommendation, which the Commission, therefore, adopted in its Final Order issued on January 11, 2007.

Q. Has anything occurred since the Commission issued its Final Order in the Met-Ed/Penelec 2006 base rate cases that indicates Commission support for an adjustment clause to recover storm damage expenses?

A. Yes. In its December 28, 2012 Final Order in PPL Electric Utilities Corporation's ("PPL") base rate case at Docket No. R-2012-2290597, the Commission directed PPL to "file a rider for storm damage expense recovery within ninety days of the entry of this Opinion and Order," and also directed PPL to meet with the parties to that proceeding to discuss the terms of such a rider. Following those discussions, on March 28, 2013, PPL filed a proposed Storm Damage Expense Rider. After receiving comments from the parties, the Commission entered an order on April 3, 2014 approving PPL's Storm Damage Expense Rider subject to certain modifications. In that order, the Commission found that storm damage expenses were appropriate for recovery under a Section 1307 adjustment clause. In particular, the Commission found that "there can be little reasonable debate over the fact that the Commonwealth has, as of late, experienced weather phenomena

of increased frequency, power, and duration" (p. 15). The Commission's finding is consistent with the Companies' experience, as evidenced by the pattern and levels of annual storm damage expense shown in Exhibit RAD-63 for each of the Companies. In the same vein, Met-Ed and Penelec each had made a single request for deferral of extraordinary storm damage expenses prior to 2006. However, since that time, the Companies have experienced major summer and winter storms and, as a result, have submitted three petitions for deferral of extraordinary storm expenses over a four-year period, each of which were granted.

Q. Did the Commission make any additional findings in the PPL order regarding recovery of storm damage expenses under a Section 1307 adjustment clause?

A. Yes, it did. In that order, the Commission also found that:

- Storm damage expenses are not within the control of a utility ("Nature is the primary director of the scale and scope of these matters – not utility management.") (p. 22);

- Storm damage expenses are recoverable utility expenses that can be readily identified ("In addition, storm damage expense is unquestionably above-the-line expense. Storm damage expenses, properly isolated from costs flowing into base rates, are easily identified expenses.") (p. 23);

- Storm damage expenses are variable (p. 21) and difficult to project for purposes of prospective recovery in base rates ("Similarly, projecting the vagaries of weather in a future test year is fraught with the potential for error: utilities may recover too much too soon or too little, too late.") (p. 15);

- Storm damage expenses represent "a significant imposition on the opportunity to earn an approved rate of return" (p. 23); and
- Recent storm activity warrants the adoption of a storm cost recovery rider ("We believe that the benefit of implementing the SDER is particularly appropriate given the size of recent storm events and our increasing emphasis on enhanced system reliability . . .") (p. 23).

2. West Penn's USC Rider

Q. Please describe the Companies' Universal Service programs.

A. Each of the Companies has in place the following Universal Service programs: (a) the Customer Assistance Referral and Evaluation Services Program ("CARES"); (b) CAP; (c) Dollar Energy Fund; (d) Gatekeeper; and (e) WARM (the Companies' Low Income Usage Reduction Program ("LIURP")). These programs allow the Companies to serve the needs of low-income customers through case management, referrals to other human service programs, monthly bill subsidies and discounts, debt forgiveness credits, payment counseling, cash assistance grants, weatherization measures, and energy conservation education.

Q. How are the Companies currently recovering Universal Service costs?

A. Met-Ed, Penelec and Penn Power each have a USC Rider in their respective tariffs that provides a reconcilable adjustment clause as the means of recovering these costs. West Penn currently recovers Universal Service program costs through base rates.

Q. Is West Penn proposing a USC Rider to recover Universal Service program costs?

A. Yes. West Penn proposes to adopt a USC Rider, which will make the form of its cost recovery consistent with Met-Ed, Penelec and Penn Power. In fact, West Penn's USC Rider is modeled after the Commission-approved USC Riders that are already in effect for Met-Ed and Penelec. Consequently, approving the proposed USC Rider will extend to West Penn the same form of cost recovery that has been used successfully, with Commission approval, by the other Companies for a number of years.

West Penn's proposed USC Rider, which is included in its proposed generally applicable tariff in this case, will provide for full and timely recovery of Universal Service program costs. In that way, the proposed rider will enable West Penn to increase expenditures and enhance existing programs in response to changes in economic conditions in the communities it serves and to make changes in those programs that the Commission or other agencies may determine are necessary to properly assist West Penn's low-income customers. Thus, the USC Rider will remove the obstacle created by limiting available funding to what base rates

recover, which constrains West Penn's ability to respond promptly to economic hardships that may arise unexpectedly within its service area.

Q. Has West Penn's Universal Service cost recovery been adequate?

A. No. West Penn has not consistently recovered its Universal Service program costs in the past and is not doing so currently. During 2013, West Penn's CAP and WARM programs were overspent by almost 62%, or $4.9 million more than the $7.9 million provided under the terms of the 1998 Settlement of West Penn's restructuring proceeding, which established its initial level of base rate cost recovery for Universal Service programs.

Q. Do the per-customer benefits provided under West Penn's Universal Service programs need to be expanded to match the benefit levels being provided by the other Companies?

A. Yes, they do. West Penn's portfolio of Universal Service programs is a vital safety net for low-income customers and should be adequately funded. To that end, West Penn would support modifying its Universal Service programs to align with the other Companies programs, provided its form of cost recovery is also revised to conform with the form of cost recovery already in place for those Companies.

Q. What level of annual expense would West Penn incur if its Universal Service programs were modified to provide the per-customer benefit levels offered by comparable programs at the other Companies?

A. Modifying West Penn's Universal Service programs to match the benefit levels of the programs in place at the other Companies would cause West Penn to incur an annual expense of $29,521,027. The specific program components and the costs associated with each component at benefit levels that align with those of the other Companies are set forth in West Penn Exhibit KLB-2.

The indicative increases shown in West Penn Exhibit KLB-2 for West Penn's Customer Assistance Program (CAP) and Customer Assistance Referral and Evaluation Services Program (CARES) would result from: (1) lowering the percent-of-income requirements for CAP participants to align with the CAPs of the other Companies, which will reduce eligible customers' bill burden and could increase the annual CAP benefit expense borne by West Penn; and (2) increasing the maximum amount of bill subsidies to align with the other Companies' Universal Service programs, which would increase the annual CAP benefit expense West Penn incurs for the participants who currently receive the maximum levels but, nonetheless, need additional assistance. The increases in expense associated with the LIURP and WARM program shown in West Penn Exhibit KLB-2 would be needed to allow West Penn's program to mirror the level of per-customer benefits provided by the same programs at the other Companies.

Q. Is West Penn seeking to recover from customers the entire amount of $29.5 million in annual expense shown in West Penn Exhibit KLB-2?

A. No, it is not, for reasons that relate to the terms of the Commission-approved Joint Petition for Partial Settlement in the proceeding for approval of the FirstEnergy/Allegheny merger at Docket Nos. A-2010-2176520 and A-2010-2176732 ("Merger Settlement"). Specifically, under Paragraph Nos. 20 and 22, West Penn agreed to increase its level of spending for Universal Service programs by $750,000 per year for CAP and $1,800,000 in Year 5 for LIURP and to not recover those increased levels of expenditures from customers during the five-year period after the consummation of the FirstEnergy/Allegheny merger. The merger closed on February 25, 2011, consequently, the fifth calendar year following the consummation of the merger is the twelve months ending December 31, 2015. The Universal Service program costs used to calculate the first year charge are for the twelve months ending April 30, 2016. Consequently, I have reduced the total expense level of $29,521,027 by $1,700,000 to reflect a pro rata portion of the amounts not recoverable under the terms of the Merger Settlement for May 2015 to December 2015 ($2,550,000 x 8/12 of 2015). Therefore, West Penn is claiming $27,821,027 for recovery from customers the first year the USCR would be in effect, which would begin on May 1, 2015.

Q. Please describe the relevant terms of West Penn proposed USC Rider.

A. Rider C of West Penn Company Exhibit 1 is West Penn's proposed USC Rider, which contains all of the terms for calculating and applying the Universal Service Charge ("USC"). I will summarize the relevant terms.

The USC Rider develops a USC based upon an estimate of the costs to be incurred by the Company to administer and provide benefits under West Penn's Universal Service programs for the Computational Year, which, except for the first year of effectiveness, is the period January 1 through December 31. The various program components for which costs are to be recovered under the USC Rider are CARES, CAP, Dollar Energy Fund Administration, Gatekeeper, and WARM. The USC will be applied on a per-kWh basis only to Residential distribution service sales under the Company's tariff.

Costs and revenues under the USC Rider will be reconciled each year, and an over or under collection, as applicable, including interest at the statutory rate, will be included in the "E" factor of the charge. The USCR will also be subject to review and audit by the Commission.

Q. What is the USC West Penn proposes to bill effective May 1, 2015?

A. Based on a forecast of normalized Universal Service program costs for the twelve months ending April 30, 2016, West Penn proposes to bill $0.00406 per kWh to residential rate classes. Details of the computations are set forth in West Penn Exhibit KLB-2.

Q. Why is West Penn proposing to recover Universal Service costs only from Residential classes?

A. In the Met-Ed and Penelec 2006 base rate cases, those Companies were authorized to implement USCRs that would impose a USC only on Residential

customers. The Commission's determination in those cases was consistent with its final order in the proceeding captioned *Customer Assistance Program Funding Levels and Cost Recovery Mechanisms*, which was entered on December 18, 2006 at Docket No. M-00051923. Additionally, Penn Power was authorized to implement a USC to be billed only to Residential customers by the Commission's final order at Docket Nos. R-0072347 and M-00072023 entered on April 11, 2008. Consistent with the Commission's decisions in those cases, West Penn is proposing to recover all Universal Service program costs only from residential customers.

Q. If the USC Rider is not adopted by the Commission, what alternative approach for recovery of Universal Service costs are you proposing?

A. If the Commission determines that the USC Rider is not the appropriate mechanism for recovering Universal Service costs, those costs would need to be included in the Company's operating expenses for the fully projected future test year to be recovered in base rates. West Penn Exhibit KLB-2 at line 5, column 3, shows the expense claim of $27,821,027. Grossed up for gross receipt tax, the revenue requirement would be $29,565,378 ($27,821,027 x 1.062699), which should be included in operating expenses to be recovered in West Penn's base rates. If the USC Rider is not approved, the Company will limit funding for Universal Service programs to the amounts it is authorized to recover in base rates.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Resume: Education and Experience of Kimberlie L. Bortz

Education:

Bachelor of Science Degree in Accounting - University of Maryland

Professional Certification:

Certified Public Accountant - Pennsylvania

Experience:

1989 – 1992	Senior Accountant - Deloitte & Touche
1992 – 1994	Senior Auditor - GPU Service Corporation
1994 – 1996	Financial Analyst - Metropolitan Edison Company
1996 – 1997	Sales and Marketing Team Lead - GPU Energy
1997 – 1999	Accounting Team Lead - GPU Advanced Resources
1999 – 2001	Comptroller - GPU Advanced Resources
2001 – 2004	Manager, Met-Ed Region Business Services - FirstEnergy Service Company
2004 – 2007	Manager, Customer Service Business Services - FirstEnergy Service Company
2007 – 2012	Director, PA Business Services - FirstEnergy Service Company
2012 – 2014	Accounting Lead, Financial Transformation Project - FirstEnergy Service Company
2014 – Present	Rates Advisor, Pennsylvania Rates and Regulatory Affairs - FirstEnergy Service Company

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT IV-B-1:

"Provide a description of changes proposed for the new tariff:

1. For each rate schedule proposed to be modified."

FILING REQUIREMENT IV-B-2:

"Provide a description of changes proposed for the new tariff:

2. For each rate schedule proposed to be deleted."

FILING REQUIREMENT IV-B-3:

"Provide a description of changes proposed for the new tariff:

2. For each new rate schedule proposed to be added."

RESPONSES:

The information responsive to these filing requirements is contained in Tariff Electric PaPUC No. 52. Refer to the testimony and exhibits in Statement No. 1, the direct testimony of Charles V. Fullem; Statement No. 3, the direct testimony of Kimberlie L. Bortz; Statement No. 4, the direct testimony of Kevin M. Siedt; and Statement No. 7, the direct testimony of Laura W. Gifford which presents all of the changes proposed in the new tariffs.

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 8

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2014-2428745

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. R-2014-2428743

PENNSYLVANIA POWER COMPANY
DOCKET NO. R-2014-2428744

WEST PENN POWER COMPANY
DOCKET NO. R-2014-2428742

Direct Testimony
of
Christopher D. Ciccone

List of Topics Addressed

LED Street Lighting

DIRECT TESTIMONY
OF
CHRISTOPHER D. CICCONE

Q. Please state your name and business address.

A. My name is Christopher D. Ciccone. My business address is 2800 Pottsville Pike, Reading, Pennsylvania 19612.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company as an Analyst II in the Rates and Regulatory Affairs Department – Pennsylvania.

Q. And what are your responsibilities as an Analyst II?

A. Generally, the Rates and Regulatory Affairs Department provides regulatory support for Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power"), and West Penn Power Company ("West Penn") (collectively, the "Companies"). I report to the Manager – Rates and Regulatory Affairs – Pennsylvania and I am responsible for the development and preparation of the Companies' accounting and financial data in support of rate-related matters before the Pennsylvania Public Utility Commission and New York Public Service Commission including the preparation of statements and reports addressing, among other things, energy costs, shopping statistics and other customer matters. Also, I am responsible for the administration of the Companies' retail tariffs, the development of retail electric rates and the promulgation of rules and regulations ensuring uniform tariff administration and

interpretation. My work experience and educational background are more fully described in Appendix A attached to this testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to outline proposed tariff provisions to allow the Companies to implement new light emitting diode ("LED") street lighting services. I will first describe the lighting service and then explain how the Companies propose to recover the costs associated with the offering.

Q. Mr. Ciccone, have you prepared exhibits to accompany your testimony?

A. Yes. The following exhibits or portions of exhibits were prepared by me and are described in detail in my testimony: Met-Ed/Penelec/Penn Power/West Penn CDC-1; Exhibits CDC-2 for each of the Companies; pp. 100-102 of Met-Ed Company Exhibit 1; pp. 103-105 of Penelec Company Exhibit 1; pp. 96-98 of Penn Power Company Exhibit 1; and pp. 149-151 of West Penn Company Exhibit 1 (collectively, "Companies' Exhibits 1").

Q. What is the purpose of the proposed new LED street lighting offerings?

A. The offerings were developed in response to customer requests for additional LED street lighting options. Met-Ed and Penelec have each previously introduced tariff provisions offering customer owned and maintained LED lighting.[1] In light of continued customer interest in LED lighting, the Companies would now like to offer Company owned and

[1] Metropolitan Edison Company. Electric Pa. P.U.C. No. 51. Street Lighting Service - Provision G. Page 130. Pennsylvania Electric Company. Electric Pa. P.U.C. No. 80. Municipal Street Lighting Service – Provision G (4). Page 139.

maintained LED street lighting. These proposed new offerings are outlined in the schedules found in Companies' Exhibits 1 at the following pages: pp. 100-102 (Met-Ed); pp. 103-105 (Penelec); pp. 96-98 (Penn Power); and pp. 149-151 (West Penn).

Q. What customers will be eligible for this offering?

A. As a general matter, municipalities, local, state and federal governmental bodies, community associations, and public authorities will be eligible. On a Company-specific basis, eligibility is as follows:

Met-Ed: open to any customer currently receiving service under a street lighting schedule interested in updating their Street Lighting Service or Ornamental Street Lighting Service.

Penelec: open to any customer currently receiving service under a street lighting schedule interested in updating their High Pressure Sodium Vapor Street Lighting Service or Municipal Street Lighting Service.

Penn Power: open to any customer currently receiving service under a street lighting schedule interested in updating their Street Lighting Service (Sodium Vapor), Street Lighting Service (Sodium Vapor – Divided Ownership), or Street Lighting Service (Mercury Vapor).

West Penn Power: open to any customer currently receiving service under a street lighting schedule interested in updating their Street Lighting Service – Schedule 51, Street and Area Lighting – Schedule 53, Street Lighting Service – Schedule 54, Street

Lighting Service – Customer-Owned Equipment – Schedule 56, Outdoor Lighting Equipment and Maintenance Service – Schedule 57, or Mercury Vapor Street and Highway Lighting Service – Schedule 71.

Q. Will a contract be necessary to sign up for this offering?

A. Yes, the initial term for all contracts will be ten years. Contracts may then be renewed for successive one year terms.

Q. Will participating customers be able to choose an alternative electric generation supplier?

A. Yes. Participating customers will be free to shop for their generation and market based transmission services.

Q. What type of fixture heads will be available under these offerings?

A. The Companies propose to offer Cobra, Acorn, and Colonial styled fixture heads. The minimum number of fixture heads required for any installation will be twelve.

Q. Why do the Companies propose offering group installations?

A. Offering group installations of twelve or more is more cost effective as compared to installing single fixtures.

Q. After installation, who is responsible for the maintenance of these lights?

A. Once installed, the Companies will own and maintain the light fixtures.

Q. What is the forecasted impact on revenues due to the introduction of LED street lighting?

A. Since this is a new product offering and the level of customer participation is uncertain, it is difficult to quantify any impact on revenues at this point in time and would be speculative. Therefore, a revenue analysis cannot be completed.

Q. How are the Companies proposing to recover costs associated with the LED street lighting offering?

A. The Companies propose to recover costs through a fixed monthly charge for each LED fixture. The proposed monthly charges, by fixture and by Company, are provided in Met-Ed/Penelec/Penn Power/West Penn Exhibit CDC-1.

Q. How did the Companies calculate the fixed charges?

A. Exhibits CDC-2 contain all of the supporting calculations and data used to determine the monthly fixture cost for each light offered. Page 1 contains the cost of service for this new offering. Pages 2 thru 9 display the Levelized Payment calculations for the eight fixtures offered. Page 10 shows the installation cost for each fixture. Page 11 contains supporting data for the Other Distribution Plant Factor and Other Distribution O&M Factor. Page 12 displays supporting details for the General Property Factor. Page 13 contains supporting details for the Customer Expense Factor. Page 14 shows supporting work for the Property Tax Factor. Page 15 contains the details for the Overall Rate of Return. Page 16 displays a table of tax depreciation rates based on the Modified Accelerated Cost Recovery System (MACRS).

Q. Why did the Companies perform a separate cost of service study for the LED street lighting instead of incorporating the new offerings into the Cost of Service Study sponsored by Hillary Stewart in Met-Ed/Penelec/Penn Power West Penn Power Statement No. 5?

A. The Companies are requiring ten-year contracts for all new LED street lighting services, and therefore wanted to use a levelized fixed charge rate approach instead of the traditional net plant approach incorporated in the Cost of Service Study sponsored by Ms. Stewart. By using the levelized fixed charge rate approach, the costs of LED streetlights are spread over the ten-year period and the resulting customer charges are more affordable in the early years as opposed to a net plant approach. In addition, by requiring a ten-year commitment for the new fixtures, the Companies are protected against stranded cost risk. For these reasons, I believe the levelized fixed charge rate cost support is more appropriate in that it benefits both customers and the Companies.

Q. Is the monthly fixture charge the only cost to participating customers?

A. No. All Riders applicable to the Companies' existing lighting services will also apply to the LED Street Lighting Services, as detailed in the proposed tariff schedules provided in the previously-referenced excerpts to Companies' Exhibits 1. In addition, if a customer wishes to replace their current lighting during the initial ten year term with Company-owned LED lighting under one of the LED Street Lighting Services, the customer will be responsible for any remaining costs of the customer-owned lighting as well as any early termination or removal fees that may apply.

Q. How were the fixed kWh usages in the proposed tariff schedules determined for this unmetered service?

A. The lighting units will operate from dusk to dawn, which results in approximately 4,200 hours of operation per year. The respective lamp wattage is multiplied by the 4,200 hours of operation per year, divided by twelve months, and then divided by 1,000 to be converted into kilowatt-hours. This calculation establishes the fixed monthly kWh usage for each fixture.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Resume: Education and Experience of Christopher D. Ciccone

Education:

2010	Bachelor of Science Degree in Economics – Pennsylvania State University, State College, Pennsylvania
2012 – Present	Various utility industry conferences and seminars (e.g., EEI Advanced Rates Course, PJM 101: The Basics)

Experience:

5/10 – 8/10	House Republican Appropriation Committee Intern – Harrisburg, PA
9/10 – 1/12	Guest Services – Hotel State College & Company – State College, PA
2/12 – Present	State Regulatory Analyst – Rates & Regulatory Affairs – Pennsylvania – FirstEnergy Service Corporation

Assisted in development and preparation of in the following rate-related proceedings:

Pennsylvania Public Utility Commission:

Docket Nos.	P-2011-2273650	P-2011-2273668	P-2011-2273669
	P-2011-2273670	M-2012-2334387	M-2012-2334392
	M-2012-2334395	M-2012-2334398	M-2012-2303494
	M-2012-2303547	M-2012-2303545	M-2013-2360494
	M-2013-2360493	M-2013-2360497	M-2014-2419717
	M-2014-2419719	M-2014-2419780	M-2014-2419764
	M-2014-2420515	M-2014-2420507	M-2014-2420525

New York State Public Service Commission:

Case No. 13-E-0067

Metropolitan Edison Company
LED Street Lighting Service
Rate Summary

Line No.	Description	Cobra Head 50W 4000L	Cobra Head 90W 7000L	Cobra Head 130W 11500L	Cobra Head 260W 24000L	Acorn 50W 2500L	Acorn 90W 5000L	Colonial 50W 2500L	Colonial 90W 5000L
1	Install Cost	**$ 456.71**	**$ 572.11**	**$ 608.17**	**$ 939.93**	**$ 1,209.07**	**$ 1,277.70**	**$ 728.37**	**$ 800.85**
2	Other Dist. Plant	$ 79.38	$ 99.44	$ 105.71	$ 163.38	$ 210.16	$ 222.09	$ 126.60	$ 139.20
3	General Plant	$ 38.53	$ 48.27	$ 51.31	$ 79.30	$ 102.00	$ 107.79	$ 61.45	$ 67.56
4	Total Install	$ 574.62	$ 719.81	$ 765.18	$ 1,182.60	$ 1,521.22	$ 1,607.58	$ 916.42	$ 1,007.62
5	Fixed Charge Rate:	13.50%	13.50%	13.50%	13.50%	13.50%	13.50%	13.50%	13.50%
6	Total Revenue Requirement:	$ 1,073.93	$ 1,345.28	$ 1,430.08	$ 2,210.20	$ 2,843.06	$ 3,004.46	$ 1,712.73	$ 1,883.17
7	Revenue Requirement NPV:	$ 661.94	$ 829.20	$ 881.46	$ 1,362.31	$ 1,752.39	$ 1,851.87	$ 1,055.68	$ 1,160.74
8	Annual Levelized Payment:	$ 77.58	$ 97.19	$ 103.31	$ 159.67	$ 205.39	$ 217.05	$ 123.73	$ 136.05
9	Monthly Fixture Charge	$ 6.47	$ 8.10	$ 8.61	$ 13.31	$ 17.12	$ 18.09	$ 10.31	$ 11.34
10	Gross Receipts Tax	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
11	Monthly Fixutre Charge	**$ 6.87**	**$ 8.61**	**$ 9.15**	**$ 14.14**	**$ 18.19**	**$ 19.22**	**$ 10.96**	**$ 12.05**

Metropolitan Edison Company
Levelized Payment Calculation

Cobra Head / 4000L / Group Install

Line No.	Year	Undepreciated Balance	Book Depr. Expense	Tax Depreciation Rate	Tax Depreciation Expense	DIT Expense	ADIT	Rate Base Balance	Interest Expense	Equity Return	CIT Expense	Property Taxes	Customer Expense	Distribution O&M	Total Fixed Chgs	Present Value	Levelized Payment
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(N)	(O)	(P)	(Q)	(R)
1	0	$575															
2	1	$536	$38	14.29%	$82	$18	$18	$518	$14	$28	$2	$0	$6	$3	$110	$102	$78
3	2	$498	$38	24.49%	$141	$42	$61	$437	$11	$24	-$26	$0	$6	$3	$100	$86	$78
4	3	$460	$38	17.49%	$101	$26	$86	$373	$10	$20	-$11	$0	$6	$3	$92	$73	$78
5	4	$421	$38	12.49%	$72	$14	$100	$321	$8	$17	-$1	$0	$6	$3	$86	$63	$78
6	5	$383	$38	8.93%	$51	$5	$106	$277	$7	$15	$5	$0	$6	$3	$81	$55	$78
7	6	$345	$38	8.92%	$51	$5	$111	$234	$6	$13	$4	$0	$6	$3	$76	$48	$78
8	7	$306	$38	8.93%	$51	$5	$117	$190	$5	$10	$2	$0	$6	$3	$71	$41	$78
9	8	$268	$38	4.46%	$26	-$5	$111	$157	$4	$9	$11	$0	$6	$3	$67	$36	$78
10	9	$230	$38	0.00%	$0	-$16	$95	$134	$4	$7	$21	$0	$6	$3	$64	$32	$78
11	10	$192	$38	0.00%	$0	-$16	$79	$112	$3	$6	$20	$0	$6	$3	$61	$28	$78
12	11	$153	$38	0.00%	$0	-$16	$64	$90	$2	$5	$19	$0	$6	$3	$59	$25	$78
13	12	$115	$38	0.00%	$0	-$16	$48	$67	$2	$4	$18	$0	$6	$3	$56	$22	$78
14	13	$77	$38	0.00%	$0	-$16	$32	$45	$1	$2	$18	$0	$6	$3	$53	$19	$78
15	14	$38	$38	0.00%	$0	-$16	$16	$22	$1	$1	$17	$0	$6	$3	$51	$17	$78
16	15	$0	$38	0.00%	$0	-$16	$0	$0	$0	$0	$16	$0	$6	$3	$48	$15	$78
17	16	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	17	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	18	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	19	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	20	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	21	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	22	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	23	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	24	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	25	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	26	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	27	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	28	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	29	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	30	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	Total	$0	$575		$575	$0		$0	$78	$162	$115	$6	$94	$45	$1,074	$662	$1,164

NPV	$662	NPV Check	$662
Levelized Payment	$78	Fixed Charge Rate	13.50%

Calculations:

1 - Column (B): Beg. Bal. = New Install Cost; Reduced annually by Column (C); Year End Balances
2- Column (C) = Beg. Bal Column (B) / Assumed Book Life Investment (yrs)
3 - Column (D) = MACRS Depreciation
4 - Column (E) = Column (D) X Beg. Bal. Column (B)
5 - Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
6 - Column (G) = Column (F) + Column (G) of prior period
7 - Column (H) = Column (B) - Column (G)
8 - Column (I) = Column (H) X Assumed Debt Ratio X Assumed Debt Cost
9 - Column (J) = Column (H) X Assumed Equity Ratio X Assumed Equity Cost
10 - Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
11 - Column (L) = New Install Cost Beg. Bal. X Taxes Other Than Income Allocation Factor
12 - Column (M) = New Install Cost Beg. Bal. X A&G Allocation Factor
13 - Column (N) = New Install Cost Beg. Bal. X Customer Expense Allocation Factor
14 - Column (O) = New Install Cost Beg. Bal. X Distribution O&M Allocation Factor
15 - Column (P) = Column (C) + Column (F) + Column (I) + Column (J) + Column (K) + Column (L) + Column (M) + Column (N) + Column (O)
16 - Column (Q) = Column (P) / (1+ Rate of Return) ^ Column (A)
17 - Fixed Charge Rate = Levelized Payment / Beg. Bal. Column (B)

Metropolitan Edison Company
Levelized Payment Calculation

Cobra Head / 7000L / Group Install

Line No.	Year	Undepreciated Balance	Book Depr. Expense	Tax Depreciation Rate	Tax Depreciation Expense	DIT Expense	ADIT	Rate Base Balance	Interest Expense	Equity Return	CIT Expense	Property Taxes	Customer Expense	Distribution O&M	Total Fixed Chgs	Present Value	Levelized Payment
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(N)	(O)	(P)	(Q)	(R)
1	0	$720															
2	1	$672	$48	14.29%	$103	$23	$23	$649	$17	$35	$2	$0	$8	$4	$137	$127	$97
3	2	$624	$48	24.49%	$176	$53	$76	$548	$14	$30	-$32	$0	$8	$4	$125	$107	$97
4	3	$576	$48	17.49%	$126	$32	$108	$468	$12	$25	-$14	$0	$8	$4	$116	$92	$97
5	4	$528	$48	12.49%	$90	$17	$126	$402	$10	$22	-$2	$0	$8	$4	$108	$79	$97
6	5	$480	$48	8.93%	$64	$7	$132	$347	$9	$19	$7	$0	$8	$4	$101	$69	$97
7	6	$432	$48	8.92%	$64	$7	$139	$293	$8	$16	$5	$0	$8	$4	$95	$60	$97
8	7	$384	$48	8.93%	$64	$7	$146	$238	$6	$13	$2	$0	$8	$4	$88	$51	$97
9	8	$336	$48	4.46%	$32	-$7	$139	$197	$5	$11	$14	$0	$8	$4	$83	$45	$97
10	9	$288	$48	0.00%	$0	-$20	$119	$168	$4	$9	$26	$0	$8	$4	$80	$40	$97
11	10	$240	$48	0.00%	$0	-$20	$100	$140	$4	$8	$25	$0	$8	$4	$77	$35	$97
12	11	$192	$48	0.00%	$0	-$20	$80	$112	$3	$6	$24	$0	$8	$4	$73	$31	$97
13	12	$144	$48	0.00%	$0	-$20	$60	$84	$2	$5	$23	$0	$8	$4	$70	$28	$97
14	13	$96	$48	0.00%	$0	-$20	$40	$56	$1	$3	$22	$0	$8	$4	$67	$24	$97
15	14	$48	$48	0.00%	$0	-$20	$20	$28	$1	$2	$21	$0	$8	$4	$63	$21	$97
16	15	$0	$48	0.00%	$0	-$20	$0	$0	$0	$0	$20	$0	$8	$4	$60	$19	$97
17	16	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	17	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	18	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	19	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	20	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	21	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	22	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	23	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	24	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	25	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	26	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	27	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	28	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	29	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	30	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	Total	$0	$720		$720	$0		$0	$97	$203	$144	$7	$118	$56	$1,345	$829	$1,458

NPV	$829	NPV Check	$829
Levelized Payment	$97	Fixed Charge Rate	13.50%

Calculations:

1 - Column (B): Beg. Bal. = New Install Cost; Reduced annually by Column (C); Year End Balances
2- Column (C) = Beg. Bal Column (B) / Assumed Book Life Investment (yrs)
3 - Column (D) = MACRS Depreciation
4 - Column (E) = Column (D) X Beg. Bal. Column (B)
5 - Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
6 - Column (G) = Column (F) + Column (G) of prior period
7 - Column (H) = Column (B) - Column (G)
8 - Column (I) = Column (H) X Assumed Debt Ratio X Assumed Debt Cost
9 - Column (J) = Column (H) X Assumed Equity Ratio X Assumed Equity Cost
10 - Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
11 - Column (L) = New Install Cost Beg. Bal. X Taxes Other Than Income Allocation Factor
12 - Column (M) = New Install Cost Beg. Bal. X A&G Allocation Factor
13 - Column (N) = New Install Cost Beg. Bal. X Customer Expense Allocation Factor
14 - Column (O) = New Install Cost Beg. Bal. X Distribution O&M Allocation Factor
15 - Column (P) = Column (C) + Column (F) + Column (I) + Column (J) + Column (K) + Column (L) + Column (M) + Column (N) + Column (O)
16 - Column (Q) = Column (P) / (1+ Rate of Return) ^ Column (A)
17 - Fixed Charge Rate = Levelized Payment / Beg. Bal. Column (B)

Metropolitan Edison Company
Levelized Payment Calculation

Cobra Head / 11500L / Group Install

Line No.	Year (A)	Undepreciated Balance (B)	Book Depr. Expense (C)	Tax Depreciation Rate (D)	Tax Depreciation Expense (E)	DIT Expense (F)	ADIT (G)	Rate Base Balance (H)	Interest Expense (I)	Equity Return (J)	CIT Expense (K)	Property Taxes (L)	Customer Expense (N)	Distribution O&M (O)	Total Fixed Chgs (P)	Present Value (Q)	Levelized Payment (R)
1	0	$765															
2	1	$714	$51	14.29%	$109	$24	$24	$690	$18	$38	$2	$1	$8	$4	$146	$135	$103
3	2	$663	$51	24.49%	$187	$57	$81	$582	$15	$32	-$34	$1	$8	$4	$133	$114	$103
4	3	$612	$51	17.49%	$134	$34	$115	$497	$13	$27	-$15	$1	$8	$4	$123	$98	$103
5	4	$561	$51	12.49%	$96	$18	$134	$427	$11	$23	-$2	$1	$8	$4	$115	$84	$103
6	5	$510	$51	8.93%	$68	$7	$141	$369	$10	$20	$7	$1	$8	$4	$108	$73	$103
7	6	$459	$51	8.92%	$68	$7	$148	$311	$8	$17	$5	$1	$8	$4	$101	$63	$103
8	7	$408	$51	8.93%	$68	$7	$155	$253	$7	$14	$3	$1	$8	$4	$94	$55	$103
9	8	$357	$51	4.46%	$34	-$7	$148	$209	$5	$11	$15	$1	$8	$4	$89	$48	$103
10	9	$306	$51	0.00%	$0	-$21	$127	$179	$5	$10	$28	$1	$8	$4	$85	$42	$103
11	10	$255	$51	0.00%	$0	-$21	$106	$149	$4	$8	$27	$1	$8	$4	$82	$38	$103
12	11	$204	$51	0.00%	$0	-$21	$85	$119	$3	$7	$26	$1	$8	$4	$78	$33	$103
13	12	$153	$51	0.00%	$0	-$21	$64	$90	$2	$5	$25	$1	$8	$4	$75	$29	$103
14	13	$102	$51	0.00%	$0	-$21	$42	$60	$2	$3	$23	$1	$8	$4	$71	$26	$103
15	14	$51	$51	0.00%	$0	-$21	$21	$30	$1	$2	$22	$1	$8	$4	$67	$23	$103
16	15	$0	$51	0.00%	$0	-$21	$0	$0	$0	$0	$21	$1	$8	$4	$64	$20	$103
17	16	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	17	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	18	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	19	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	20	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	21	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	22	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	23	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	24	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	25	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	26	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	27	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	28	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	29	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	30	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	**Total**	**$0**	**$765**		**$765**	**$0**		**$0**	**$103**	**$216**	**$153**	**$8**	**$125**	**$60**	**$1,430**	**$881**	**$1,550**

NPV	**$881**	**NPV Check**	**$881**
Levelized Payment	**$103**	**Fixed Charge Rate**	**13.50%**

Calculations:

1 - Column (B): Beg. Bal. = New Install Cost; Reduced annually by Column (C); Year End Balances
2- Column (C) = Beg. Bal Column (B) / Assumed Book Life Investment (yrs)
3 - Column (D) = MACRS Depreciation
4 - Column (E) = Column (D) X Beg. Bal. Column (B)
5 - Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
6 - Column (G) = Column (F) + Column (G) of prior period
7 - Column (H) = Column (B) - Column (G)
8 - Column (I) = Column (H) X Assumed Debt Ratio X Assumed Debt Cost
9 - Column (J) = Column (H) X Assumed Equity Ratio X Assumed Equity Cost
10 - Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
11 - Column (L) = New Install Cost Beg. Bal. X Taxes Other Than Income Allocation Factor
12 - Column (M) = New Install Cost Beg. Bal. X A&G Allocation Factor
13 - Column (N) = New Install Cost Beg. Bal. X Customer Expense Allocation Factor
14 - Column (O) = New Install Cost Beg. Bal. X Distribution O&M Allocation Factor
15 - Column (P) = Column (C) + Column (F) + Column (I) + Column (J) + Column (K) + Column (L) + Column (M) + Column (N) + Column (O)
16 - Column (Q) = Column (P) / (1+ Rate of Return) ^ Column (A)
17 - Fixed Charge Rate = Levelized Payment / Beg. Bal. Column (B)

Metropolitan Edison Company
Levelized Payment Calculation

Cobra Head / 24000L / Group Install

Line No.	Year	Undepreciated Balance	Book Depr. Expense	Tax Depreciation Rate	Tax Depreciation Expense	DIT Expense	ADIT	Rate Base Balance	Interest Expense	Equity Return	CIT Expense	Property Taxes	Customer Expense	Distribution O&M	Total Fixed Chgs	Present Value	Levelized Payment
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(N)	(O)	(P)	(Q)	(R)
1	0	$1,183															
2	1	$1,104	$79	14.29%	$169	$37	$37	$1,066	$28	$58	$4	$1	$13	$6	$226	$209	$160
3	2	$1,025	$79	24.49%	$290	$87	$125	$900	$23	$49	-$53	$1	$13	$6	$206	$176	$160
4	3	$946	$79	17.49%	$207	$53	$178	$768	$20	$42	-$23	$1	$13	$6	$190	$151	$160
5	4	$867	$79	12.49%	$148	$29	$207	$661	$17	$36	-$3	$1	$13	$6	$177	$130	$160
6	5	$788	$79	8.93%	$106	$11	$218	$571	$15	$31	$11	$1	$13	$6	$167	$113	$160
7	6	$710	$79	8.92%	$105	$11	$229	$481	$13	$26	$8	$1	$13	$6	$156	$98	$160
8	7	$631	$79	8.93%	$106	$11	$240	$391	$10	$21	$4	$1	$13	$6	$145	$84	$160
9	8	$552	$79	4.46%	$53	-$11	$229	$323	$8	$18	$23	$1	$13	$6	$137	$74	$160
10	9	$473	$79	0.00%	$0	-$33	$196	$277	$7	$15	$43	$1	$13	$6	$132	$66	$160
11	10	$394	$79	0.00%	$0	-$33	$164	$231	$6	$13	$42	$1	$13	$6	$126	$58	$160
12	11	$315	$79	0.00%	$0	-$33	$131	$185	$5	$10	$40	$1	$13	$6	$121	$51	$160
13	12	$237	$79	0.00%	$0	-$33	$98	$138	$4	$8	$38	$1	$13	$6	$115	$45	$160
14	13	$158	$79	0.00%	$0	-$33	$65	$92	$2	$5	$36	$1	$13	$6	$110	$40	$160
15	14	$79	$79	0.00%	$0	-$33	$33	$46	$1	$3	$34	$1	$13	$6	$104	$35	$160
16	15	$0	$79	0.00%	$0	-$33	$0	$0	$0	$0	$33	$1	$13	$6	$99	$31	$160
17	16	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	17	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	18	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	19	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	20	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	21	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	22	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	23	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	24	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	25	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	26	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	27	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	28	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	29	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	30	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	**Total**	**$0**	**$1,183**		**$1,183**	**$0**		**$0**	**$160**	**$334**	**$237**	**$12**	**$193**	**$92**	**$2,210**	**$1,362**	**$2,395**

NPV	**$1,362**	**NPV Check**	**$1,362**
Levelized Payment	**$160**	**Fixed Charge Rate**	**13.50%**

Calculations:

1 - Column (B): Beg. Bal. = New Install Cost; Reduced annually by Column (C); Year End Balances
2- Column (C) = Beg. Bal Column (B) / Assumed Book Life Investment (yrs)
3 - Column (D) = MACRS Depreciation
4 - Column (E) = Column (D) X Beg. Bal. Column (B)
5 - Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
6 - Column (G) = Column (F) + Column (G) of prior period
7 - Column (H) = Column (B) - Column (G)
8 - Column (I) = Column (H) X Assumed Debt Ratio X Assumed Debt Cost
9 - Column (J) = Column (H) X Assumed Equity Ratio X Assumed Equity Cost
10 - Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
11 - Column (L) = New Install Cost Beg. Bal. X Taxes Other Than Income Allocation Factor
12 - Column (M) = New Install Cost Beg. Bal. X A&G Allocation Factor
13 - Column (N) = New Install Cost Beg. Bal. X Customer Expense Allocation Factor
14 - Column (O) = New Install Cost Beg. Bal. X Distribution O&M Allocation Factor
15 - Column (P) = Column (C) + Column (F) + Column (I) + Column (J) + Column (K) + Column (L) + Column (M) + Column (N) + Column (O)
16 - Column (Q) = Column (P) / (1+ Rate of Return) ^ Column (A)
17 - Fixed Charge Rate = Levelized Payment / Beg. Bal. Column (B)

Metropolitan Edison Company
Levelized Payment Calculation

Acorn / 2500L / Group Install

Line No.	Year	Undepreciated Balance	Book Depr. Expense	Tax Depreciation Rate	Tax Depreciation Expense	DIT Expense	ADIT	Rate Base Balance	Interest Expense	Equity Return	CIT Expense	Property Taxes	Customer Expense	Distribution O&M	Total Fixed Chgs	Present Value	Levelized Payment
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(N)	(O)	(P)	(Q)	(R)
1	0	$1,521															
2	1	$1,420	$101	14.29%	$217	$48	$48	$1,372	$36	$75	$5	$1	$17	$8	$290	$269	$205
3	2	$1,318	$101	24.49%	$373	$113	$161	$1,158	$30	$63	-$68	$1	$17	$8	$265	$227	$205
4	3	$1,217	$101	17.49%	$266	$68	$229	$988	$26	$54	-$30	$1	$17	$8	$245	$194	$205
5	4	$1,116	$101	12.49%	$190	$37	$266	$850	$22	$46	-$4	$1	$17	$8	$228	$167	$205
6	5	$1,014	$101	8.93%	$136	$14	$280	$734	$19	$40	$14	$1	$17	$8	$214	$146	$205
7	6	$913	$101	8.92%	$136	$14	$294	$619	$16	$34	$10	$1	$17	$8	$201	$126	$205
8	7	$811	$101	8.93%	$136	$14	$308	$503	$13	$27	$5	$1	$17	$8	$187	$109	$205
9	8	$710	$101	4.46%	$68	-$14	$295	$415	$11	$23	$30	$1	$17	$8	$176	$95	$205
10	9	$608	$101	0.00%	$0	-$42	$252	$356	$9	$19	$56	$1	$17	$8	$169	$84	$205
11	10	$507	$101	0.00%	$0	-$42	$210	$297	$8	$16	$54	$1	$17	$8	$162	$75	$205
12	11	$406	$101	0.00%	$0	-$42	$168	$237	$6	$13	$51	$1	$17	$8	$155	$66	$205
13	12	$304	$101	0.00%	$0	-$42	$126	$178	$5	$10	$49	$1	$17	$8	$148	$58	$205
14	13	$203	$101	0.00%	$0	-$42	$84	$119	$3	$6	$47	$1	$17	$8	$141	$52	$205
15	14	$101	$101	0.00%	$0	-$42	$42	$59	$2	$3	$44	$1	$17	$8	$134	$45	$205
16	15	$0	$101	0.00%	$0	-$42	$0	$0	$0	$0	$42	$1	$17	$8	$127	$40	$205
17	16	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	17	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	18	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	19	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	20	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	21	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	22	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	23	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	24	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	25	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	26	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	27	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	28	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	29	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	30	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	**Total**	**$0**	**$1,521**		**$1,521**	**$0**		**$0**	**$206**	**$429**	**$304**	**$15**	**$249**	**$119**	**$2,843**	**$1,752**	**$3,081**

NPV	**$1,752**	**NPV Check**	**$1,752**
Levelized Payment	**$205**	**Fixed Charge Rate**	**13.50%**

Calculations:

1 - Column (B): Beg. Bal. = New Install Cost; Reduced annually by Column (C); Year End Balances
2- Column (C) = Beg. Bal Column (B) / Assumed Book Life Investment (yrs)
3 - Column (D) = MACRS Depreciation
4 - Column (E) = Column (D) X Beg. Bal. Column (B)
5 - Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
6 - Column (G) = Column (F) + Column (G) of prior period
7 - Column (H) = Column (B) - Column (G)
8 - Column (I) = Column (H) X Assumed Debt Ratio X Assumed Debt Cost
9 - Column (J) = Column (H) X Assumed Equity Ratio X Assumed Equity Cost
10 - Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
11 - Column (L) = New Install Cost Beg. Bal. X Taxes Other Than Income Allocation Factor
12 - Column (M) = New Install Cost Beg. Bal. X A&G Allocation Factor
13 - Column (N) = New Install Cost Beg. Bal. X Customer Expense Allocation Factor
14 - Column (O) = New Install Cost Beg. Bal. X Distribution O&M Allocation Factor
15 - Column (P) = Column (C) + Column (F) + Column (I) + Column (J) + Column (K) + Column (L) + Column (M) + Column (N) + Column (O)
16 - Column (Q) = Column (P) / (1+ Rate of Return) ^ Column (A)
17 - Fixed Charge Rate = Levelized Payment / Beg. Bal. Column (B)

Metropolitan Edison Company
Levelized Payment Calculation

Acorn / 5000L / Group Install

Line No.	Year	Undepreciated Balance	Book Depr. Expense	Tax Depreciation Rate	Tax Depreciation Expense	DIT Expense	ADIT	Rate Base Balance	Interest Expense	Equity Return	CIT Expense	Property Taxes	Customer Expense	Distribution O&M	Total Fixed Chgs	Present Value	Levelized Payment
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(N)	(O)	(P)	(Q)	(R)
1	0	$1,608															
2	1	$1,500	$107	14.29%	$230	$51	$51	$1,450	$38	$79	$5	$1	$18	$8	$307	$284	$217
3	2	$1,393	$107	24.49%	$394	$119	$170	$1,223	$32	$67	-$72	$1	$18	$8	$280	$240	$217
4	3	$1,286	$107	17.49%	$281	$72	$242	$1,044	$27	$57	-$32	$1	$18	$8	$259	$205	$217
5	4	$1,179	$107	12.49%	$201	$39	$281	$898	$23	$49	-$4	$1	$18	$8	$241	$177	$217
6	5	$1,072	$107	8.93%	$144	$15	$296	$776	$20	$42	$15	$1	$18	$8	$227	$154	$217
7	6	$965	$107	8.92%	$143	$15	$311	$654	$17	$36	$10	$1	$18	$8	$212	$133	$217
8	7	$857	$107	8.93%	$144	$15	$326	$531	$14	$29	$5	$1	$18	$8	$197	$115	$217
9	8	$750	$107	4.46%	$72	-$15	$311	$439	$11	$24	$32	$1	$18	$8	$186	$100	$217
10	9	$643	$107	0.00%	$0	-$44	$267	$376	$10	$20	$59	$1	$18	$8	$179	$89	$217
11	10	$536	$107	0.00%	$0	-$44	$222	$314	$8	$17	$57	$1	$18	$8	$171	$79	$217
12	11	$429	$107	0.00%	$0	-$44	$178	$251	$7	$14	$54	$1	$18	$8	$164	$70	$217
13	12	$322	$107	0.00%	$0	-$44	$133	$188	$5	$10	$52	$1	$18	$8	$157	$62	$217
14	13	$214	$107	0.00%	$0	-$44	$89	$125	$3	$7	$49	$1	$18	$8	$149	$54	$217
15	14	$107	$107	0.00%	$0	-$44	$44	$63	$2	$3	$47	$1	$18	$8	$142	$48	$217
16	15	$0	$107	0.00%	$0	-$44	$0	$0	$0	$0	$44	$1	$18	$8	$134	$42	$217
17	16	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	17	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	18	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	19	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	20	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	21	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	22	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	23	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	24	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	25	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	26	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	27	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	28	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	29	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	30	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	**Total**	**$0**	**$1,608**		**$1,608**	**$0**		**$0**	**$217**	**$454**	**$322**	**$16**	**$263**	**$125**	**$3,004**	**$1,852**	**$3,256**

NPV	**$1,852**	**NPV Check**	**$1,852**
Levelized Payment	**$217**	**Fixed Charge Rate**	**13.50%**

Calculations:

1 - Column (B): Beg. Bal. = New Install Cost; Reduced annually by Column (C); Year End Balances
2- Column (C) = Beg. Bal Column (B) / Assumed Book Life Investment (yrs)
3 - Column (D) = MACRS Depreciation
4 - Column (E) = Column (D) X Beg. Bal. Column (B)
5 - Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
6 - Column (G) = Column (F) + Column (G) of prior period
7 - Column (H) = Column (B) - Column (G)
8 - Column (I) = Column (H) X Assumed Debt Ratio X Assumed Debt Cost
9 - Column (J) = Column (H) X Assumed Equity Ratio X Assumed Equity Cost
10 - Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
11 - Column (L) = New Install Cost Beg. Bal. X Taxes Other Than Income Allocation Factor
12 - Column (M) = New Install Cost Beg. Bal. X A&G Allocation Factor
13 - Column (N) = New Install Cost Beg. Bal. X Customer Expense Allocation Factor
14 - Column (O) = New Install Cost Beg. Bal. X Distribution O&M Allocation Factor
15 - Column (P) = Column (C) + Column (F) + Column (I) + Column (J) + Column (K) + Column (L) + Column (M) + Column (N) + Column (O)
16 - Column (Q) = Column (P) / (1+ Rate of Return) ^ Column (A)
17 - Fixed Charge Rate = Levelized Payment / Beg. Bal. Column (B)

Metropolitan Edison Company
Levelized Payment Calculation

Colonial / 2500L / Group Install

Line No.	Year (A)	Undepreciated Balance (B)	Book Depr. Expense (C)	Tax Depreciation Rate (D)	Tax Depreciation Expense (E)	DIT Expense (F)	ADIT (G)	Rate Base Balance (H)	Interest Expense (I)	Equity Return (J)	CIT Expense (K)	Property Taxes (L)	Customer Expense (N)	Distribution O&M (O)	Total Fixed Chgs (P)	Present Value (Q)	Levelized Payment (R)
1	0	$916															
2	1	$855	$61	14.29%	$131	$29	$29	$826	$22	$45	$3	$1	$10	$5	$175	$162	$124
3	2	$794	$61	24.49%	$224	$68	$97	$697	$18	$38	-$41	$1	$10	$5	$160	$137	$124
4	3	$733	$61	17.49%	$160	$41	$138	$595	$16	$32	-$18	$1	$10	$5	$147	$117	$124
5	4	$672	$61	12.49%	$114	$22	$160	$512	$13	$28	-$2	$1	$10	$5	$137	$101	$124
6	5	$611	$61	8.93%	$82	$9	$169	$442	$12	$24	$8	$1	$10	$5	$129	$88	$124
7	6	$550	$61	8.92%	$82	$9	$177	$373	$10	$20	$6	$1	$10	$5	$121	$76	$124
8	7	$489	$61	8.93%	$82	$9	$186	$303	$8	$16	$3	$1	$10	$5	$113	$65	$124
9	8	$428	$61	4.46%	$41	-$8	$177	$250	$7	$14	$18	$1	$10	$5	$106	$57	$124
10	9	$367	$61	0.00%	$0	-$25	$152	$214	$6	$12	$34	$1	$10	$5	$102	$51	$124
11	10	$305	$61	0.00%	$0	-$25	$127	$179	$5	$10	$32	$1	$10	$5	$98	$45	$124
12	11	$244	$61	0.00%	$0	-$25	$101	$143	$4	$8	$31	$1	$10	$5	$93	$40	$124
13	12	$183	$61	0.00%	$0	-$25	$76	$107	$3	$6	$29	$1	$10	$5	$89	$35	$124
14	13	$122	$61	0.00%	$0	-$25	$51	$71	$2	$4	$28	$1	$10	$5	$85	$31	$124
15	14	$61	$61	0.00%	$0	-$25	$25	$36	$1	$2	$27	$1	$10	$5	$81	$27	$124
16	15	$0	$61	0.00%	$0	-$25	$0	$0	$0	$0	$25	$1	$10	$5	$76	$24	$124
17	16	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	17	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	18	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	19	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	20	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	21	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	22	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	23	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	24	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	25	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	26	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	27	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	28	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	29	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	30	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	**Total**	**$0**	**$916**		**$916**	**$0**		**$0**	**$124**	**$259**	**$183**	**$9**	**$150**	**$72**	**$1,713**	**$1,056**	**$1,856**

NPV	**$1,056**	**NPV Check**	**$1,056**
Levelized Payment	**$124**	**Fixed Charge Rate**	**13.50%**

Calculations:

1 - Column (B): Beg. Bal. = New Install Cost; Reduced annually by Column (C); Year End Balances
2- Column (C) = Beg. Bal Column (B) / Assumed Book Life Investment (yrs)
3 - Column (D) = MACRS Depreciation
4 - Column (E) = Column (D) X Beg. Bal. Column (B)
5 - Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
6 - Column (G) = Column (F) + Column (G) of prior period
7 - Column (H) = Column (B) - Column (G)
8 - Column (I) = Column (H) X Assumed Debt Ratio X Assumed Debt Cost
9 - Column (J) = Column (H) X Assumed Equity Ratio X Assumed Equity Cost
10 - Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
11 - Column (L) = New Install Cost Beg. Bal. X Taxes Other Than Income Allocation Factor
12 - Column (M) = New Install Cost Beg. Bal. X A&G Allocation Factor
13 - Column (N) = New Install Cost Beg. Bal. X Customer Expense Allocation Factor
14 - Column (O) = New Install Cost Beg. Bal. X Distribution O&M Allocation Factor
15 - Column (P) = Column (C) + Column (F) + Column (I) + Column (J) + Column (K) + Column (L) + Column (M) + Column (N) + Column (O)
16 - Column (Q) = Column (P) / (1+ Rate of Return) ^ Column (A)
17 - Fixed Charge Rate = Levelized Payment / Beg. Bal. Column (B)

Metropolitan Edison Company
Levelized Payment Calculation

Colonial / 5000L / Group Install

Line No.	Year (A)	Undepreciated Balance (B)	Book Depr. Expense (C)	Tax Depreciation Rate (D)	Tax Depreciation Expense (E)	DIT Expense (F)	ADIT (G)	Rate Base Balance (H)	Interest Expense (I)	Equity Return (J)	CIT Expense (K)	Property Taxes (L)	Customer Expense (N)	Distribution O&M (O)	Total Fixed Chgs (P)	Present Value (Q)	Levelized Payment (R)
1	0	$1,008															
2	1	$940	$67	14.29%	$144	$32	$32	$909	$24	$49	$3	$1	$11	$5	$192	$178	$136
3	2	$873	$67	24.49%	$247	$75	$106	$767	$20	$42	-$45	$1	$11	$5	$175	$150	$136
4	3	$806	$67	17.49%	$176	$45	$152	$654	$17	$36	-$20	$1	$11	$5	$162	$128	$136
5	4	$739	$67	12.49%	$126	$24	$176	$563	$15	$31	-$3	$1	$11	$5	$151	$111	$136
6	5	$672	$67	8.93%	$90	$9	$185	$486	$13	$26	$9	$1	$11	$5	$142	$96	$136
7	6	$605	$67	8.92%	$90	$9	$195	$410	$11	$22	$6	$1	$11	$5	$133	$83	$136
8	7	$537	$67	8.93%	$90	$9	$204	$333	$9	$18	$3	$1	$11	$5	$124	$72	$136
9	8	$470	$67	4.46%	$45	-$9	$195	$275	$7	$15	$20	$1	$11	$5	$117	$63	$136
10	9	$403	$67	0.00%	$0	-$28	$167	$236	$6	$13	$37	$1	$11	$5	$112	$56	$136
11	10	$336	$67	0.00%	$0	-$28	$139	$197	$5	$11	$35	$1	$11	$5	$107	$50	$136
12	11	$269	$67	0.00%	$0	-$28	$111	$157	$4	$9	$34	$1	$11	$5	$103	$44	$136
13	12	$202	$67	0.00%	$0	-$28	$84	$118	$3	$6	$32	$1	$11	$5	$98	$39	$136
14	13	$134	$67	0.00%	$0	-$28	$56	$79	$2	$4	$31	$1	$11	$5	$93	$34	$136
15	14	$67	$67	0.00%	$0	-$28	$28	$39	$1	$2	$29	$1	$11	$5	$89	$30	$136
16	15	$0	$67	0.00%	$0	-$28	$0	$0	$0	$0	$28	$1	$11	$5	$84	$26	$136
17	16	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	17	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	18	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	19	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	20	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	21	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	22	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	23	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	24	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	25	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	26	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	27	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	28	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	29	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	30	$0	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	**Total**	**$0**	**$1,008**		**$1,008**	**$0**		**$0**	**$136**	**$284**	**$202**	**$10**	**$165**	**$79**	**$1,883**	**$1,161**	**$2,041**

NPV	**$1,161**	**NPV Check**	**$1,161**
Levelized Payment	**$136**	**Fixed Charge Rate**	**13.50%**

Calculations:

1 - Column (B): Beg. Bal. = New Install Cost; Reduced annually by Column (C); Year End Balances
2- Column (C) = Beg. Bal Column (B) / Assumed Book Life Investment (yrs)
3 - Column (D) = MACRS Depreciation
4 - Column (E) = Column (D) X Beg. Bal. Column (B)
5 - Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
6 - Column (G) = Column (F) + Column (G) of prior period
7 - Column (H) = Column (B) - Column (G)
8 - Column (I) = Column (H) X Assumed Debt Ratio X Assumed Debt Cost
9 - Column (J) = Column (H) X Assumed Equity Ratio X Assumed Equity Cost
10 - Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
11 - Column (L) = New Install Cost Beg. Bal. X Taxes Other Than Income Allocation Factor
12 - Column (M) = New Install Cost Beg. Bal. X A&G Allocation Factor
13 - Column (N) = New Install Cost Beg. Bal. X Customer Expense Allocation Factor
14 - Column (O) = New Install Cost Beg. Bal. X Distribution O&M Allocation Factor
15 - Column (P) = Column (C) + Column (F) + Column (I) + Column (J) + Column (K) + Column (L) + Column (M) + Column (N) + Column (O)
16 - Column (Q) = Column (P) / (1+ Rate of Return) ^ Column (A)
17 - Fixed Charge Rate = Levelized Payment / Beg. Bal. Column (B)

Metropolitan Edison Company
Installation Costs

Line No.	Light Type	Monthly kWh	Lumens	Wattage	Installation Cost (12 Lights)
1	Cobra Head	18	4,000	50	$5,480.53
2	Cobra Head	32	7,000	90	$6,865.28
3	Cobra Head	46	11,500	130	$7,298.01
4	Cobra Head	91	24,000	260	$11,279.16
5	Acorn	18	2,500	50	$14,508.80
6	Acorn	32	5,000	90	$15,332.43
7	Colonial	18	2,500	50	$8,740.46
8	Colonial	32	5,000	90	$9,610.25

Metropolitan Edison Company
Distribution Costs

Line No.	Other Distribution Plant Allocated to Streetlighting			
1	Total Distribution Plant to Streetlighting	$	26,898,000	*Met-Ed Exhibit HES-1*
2	Total Directly Assigned Plant to Streetlighting	$	22,915,000	*Met-Ed Exhibit HES-1*
3	Total Other Distribution Plant to Streetlighting	$	3,983,000	*Line 1 - Line 2*
4	**Other Distribution Plant Factor**		**17.38%**	*Line 3 / Line 2*
	Other Distribution O&M Allocated to Streetlighting			
5	Total Distribution O&M to Streetlighting	$	400,000	*Met-Ed Exhibit HES-1*
6	Total Directly Assigned O&M to Streetlighting	$	250,000	*Met-Ed Exhibit HES-1*
7	Other Distribution O&M to Streetlighting	$	150,000	*Line 5 - Line 6*
8	**Other Distribution O&M Factor**		**0.65%**	*Line 7 / Line 2*

Metropolitan Edison Company
General Property

Line No.	General Property Allocated to Streetlighting	ME 2013 FERC Form 1	
1	Gross Investment in Streetlighting	$ 12,229,688	*FF1, 207.73.g*
2	Total Investment in Plant	$ 2,705,225,121	*FF1, 207.104.g*
3	Total General Plant	$ (210,468,340)	*FF1, 207.99.g*
4	Total Investment in Plant Less General Plant	$ 2,494,756,781	*Line 2 + Line 3*
5	Streetlighting % of Total Plant (Less General)	0.49%	*Line 1 / Line 4*
6	General Plant Allocated to Streetlighting	$ 1,031,749	*Line 3 * Line 5*
7	**General Plant Factor**	**8.44%**	*Line 6 / Line 1*

Metropolitan Edison Company
Customer Expenses

Customer Accounts Expense

Line No.	Account	Description	ME 2013 FERC Form 1	Allocation	Streetlighting Related	
1	901	Supervision	$ 5,287	0.11%	$ 6	*FF1, 322.159.b*
2	902	Meter Reading	$ 4,131,264	0.00%	$ 0	*FF1, 322.160.b*
3	903	Customer Records and Collection Expenses	$ 6,257,008	0.11%	$ 6,656	*FF1, 322.161.b*
4	904	Uncollectible Accounts	$ 14,333,240	0.81%	$ 116,258	*FF1, 322.162.b*
5	905	Miscellaneous Customer Accounts Expenses	$ 238,152	0.11%	$ 253	*FF1, 322.163.b*
6		Total	$ 24,964,951		$ 123,173	*Sum: Lines 1-5*

Customer Service and Information Expenses

	Account	Description	ME 2013 FERC Form 1	Allocation	Streetlighting Related	
7	907	Supervision	$ 204,598	0.11%	$ 218	*FF1, 323.167.b*
8	908	Customer Assistance Expense	$ 36,521,122	0.11%	$ 38,853	*FF1, 323.168.b*
9	909	Informational and Instructional Expenses	$ 460	0.11%	$ 0	*FF1, 323.169.b*
10	910	Misc. Customer Service and Information Exp	$ 5,174,025	0.11%	$ 5,504	*FF1, 323.170.b*
11		Total	$ 41,900,205		$ 44,575	*Sum: Lines 7-10*
12	373	Gross Investment in Streetlighting			$ 12,229,688	*FF1, 207.73.g*
13		**Customer Expense Allocation Factor**			**1.37%**	**(Line 6 + Line 11) / Line 12**

Memo:

	Streetlighting Related Customer Accounts Expense	ME 2013 FERC Form 1	
14	Total Revenues	$ 752,022,790	*FF1, 304.43.c*
15	Total Street Lighting Revenues	$ 6,099,704	*FF1, 304.32.c*
16	% of Street Lighting to Total	0.81%	*Line 15 / Line 14*
	Customer Count		
17	Total number of customers	554,596	*FF1, 304.43.d*
18	Estimated number of streetlighting customers	590	*FF1, 304.32.d*
19	% of Total	0.11%	*Line 18 / Line 17*

Metropolitan Edison Company
Property Taxes

Line No.	Description		ME 2013 FERC Form 1	
1	Local Real Estate	$	128,166	FF1, 263.30.i
2	PURTA	$	1,930,000	FF1, 263.1.2.i
3	Total	**$**	**2,058,166**	Line 1 + Line 2
	Property Taxes Allocated to Income			
4	Streetlighting % of Total Plant (Less General)		0.49%	*Page 12, Line 5*
5	Property Taxes Allocated to Streetlighting	$	10,089	*Line 3 * Line 5*
6	**Property Taxes Factor**		**0.08%**	*Line 5 / Page 12, Line 1*

Metropolitan Edison Company
Capital Recovery Factors

Line No.	Rate of Return (RoR) 2014 Capital Structure	Percent	Cost Rate	Weighted Cost Rate
1	Long Term Debt	50.04%	5.210%	2.607%
2	Common Equity	49.96%	10.900%	5.446%
3	Total	100.00%		8.053%
	Depreciation			
4	Depreciable Years (n)	15		
5	SLD = 1 / n	6.67%		
6	Tax Life of Investment (yrs)	7		
	Taxes	2014		
7	Federal Income Tax Rate	35.00%		
8	State Income Tax Rate	9.99%		
9	Effective Tax Rate	41.493500%		

Metropolitan Edison Company
Asset Life - Tax Books

	MACRS Half-Year Convention					
	3	5	7	10	15	20
1	33.33%	20.00%	14.29%	10.00%	5.00%	3.750%
2	44.45%	32.00%	24.49%	18.00%	9.50%	7.219%
3	14.81%	19.20%	17.49%	14.40%	8.55%	6.677%
4	7.41%	11.52%	12.49%	11.52%	7.70%	6.177%
5	0.00%	11.52%	8.93%	9.22%	6.93%	5.713%
6	0.00%	5.76%	8.92%	7.37%	6.23%	5.285%
7	0.00%	0.00%	8.93%	6.55%	5.90%	4.888%
8	0.00%	0.00%	4.46%	6.55%	5.90%	4.522%
9	0.00%	0.00%	0.00%	6.56%	5.91%	4.462%
10	0.00%	0.00%	0.00%	6.55%	5.90%	4.461%
11	0.00%	0.00%	0.00%	3.28%	5.91%	4.462%
12	0.00%	0.00%	0.00%	0.00%	5.90%	4.461%
13	0.00%	0.00%	0.00%	0.00%	5.91%	4.462%
14	0.00%	0.00%	0.00%	0.00%	5.90%	4.461%
15	0.00%	0.00%	0.00%	0.00%	5.91%	4.462%
16	0.00%	0.00%	0.00%	0.00%	2.95%	4.461%
17	0.00%	0.00%	0.00%	0.00%	0.00%	4.462%
18	0.00%	0.00%	0.00%	0.00%	0.00%	4.461%
19	0.00%	0.00%	0.00%	0.00%	0.00%	4.462%
20	0.00%	0.00%	0.00%	0.00%	0.00%	4.461%
21	0.00%	0.00%	0.00%	0.00%	0.00%	2.231%
22	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
23	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
24	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
25	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
26	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
27	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
28	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
29	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
30	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
31	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
32	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
33	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
34	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
35	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
36	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
37	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
38	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
39	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
40	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%
41	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%

Met-Ed/Penelec/Penn Power/West Penn
LED Street Lighting Monthly Fixture Charge

	Fixture Information			Monthly Unit Cost			
	Type	Lumens	Wattage	ME	PN	PP	WPP
1	Cobra Head	4000	50	$ 6.87	$ 5.89	$ 5.25	$ 5.52
2		7000	90	$ 8.61	$ 7.41	$ 6.59	$ 6.94
3		11500	130	$ 9.15	$ 7.88	$ 7.01	$ 7.38
4		24000	260	$ 14.14	$ 12.24	$ 10.84	$ 11.44
5	Acorn	2500	50	$ 18.19	$ 15.78	$ 13.95	$ 14.73
6		5000	90	$ 19.22	$ 16.68	$ 14.75	$ 15.57
7	Colonial	2500	50	$ 10.96	$ 9.46	$ 8.40	$ 8.85
8		5000	90	$ 12.05	$ 10.41	$ 9.23	$ 9.74

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2014-2428745

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. R-2014-242743

PENNSYLVANIA POWER COMPANY
DOCKET NO. R-2014-242744

WEST PENN POWER COMPANY
DOCKET NO. R-2014-2428742

Direct Testimony
of
Richard A. D'Angelo

List of Topics Addressed

Accounting and Financial Data
Budgets
Ratemaking Adjustments to Budgeted Test Year Data
Regulatory Treatment of Storm Damage Costs
Accelerated Customer Switching Costs
Other Filing Requirements

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DIRECT TESTIMONY
OF
RICHARD A. D'ANGELO

I. INTRODUCTION AND PURPOSE

Q. Please state your name and business address.

A. My name is Richard A. D'Angelo. My business address is 2800 Pottsville Pike Reading, Pennsylvania 19605.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company as Manager – Rates and Regulatory Affairs – Pennsylvania.

Q. Please describe your responsibilities as Manager – Rates and Regulatory Affairs – Pennsylvania.

A. Generally, the Rates and Regulatory Affairs Department provides regulatory support for Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power") and West Penn Power Company ("West Penn") (each of which may be referred to as "Company" or collectively as the "Companies"). I am responsible to the Director of Rates & Regulatory Affairs for the development, coordination, preparation and presentation of the Companies' accounting and financial data in all their rate-related matters before the Pennsylvania Public Utility Commission ("PUC" or "Commission") and the Federal Energy Regulatory Commission ("FERC"), as well as the preparation of statements and reports addressing, among other things,

energy costs, non-utility generation ("NUG") costs, quarterly earnings, and other financial matters. Also, I am responsible for the administration of the Companies' retail and wholesale tariffs, the development of retail electric rates, and the promulgation of rules and regulations ensuring uniform tariff administration and interpretation.

Q. What is your educational and professional background?

A. I obtained a Masters Degree in Business Administration from Pace University in 1976. I am also a graduate of Brooklyn College where I received a Bachelor of Science degree with a major in Economics. I have over thirty-eight years of experience with FirstEnergy Service Company and GPU Energy. My work experience is more fully described in Appendix A.

Q. Have you previously testified in regulatory proceedings?

A. Yes. As set forth in Appendix A, I have previously testified before the Commission, as well as the New Jersey Board of Public Utilities, the New York State Public Service Commission and, at the federal level, before FERC.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying in this proceeding on behalf of Met-Ed, Penelec, Penn Power and West Penn. My testimony equally applies to all of the Companies, unless otherwise stated.

Q. Please describe the purpose of your direct testimony.

A. The general purpose of my testimony is to describe and support: (i) various accounting, rate case, and other financial data that are being submitted in response to the filing requirements for an electric utility base rate case proceeding; (ii) the budget level of capital and operation and maintenance ("O&M") expenses; (iii) ratemaking adjustments to the budgeted test year rate base and operating income statement; (iv) the rolling into base rates of smart meter costs; (v) the removal of universal service costs for West Penn and their proposed recovery through a new reconciliation rider; (vi) the proposed treatment of deferred storm damage expenses and recovery of ongoing storm damage costs; and (viii) capital and O&M costs associated with the Commission's directive that electric distribution companies ("EDCs") accelerate customer switching of electric generation suppliers ("EGSs").

Q. Have you prepared exhibits to accompany your testimony?

A. Yes. Met-Ed Exhibits RAD-1 through RAD-64, Penelec Exhibits RAD-1 through RAD-64, Penn Power Exhibits RAD-1 through RAD-64 and West Penn Exhibits RAD-1 through RAD-64 (collectively, Exhibits RAD-1 through RAD-64) were prepared by me or under my supervision. Of these, my testimony will focus primarily on Exhibit RAD-1, which sets forth each Company's proposed rate base at April 30, 2016, i.e., the end of the fully projected future test year ("FPFTY") being utilized in this proceeding, and RAD-2, which provides a detailed income statement and support for certain normalization and annualization adjustments to

the budgeted FPFTY data. The remaining exhibits, for the most part, comprise responses to those Commission base rate filing requirements for which I am responsible.

Q. Please identify those witnesses whose testimony relates to and supports your testimony and exhibits.

A. Kimberlie L. Bortz (Met-Ed/Penelec/Penn Power/West Penn Statement No. 3) describes and supports the Storm Damage Recovery Riders proposed for all four Companies and the Universal Service Cost ("USC") Rider proposed for West Penn.

Kevin M. Siedt (Met-Ed/Penelec/Penn Power/West Penn Statement No. 4) supports the pro forma levels of energy sales and normalized revenues utilized to determine the Companies' need for rate relief. Mr. Siedt also details the Companies' proposed rate design and various rider modifications.

Hillary E. Stewart (Met-Ed/Penelec/Penn Power/West Penn Statement No. 5) explains the cost of service study she performed along with how various cost of service components (e.g., rate base, expenses) attributable to FERC jurisdictional service were identified and removed from the determination of the Companies' distribution revenue requirement.

Patricia M. Larkin (Met-Ed/Penelec/Penn Power/West Penn Statement No. 6) supports the Companies' cash working capital requirements.

Laura W. Gifford (Met-Ed/Penelec/Penn Power/West Penn Statement No. 7) describes and supports the normalization of uncollectible accounts expense, the unbundling of West Penn's generation uncollectible accounts expense, and the proposed roll-in to base rates of smart meter capital and O&M expenses.

Michael J. Vilbert (Met-Ed/Penelec/Penn Power/West Penn Statement No. 9) develops a range of the cost of equity capital to be utilized in the calculation of the Companies' overall rates of return.

Steven R. Staub (Met-Ed/Penelec/Penn Power/West Penn Statement No. 10) presents the Companies' proposed capital structure ratios and weighted average costs of long-term debt. In addition, he supports the Companies' requested return on common equity of 10.9%.

II. ACCOUNTING AND FINANCIAL DATA

Q. Do the Companies adhere to a system of accounts prescribed by the Commission?

A. Yes. The Companies' accounting records are maintained in accordance with the Commission's regulations at 52 Pa. Code Sec. § 57.41 *et seq.* and in conformity with the Uniform System of Accounts prescribed by the FERC and adopted by the Commission.

Q. Are the Companies' accounting records audited?

A. Yes. The Companies' financial records are audited at least annually by an independent certified public accounting firm. In addition, the FERC conducts

periodic compliance audits to confirm that the Companies are keeping their accounts in conformity with the Uniform System of Accounts. In addition to conducting its own audits, the staff of the PUC reviews the findings of FERC's audits. Other independent agencies also have the authority to audit the Companies' records on a recurring basis, including the Internal Revenue Service ("IRS") and the Securities and Exchange Commission ("SEC"). In addition, the PUC audit staff and the Pennsylvania Department of Revenue staff perform annual audits of the cost recovery rider mechanisms and sales and use tax filings.

Q. Have original cost determinations been made of the Companies' utility plant?

A. Yes. For Met-Ed, an original cost determination was made as of December 31, 1944, for which approval orders were issued by the PUC on December 11, 1945 at EOC Docket No. 27 and for Edison Light and Power Company (which was subsequently merged with Met-Ed) on November 12, 1946 at Docket No. 11. In 1948, the Company filed with the Commission a basic plan for maintaining its continuing property records. The PUC accepted and approved that plan on April 19, 1948.

For Penelec, an original cost determination was made as of December 31, 1943, by Commission Order dated January 15, 1945 at Docket Nos. EOC 32, MGOC 17, EOC 7, EOC 13, EOC 14, EOC 22 and EOC 44. Original cost determinations were also made for the following major companies which were later merged into Penelec: Pennsylvania Edison Company at Docket Nos. EOC 31 and MGOC 16

by Order dated November 1, 1946 approving balances at July 2, 1946; Northern Pennsylvania Power Company at Docket No. EOC 29 by Order dated January 2, 1946 approving balances at December 31, 1944; and Home Electric Company at Docket No. EOC 21 by Order dated August 20, 1945 approving balances at January 1, 1938.

For Penn Power, an original cost determination was approved by the Commission in the mid-1940's. A subsequent original cost determination was made as part of the Commission's April 6, 1984 Order in Penn Power's base rate proceeding at Docket No. R-832409 (58 PaPUC 305, 60 PUR 4th 593). In that case, the Commission, at the recommendation of the Office of Trial Staff, directed Penn Power to develop its revenue requirement on the basis of its book reserve for depreciation and to convert to the average remaining life method of depreciation and, in so doing, established depreciated original cost plant values to be utilized henceforth.

For West Penn, an original cost determination was made as of December 31, 1943, by Order of this Commission dated July 10, 1945 at Docket No. 50.

The Companies have, since the dates noted above, maintained their continuing property records in accordance with the approved plans.

III. BUDGETS

Q. Mr. D'Angelo, are you familiar with the process by which Met-Ed, Penelec, Penn Power and West Penn budget future capital expenditures, revenues and operating expenses?

A. Yes, I am. In general, the Companies' budgeting process involves: (1) the establishment of documented and well-supported goals, objectives and guidelines; (2) intensive reviews and refinements by all levels of management and functional staffs; and (3) careful scrutiny and ultimate approval by appropriate senior management.

Q. How were those budgets utilized to develop the Companies' claimed revenue requirements in these proceedings?

A. They provided the starting point for determining the Companies' claimed rate base at April 30, 2016 and operating income for the twelve months ending that date. Specifically, I consolidated budgeted monthly data for the months of May through December from the 2015 forecast and the months of January through April from the 2016 forecast to develop the "Per Budget" amounts set forth in Column 1 of Exhibits RAD-1 and RAD-2.

Q. Did you update any of the budgeted data for purposes of these rate filings?

A. Yes. Since the completion of the capital budget, certain revisions were made to the forecasted capital structures of the Companies and those changes have been reflected by Mr. Staub in his testimony and exhibits. Also, the Companies made certain changes to the test year for: (1) updated tax depreciation (Exhibits RAD-

33); (2) the provision for deferred income taxes (Exhibits RAD-41); and (3) accumulated deferred income taxes (Exhibits RAD-35).

Q. What opinion, if any, do you have as to the budgeted levels of capital and expense?

A. In my opinion, the budgeted levels of capital and expense are reasonable estimates of what Met-Ed, Penelec, Penn Power and West Penn can expect to experience during the FPFTY prior to recognition of the appropriate ratemaking adjustments reflected in Exhibits RAD-1 and RAD-2.

IV. RATEMAKING ADJUSTMENTS TO BUDGETED TEST YEAR DATA

A. Rate Base at April 30, 2016 (Exhibits RAD-1)

Q. Please generally describe Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-1.

A. These exhibits, which are essentially identical in format, set forth, for each Company, its proposed overall distribution rate base and smart meter rate base at April 30, 2016. Column 1 on page 1 of Exhibits RAD-1 provides budgeted amounts; column 2 adjusts various components; and column 3 reflects the adjusted rate base. The remaining columns on page 1 break the adjusted rate base into separate distribution and smart meter rate base elements.

The adjustments to the budgeted rate base data, along with a detailed explanation of each adjustment, are contained on pages 2 through 11 of Met-Ed, Penelec, and

West Penn, and Penn Power Exhibits RAD-1 and are referenced on page 1 by adjustment number. The adjustments are designed to accomplish the following:

- Remove FERC gross plant and depreciation reserves (Met-Ed, Penelec and West Penn);
- Reflect adjusted depreciation reserves applicable to rate base;
- Eliminate American Transmission Systems, Inc. ("ATSI") plant and depreciation reserves in accordance with the settlement at Docket No. A-110450F0016 (Penn Power);
- Eliminate plant held for future use;
- Reflect the roll-in to base rates of smart meter investment and related depreciation reserves;
- Reflect cash working capital requirements;
- Reflect material and supplies ("M&S") inventories;
- Reflect unamortized deferred storm damage expenses as an addition to rate base (Met-Ed, Penelec and West Penn);
- Reflect the transfer of unrecovered legacy meter investment from plant in service to a regulatory asset account;
- Adjust accumulated deferred income taxes – liberalized depreciation; and
- Adjust operating reserves, net of tax, to remove FERC jurisdictional allocations (Met-Ed, Penelec and West Penn).

Q. Please describe Adjustment No. 1 to Electric Plant in Service.

A. This adjustment eliminates from plant in service accounts: (1) Asset Retirement Costs ("ARC"); (2) FERC Transmission Plant, including allocated portions of Intangible and General Plant, based on the results of a separations study described by Ms. Stewart in Met-Ed/Penelec/Penn Power/West Penn Statement No. 5; (3) legacy meters, as directed by the Commission in the Final Order in the Companies' Smart Meter Deployment Plan at Docket Nos. M-2013-2341990 (Met-Ed), M-2013-2341991 (Penelec), M-2013-2341993 (Penn Power), and M-2013-2341994 (West Penn); and (4) in the case of Penn Power, ATSI plant in accordance with the settlement at Docket No. A-110450F0016.

Q. What are ARC costs?

A. An ARC applies to all legal obligations associated with the retirement of long-lived assets that result from construction under Financial Account Standards Board Statement No. 143 ("FAS-143)." FAS-143 requires that the fair value of a liability for an asset's retirement obligation ("ARO") be recognized in the period in which it is incurred. The associated ARC is capitalized as part of the carrying amount of the long-lived assets. An ARC increases the carrying amount of a long-lived asset when a liability for an ARO is recognized and is depreciated over the life of the asset. The ARC and related depreciation reserve are excluded from rate base, while the associated depreciation expense is excluded from the income statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18, Asset Retirement Obligations.

Q. What is the Companies' position on Plant Held for Future Use?

A. Historically, the Companies claimed in rate base those investments in Plant Held for Future Use that were expected to be utilized within ten years of the test period. The ten-year window reflected the Commission's prior policy of allowing such investments where definitive plans for utilizing the investment within the ten-year period existed. Under current Commission policy, investments in Plant Held for Future Use are excluded from rate base, but allowed to accrue carrying charges provided they satisfy the ten-year test. Adjustment No. 2 is designed to comply with that policy.

Q. Please describe Adjustment No. 3 to Depreciation Reserve - Electric Plant in Service.

A. This adjustment removes from the budgeted depreciation reserve those portions attributable to the plant eliminated in Adjustment No. 1.

Q. What is the purpose of Adjustment No. 4?

A. This adjustment includes the Companies' cash working capital requirements described by Ms. Larkin in Met-Ed/Penelec/Penn Power/West Penn Statement No. 6 and computed by her in Met-Ed, Penelec, Penn Power and West Penn Exhibits PML-1.

Q. Please describe Adjustment No. 5 to M&S inventories.

A. This adjustment includes each Company's allocated portion of the materials and supplies inventory maintained by the FirstEnergy Service Company at March 31,

2014. The historic test year-end balance was used because the Companies do not budget M&S inventories. Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-13 provide a monthly breakdown of M&S inventories for the thirteen months ended March 31, 2014.

Q. What is the purpose of Adjustment No. 6?

A. Adjustment No. 6 includes in claimed rate base certain storm damage costs, the recognition of which has been deferred in accordance with Commission order. The specific costs deferred, and citations to the Commission orders approving their deferral, are provided for Met-Ed, Penelec, and West Penn on page 7 of the exhibits.

Q. Please describe the adjustment for legacy meters.

A. In its March 6, 2014 Order at Docket Nos. M-2013-2341990, et al., approving the Companies' Smart Meter Deployment Plans, the Commission directed that the cost of removing legacy meters (i.e., meters to be replaced by the installation of smart meters) be charged to the regulatory asset account containing the legacy meters and recovered, along with the unrecovered investment in those meters, over the remaining lives of those meters. As noted previously, Adjustment No. 1 transfers the investment in legacy meters that will remain unrecovered as of April 30, 2016, to a regulatory asset account. Adjustment No. 7 adds back to rate base the regulatory asset account, net of accrued depreciation, plus the estimated cost of removal.

Q. Please describe the adjustment of Accumulated Deferred Income Taxes – Liberalized Depreciation.

A. Adjustment No. 8 adjusts the budgeted deferred tax balances for liberalized depreciation, excluding the impact of Statement of Financial Accounting Standards ("SFAS") No. 109 deferrals, to eliminate: (1) deferred income taxes associated with Three Mile Island Unit No. 2 (Met-Ed and Penelec); (2) deferred income taxes associated with other generation (Met-Ed); (3) other excludable items (capital leases); (4) remaining state income tax deferrals including the benefit of those income taxes; and (5) an allocated portion of the remaining federal deferred income taxes associated with FERC Transmission Plant (Met-Ed, Penelec and West Penn).

Q. Please describe the adjustment proposed to operating reserves.

A. Adjustment No. 9 adjusts operating reserves, net of accumulated deferred income taxes, to eliminate an allocated portion associated with FERC transmission operations (Met-Ed, Penelec and West Penn).

Q. After taking into account the foregoing adjustments, what is Met-Ed's claimed distribution rate base?

A. Met-Ed's claimed distribution rate base equals $1,412,965,000, of which $28,109,000 represents the roll-in of smart meter investment.

Q. What is Penelec's claimed distribution rate base?

A. Penelec's claimed distribution rate base equals $1,540,298,000, of which $30,884,000 represents the roll-in of smart meter investment.

Q. What is Penn Power's claimed distribution rate base?

A. Penn Power's claimed distribution rate base equals $358,929,000, of which $24,326,000 represents the roll-in of smart meter investment.

Q. What is West Penn's claimed distribution rate base?

A. West Penn's claimed distribution rate base equals $1,287,287,000, of which $87,918,000 represents the roll-in smart meter investment.

Q. What is contained on page 11 of Exhibits RAD-l?

A. This page sets forth, for each Company, its claimed overall rate of return, including its proposed capital structure ratios, weighted average cost of long-term debt and requested return on common equity. Those findings, which are presented and supported by Mr. Staub and Dr. Vilbert, are summarized below:

1. Met-Ed	Capital Structure Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.0%	5.21%	2.60%
Preferred Stock	0.0%	---	---
Common Equity	50.0%	10.9%	5.45%
	100.0%		8.05%

2. Penelec	Capital Structure Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.1%	5.72%	2.87%
Preferred Stock	---	---	---
Common Equity	49.9%	10.9%	5.44%
	100.0%		8.31%

3. Penn Power	Capital Structure Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	49.9%	6.12%	3.05%
Preferred Stock	---	---	---
Common Equity	50.1%	10.9%	5.46%
	100.0%		8.51%

4. West Penn	Capital Structure Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	49.9%	5.38%	2.68%
Preferred Stock	---	---	---
Common Equity	50.1%	10.9%	5.46%
	100.0%		8.14%

B. Statement of Operating Income For the 12 Months Ending April 30, 2016 (Exhibits RAD-2)

Q. What is contained in Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-2?

A. Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-2 contain the budgeted and pro forma statements of net utility operating income for the FPFTY ending April 30, 2016. The first three pages summarize the budgeted and adjusted results of operations at present and proposed rates; the next five pages break down each Company's revenue requirement by component part (e.g., distribution, smart meter roll-in); and the remaining pages, starting at page 9, document the specific adjustments made to normalize and annualize the budgeted data.

The adjustments are designed to accomplish the following:

- Annualize number of customers, usage and sales at end-of-test-year levels;

- Roll into base rates revenues associated with the State Tax Adjustment Surcharge ("STAS");

- Eliminate non-jurisdictional "Other Operating Revenues," as applicable;

- Annualize payroll and employee benefit costs to reflect anticipated employee levels and benefits;

- Calculate net negative salvage based on a five-year average of actual net salvage, consistent with Commission practice;

- Normalize pension expense to reflect a ten-year average of cash contributions consistent with the approach approved by the Commission in prior proceedings;

- Normalize other post-employment benefits ("OPEBs") to reflect the actual ongoing level of service costs charged to expense consistent with the approach used in the past with Commission approval;

- Normalize depreciation accruals to reflect utility plant in service as of the end of the FPFTY;

- Normalize rate case expenses to reflect a two-year cost recovery period;

- Eliminate non-jurisdictional O&M expenses;

- Normalize O&M expenses associated with serving new customers;

- Eliminate the Universal Service program costs included in West Penn's budget, as such costs will be recovered through West Penn's proposed USC Rider;

- Amortize the unrecovered investment in "legacy" meters being replaced by smart meters over a five-year period;

- Amortize deferred storm damage O&M expenses over a three-year period (Met-Ed, Penelec and West Penn);

- Amortize West Penn's residual merger credit balance to residential customers over two years;

- Remove default service-related uncollectible accounts expense from distribution revenue requirement (West Penn); and

- Adjust taxes other than income including, for Penn Power, rolling the 5.9% Gross Receipts Tax ("GRT") into base rates and all of its applicable cost recovery riders.

Q. What level of GRT has been collected in Penn Power's base rates and its various cost recovery riders?

A. The Commonwealth of Pennsylvania requires Penn Power to pay GRT at the statutory rate of 5.9%. However, Penn Power has been recovering GRT in base rates and cost recovery riders at a 4.4% tax rate and has been recovering the remaining 1.5% of the statutory rate in its STAS.

Q. How does rolling the STAS into base rates impact the Penn Power's various cost recovery riders?

A. Rolling the STAS into Penn Power's base rates requires each of the Company's cost recovery riders to recover fully that rider's GRT revenue requirement. Consequently, each cost recovery rider reflects a shortfall in its GRT recovery, which is made up through an applicable increase in revenue requirements shown on page 2 of Penn Power Exhibit RAD-2. However, the revenue requirements for the Price-To-Compare ("PTC"), USC, Energy Efficiency Conservation Charge ("EE&C-C"), Default Service Support, and Solar Photovoltaic Requirements Charge ("SPVRC") Riders will be updated. Specifically, the actual rates to be imposed under the various cost recovery riders will have their respective GRT component updated as part of the Penn Power compliance filing at the time new base rates approved in this proceeding are implemented. Because the SMT-C

Rider is being rolled into base rates, its revenue requirement will reflect GRT at the statutory 5.9% rate.

Q. Are the Companies seeking to recover any acquisition premium or other transaction costs associated with the FirstEnergy/GPU or FirstEnergy/Allegheny mergers as part of the revenue requirements in this case?

A. No. There is no provision in the budget for, nor has any adjustment been made to include, an amortization of acquisition premiums or other transaction costs associated with either of those mergers.

Q. Please describe Adjustment No. 1.

A. This is an adjustment to base operating revenues to: (1) annualize changes in number of customers; (2) roll-in STAS revenues; (3) normalize the sales and revenue effects of energy efficiency measures implemented or to be implemented under the Companies' Energy Efficiency and Conservation Plans and to reflect behind-the-meter generation; (4) normalize Other Revenue (Met-Ed, Penn Power, and West Penn); (5) street lighting (Penelec); and (6) eliminate unbilled revenue. Parts (1) through (5) of this adjustment are discussed in detail by Mr. Siedt in Met-Ed/Penelec/Penn Power/West Penn Statement No. 4. I address item (6). By way of background, unbilled revenue has been included in the budget projection to reflect revenues for service rendered but not billed as of the end of each accounting period. Items that produce unbilled revenue include such things as increases in rates and increases in the number of customers. In developing pro

forma revenues for ratemaking purposes, separate adjustments are being made to annualize and normalize the revenue effect of such factors. Therefore, to eliminate any duplication of revenue for ratemaking purposes, unbilled revenue must be eliminated, which is done in Adjustment No. 1.

Q. Please describe Adjustment No. 2.

A. This adjustment eliminates revenues projected to be billed under the Companies' STAS Riders. Because all state taxes are included in distribution base rate revenue requirement, no revenues will be billed under the STAS Rider. As the Companies did not forecast any charge under their STAS Rider, the adjustment is zero.

Q. Please describe Adjustment No. 3.

A. This adjustment eliminates non-jurisdictional FERC transmission revenues from electric revenues projected for the FPFTY.

Q. What is the purpose of Adjustment No. 4 to Distribution Expense?

A. This adjustment: (1) normalizes each of the Companies' and FirstEnergy Service Company's payroll expense to reflect year-end wage and employee levels; (2) eliminates non-jurisdictional transmission expenses; and (3) excludes the transmission portion of the amortization of gains or losses to reacquire debt, where applicable, based on the results of the separations study described by Ms. Stewart in Met-Ed/Penelec/Penn Power/West Penn Statement No. 5.

Supporting Schedule No. 1 develops the payroll expense to reflect year end wage and employee levels for both Company and FirstEnergy Service Company employees. The O&M payroll expense for each Company and FirstEnergy Service Company is then allocated to individual Price to Compare, Transmission, Distribution, Customer Accounts, Customer Service and Administrative and General components. These amounts are later utilized in subsequent adjustments.

Q. Please describe Adjustment No. 5 to Customer Accounts Expense.

A. Customer Accounts expense is adjusted to reflect year end wage and employee levels for each Company and FirstEnergy Service Company personnel (developed in Adjustment No. 4), increased costs associated with added new customers and interest on customer deposits.

Supporting Schedule No. 1 develops the Other O&M expenses associated with serving new customers reflected in Adjustment No. 1. The Commission has previously approved an adjustment to customer accounts expense in recognition of this increased cost. This cost is estimated by determining the ratio of non-payroll customer account expense to distribution revenues from customers and applying this ratio to the additional revenue received from increased customers.

Supporting Schedule No. 1 also captures the cost of interest the Companies are required to pay on customer deposits since the customer deposits are deducted from rate base.

Q. What is the purpose of Adjustment No. 6 to Customer Service and Informational Expense?

A. Customer Service and Informational Expense is adjusted to reflect year end wage and employee levels for each Company and FirstEnergy Service Company that were developed in Adjustment No. 4, Supporting Schedule No. 1.

Q. Please describe Adjustment No. 7 to Administrative and General Expense.

A. Administrative and General Expense is adjusted to reflect: (1) year-end wage and employee levels for each Company and FirstEnergy Service Company that were developed in Adjustment No. 4, Supporting Schedule No. 1; (2) OPEBs at the service cost level; (3) pension expense at the ten-year average cash contribution level; (4) employee benefit expense at year-end personal and wage levels; (5) the elimination of non-jurisdictional administrative and general expenses based on the results of the separations study sponsored by Ms. Stewart (Met-Ed/Penelec/Penn Power/West Penn Statement No. 5); (6) inclusion of rate case expenses incurred in the current proceeding normalized over a two-year period; (7) the elimination of budgeted rate case expenses; and (8) the amortization of costs to allow for accelerated, three day, customer switching from one supplier to another based upon information contained in Exhibits RAD-64.

Supporting Schedule No. 1 adjusts the budgeted level of OPEB expenses to the service cost level. The budgeted OPEB expense consists of the current service cost, adjustments to prior years' service costs, and the financing component. The service cost represents the actuarial present value of benefit liabilities accrued

under the plan benefit formula for services rendered during the test year. Inclusion of the service cost in rates provides for recovery of the current cost of benefits earned by plan participants. Any excess or shortfall related to the expected return on plan assets is excluded because its inclusion would artificially reduce or increase total costs and result in the recovery of more or less than the normal ongoing cost of service. The adjustment to restate OPEB expense at the current service cost level was adopted by the Commission at Docket Nos. R-00061366 and R-00061367.

Supporting Schedule No. 2 normalizes the budgeted level of pension expense to appropriately reflect a ten-year historical average level of actual cash contributions to the pension plan under the methodology that was adopted by the Commission at Docket Nos. R-00061366 and R-00061367.

Supporting Schedule No. 3 uses the O&M payroll expense developed in Adjustment No. 4, Supporting Schedule No. 1 to normalize the employee benefits costs charged to Administrative and General expense.

Q. Please describe Adjustment No. 8 to Depreciation Expense.

A. Budgeted Depreciation Expense is adjusted: (1) to reflect the application of average remaining life depreciation rates to claimed plant in service; (2) to remove depreciation expense attributable to non-jurisdictional assets; (3) to restate the cost of removal/salvage expense on a five-year average basis consistent

with Commission practice; and (4) to amortize the unrecovered investment in legacy meters at April 30, 2016 over five years.

Q. Please describe Adjustment No. 9.

A. This adjustment increases expenses to amortize storm damage expenses that have been deferred with the Commission's prior approval. The specific costs deferred, and a citation to the Commission Order approving their deferral, is provided for each Company on page 24 of the exhibits. This adjustment also eliminates credits that were budgeted in this account for rate case expenses and legacy meters. The underlying expenses were inadvertently budgeted to Administrative and General Expense but were removed from the budget in Adjustment No. 7.

Q. Please describe Adjustment No. 10.

A. Taxes Other Than Income Taxes included in the budget were adjusted to: (1) eliminate non-jurisdictional payroll taxes: (2) reflect GRT at 5.9% for normalized sales revenues; (3) eliminate non-jurisdictional expense portions of Capital Stock Tax, the Public Utility Reality Tax, and other real estate taxes; and (4) adjust payroll tax expense based on annualized payroll and employee levels.

The adjustments to remove the non-jurisdictional portion of payroll taxes, the Capital Stock Tax, Public Utility Reality Tax, and other real estate taxes are based on the results of the separation study performed by Ms. Stewart.

Supporting Schedule No. 1 shows the calculation of Federal Insurance Contributions Act ("FICA") tax associated with the annualized O&M payroll expense developed in Adjustment No. 4.

Q. Please describe briefly the computation of federal and state income taxes as reflected in Adjustment No. 11.

A. This schedule begins with the computation of the $57,147,000 net operating income before income taxes from data shown on page 1 of Met-Ed Exhibit RAD-2 (line 5 less line 14 of column 3 on page 1); $100,404,000 net operating income before income taxes from data shown on page 1 of Penelec Exhibit RAD-2 (line 5 less line 14 of column 3 on page 1); $22,637,000 net operating income before income taxes from data shown on page 1 of Penn Power Exhibit RAD-2 (line 5 less line 14 of column 3 on page 1), and $67,368,000 net operating income before income taxes from data shown on page 1 of West Penn Exhibit RAD-2 (line 5 less line 14 of column 3 on page 1). The revenues and expenses used to calculate the federal and state income taxes in Adjustment No. 11 are divided into columns corresponding to the components shown on pages 1-3 of these exhibits (Distribution, PTC, USC, EE&C-C, Smart Meter Technologies Charge Rider, DSS Rider, SPVRC, NUG and Storm Cost Recovery Rider) to derive net operating income before income taxes. From that amount, interest was deducted. Interest was calculated by multiplying the adjusted rate base by the weighted average cost of long-term debt. The resulting figure is net income before income taxes a shown on line 10.

Two adjustments (lines 11 and 14) were made to increase taxable income. The first reflects the five-year amortization of net salvage. The second increases net income by adding back the cash pension contribution included in pro forma O&M expenses, which is not a current deduction for tax purposes.

The remaining two adjustments (lines 12 and 13) are deductions from taxable income. The first adjusts depreciation to reflect accelerated depreciation, where permitted, on eligible property as of April 30, 2016. The second reflects cost of removal ($6,080,000 for Met-Ed; $8,872,000 for Penelec; $527,000 for Penn Power; $4,938,000 for West Penn) that may be claimed as a current deduction for tax purposes. The net amount of these adjustments is included in the net income before federal and state income taxes to determine the income subject to state income tax. The state and federal income tax calculations then follow. The state and federal income taxes are computed at the statutory rates of 9.99% and 35%, respectively.

Q. Please describe Adjustment No. 12.

A. This adjustment eliminates from the budgeted Provision for Deferred Income Taxes all deferred taxes except the federal deferred taxes associated with liberalized depreciation. Additionally, federal deferred taxes for liberalized depreciation are adjusted to reflect plant in service as of the end of the FPFTY. Detailed calculations of the federal deferrals are provided in Exhibits RAD-41.

The computation for post-1969 through 1980 “expansion” property is based on the difference between accelerated depreciation (calculated using the Sum of the Years Digits (“SYD”) method and taxable lives based on the Asset Depreciation Range (“ADR”)) and straight-line depreciation using “guideline” lives. The computation for 1981 and subsequent property begins by determining the difference between tax depreciation using the Accelerated Cost Recovery System (“ACRS”) and the Modified Accelerated Cost Recovery System (“MACRS”) and straight line depreciation (using book rates and tax basis).

The federal tax rate of 35% was applied to the amounts calculated in the manner described above and compared to the tax to be booked during the test year to determine the adjustment to deferred taxes.

The state deferred taxes associated with liberalized depreciation pertain only to FERC jurisdictional property and have been eliminated. The deferred taxes associated with other miscellaneous items have been eliminated because the associated income has not been included in the calculation of taxable income used to compute federal and state taxes included in each Company’s revenue requirement.

Q. Please describe Adjustment No. 13.

A. This adjustment eliminates the non-jurisdictional portion of investment tax credits based on the results of the separation study performed by Ms. Stewart.

Q. What is Met-Ed's claimed additional distribution revenue requirement?

A. Reflecting all of the adjustments to the budget data discussed above, Met-Ed's net utility operating income for the FPFTY at present rates is $29,730,000 (page 1, column 13, line 23). This amount, compared to the $113,767,000 shown on page 3, column 33, line 23, shows that $84,037,000 in additional return is required for Met-Ed to achieve an overall return of 8.05% on its distribution rate base. This translates into an additional base rate revenue requirement, or revenue deficiency under existing rates, of $152,643,000, as shown on page 2, column 23, line 1.

Q. What is Penelec's claimed additional distribution revenue requirement?

A. Reflecting all of the adjustments to the budget data discussed above, Penelec's net utility operating income for the FPFTY at present rates is $61,695,000 (page 1, column 14, line 23), after excluding ($726,000) allocated to the New York jurisdiction. This amount, compared to the $127,934,000 shown on page 3, column 34, line 23, shows that $66,239,000 in additional return is required for Penelec to achieve an overall return of 8.31% on its Pennsylvania jurisdictional distribution rate base. This translates into an additional base rate revenue requirement, or revenue deficiency under existing rates, of $120,316,000, as shown on page 2, column 24, line 1.

Q. What is Penn Power's claimed additional distribution revenue requirement?

A. Reflecting all of the adjustments to the budget data discussed above, Penn Power's net utility operating income for the FPFTY at present rates is $14,278,000 (page 1, column 13, line 23). This amount, compared to the $30,550,000 shown on

page 3, column 33, line 23, shows that $16,272,000 in additional return is required for Penn Power to achieve an overall return of 8.51% on its distribution rate base. This translates into an additional base rate revenue requirement, or revenue deficiency under existing rates, of $29,557,000, as shown on page 2, column 23, line 1.

Q. What is West Penn's claimed additional distribution revenue requirement?

A. Reflecting all of the adjustments to the budget data discussed above, West Penn's net utility operating income for the FPFTY at present rates is $61,502,000 (page 1, column 11, line 23). This amount, compared to the $104,785,000 shown on page 3, column 27, line 23, shows that $43,283,000 in additional return is required for West Penn to achieve an overall return of 8.14% on its distribution rate base. This translates into an additional base rate revenue requirement, or revenue deficiency under existing rates, of $78,619,000, as shown on page 2, column 19, line 1.

Q. What is contained in Exhibits RAD-3, RAD-4, RAD-5 and RAD-6?

A. Exhibits RAD-3 and RAD-5 set forth each Company’s rate base at March 31, 2015 and 2014, respectively. Exhibits RAD-4 and RAD-6 set forth each Company’s operating income statements with normalizing adjustments for the future test year (twelve months ended March 31, 2015) and the historic test year (twelve months ending March 31, 2014), respectively.

While the specific numbers differ, these two sets of exhibits are identical in format and concept to Exhibits RAD-1 and RAD-2 and the description of the filing format in my testimony applies equally to them.

V. REGULATORY TREATMENT OF STORM DAMAGE COSTS

Q. How has the Commission historically treated storm damage costs for ratemaking purposes?

A. As in the case of other operating expenses, utilities have been allowed to include a normal, ongoing level of storm damage costs in their base rate revenue requirement. In addition, utilities have been permitted to request authorization to defer, for accounting purposes, extraordinary storm damage costs, with the understanding that rate recovery of the deferred costs would be addressed in a future base rate proceeding. In accordance with that policy and prior rulings by the Commission, the Companies have included in their FPFTY revenue requirement a normalized level of storm damage costs and, in the case of Met-Ed, Penelec and West Penn, rate recovery of previously authorized deferrals (see Exhibits RAD-1, p. 7 and Exhibits RAD-2, p. 24).

Q. Are the Companies proposing any changes to the recovery of storm damage expense in this filing?

A. Yes. The Companies are proposing to institute a Storm Damage Recovery Rider to provide for the annual true-up of actual storm damage O&M expenses. The Riders would impose either a charge, if actual storm damage expenses exceeded the base rate amount, or a credit if actual storm damage expenses were less than

the base rate amount. Ms. Bortz, in Met-Ed/Penelec/Penn Power/West Penn Statement No. 3, describes the Storm Damage Recovery Riders proposed by the Companies.

Q. What is the normalized, ongoing amount of storm damage O&M expense budgeted for the twelve months ending April 30, 2016?

A. Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-63 set forth budgeted storm damage expense for the twelve months ending April 30, 2016, and the twelve months ending March 31, 2015, and actual storm damage expense for the twelve months ended March 31, 2014, along with three additional historical calendar years. The level of storm damage O&M expense to be recovered through base rates is $6,625,000 at Met-Ed, $5,111,000 at Penelec, $657,000 at Penn Power, and $5,276,000 at West Penn.

VI. COSTS ASSOCIATED WITH IMPLEMENTATION OF ACCELERATED CUSTOMER SWITCHING

Q. You noted previously that the Commission had ordered EDCs to accelerate the processing of supplier switching requests. What led to this directive?

A. Weather conditions earlier this year were unusually harsh and resulted in unanticipated fluctuations in wholesale and retail energy prices. Customers with variable rate supply contracts were adversely impacted by these developments and, in response, the Commission launched a Rulemaking with the goal of ensuring that customers could quickly switch electric suppliers to mitigate their exposure to the types of price fluctuations they had experienced.

Q. How did the Commission proceed with the Rulemaking?

A. On March 18, 2014 at Docket No. L-2014-2409383, the Commission issued a Secretarial Letter informing EDCs, the Office of Consumer Advocate and the Office of Small Business Advocate of a proposed Rulemaking to amend existing Regulations at 52 Pa. Code, Chapter 57. The Rulemaking directed EDCs to take the necessary steps to permit retail customers to switch suppliers within three days or less. The Commission recognized the proposed changes were significant and provided for a comment period.

Q. What was the outcome of the Commission's Rulemaking at Docket No. L-2014-2409383?

A. The Commission revised its regulations to facilitate accelerated customer switching in its Order at Docket No. L-2014-2409383, entered April 3, 2014. The Rulemaking Order ensures customers may easily and quickly switch electric suppliers in an effort to mitigate potential price impacts related to variable priced contracts and fluctuations in the wholesale and retail energy markets. The Rulemaking Order also allows for the recovery in an EDC's next base rate proceeding of the cost incurred to comply with the accelerated switching requirements.

Q. What is contained in the Companies' respective Exhibits RAD-64?

A. Exhibits RAD-64 identify the incremental O&M expenses and capital expenditures to be incurred by each Company to comply with the Commission's three-day switching requirement. Those costs are then added to each Company's

revenue requirement through an adjustment to Administrative and General expense on page 18 of Exhibits RAD-2. As indicated on page 1 of Exhibits RAD-64, the Companies are proposing that the additional capital expenditures be amortized over five years.

VII. OTHER FILING REQUIREMENTS

Q. Would you briefly describe Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-7 through RAD-62?

A. Yes. 52 Pa. Code § 53.53 contains the data requirements to be filed in a major rate case. Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-7 through RAD-60 contain the Companies' responses to various data requests assigned to me. Each exhibit cites the specific filing requirement to which it is responding and is followed by the Companies' response.

Met-Ed, Penelec, Penn Power, and West Penn Exhibits RAD-61 list the types of advertising included in expenses for the test year and the immediately preceding year, in accordance with Section 1316(c) of the Public Utility Code, 66 Pa. Code Sec. § 1316(c). Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-62 respond to the PUC Statement of Policy at 52 Pa. Code § 69.36, entitled "Performance criteria regarding energy supply alternatives." This Statement of Policy identifies six areas for review in rate proceedings pertaining to an electric utility's efforts to encourage the development of cost effective energy supply alternatives. Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-62

address five of the six identified areas. Mr. Siedt addresses the remaining area in Met-Ed/Penelec/Penn Power/West Penn Statement No. 4.

VIII. CONCLUSION

Q. Please summarize your testimony and recommendations.

A. Inclusive of the roll-in of smart meter costs, Met-Ed has supported an increase in base rate revenue requirements of $152,643,000; Penelec an increase of $120,316,000; Penn Power an increase of $29,557,000; and West Penn an increase of $78,620,000 (including the separate USC Rider).

In addition, West Penn is proposing a separate reconciling cost recovery rider for universal service costs as explained by Ms. Bortz in Met-Ed/Penelec/Penn Power/West Penn Statement No. 3. If the USC Rider is not adopted by the Commission, an additional revenue requirement of $29,565,000 (see West Penn Exhibit RAD-2, page 7) would need to be reflected in West Penn's base distribution rates.

Finally, and as previously discussed, the Companies are proposing to implement Storm Damage Recovery Riders to provide for the recovery of storm damage expenses in excess of – or the crediting of storm damage expenses falling below – a normalized level of storm damage costs reflected in base distribution rates. Ms. Bortz describes these Riders in Met-Ed/Penelec/Penn Power/West Penn Statement No. 3.

Q. Mr. D’Angelo, does this complete your direct testimony?

A. Yes, it does.

Resume: Education and Experience of Richard A. D'Angelo

Education:

1972	Bachelor of Science Degree in Economics - Brooklyn College
1976	Master of Business Administration Degree in Finance - Pace University

Experience:

9/72 - 11/76	Accountant and Supervisor - Bankers Trust Company
11/76 - 2/81	Employed as Accountant within Regulatory Accounting Area - Metropolitan Edison Company ("Met-Ed")
2/81 - 2/82	Senior Accountant within Regulatory Accounting Area with special emphasis on rate-related matters (Met-Ed)
2/82 - 2/83	Supervisor - Rates and Financing (Met-Ed)
2/83 - 3/95	Manager - Rate Revenue Requirements within the Rate Department (Met-Ed)
3/95 - 8/96	Manager - Regulatory Liaison within the Regulatory Affairs and Pricing Department (Met-Ed/Penelec)
8/96 – 11/01	Manager - Rate Activity within the Rate Department (GPU Energy)
11/01 – Present	Manager – Rates & Regulatory Affairs- Pennsylvania (FirstEnergy Service Company)

Prepared and presented testimony in the following rate-related cases:

Pa. P.U.C. Cases: Docket Nos. P-2011-2273650
P-2011-2273668
P-2011-2273669
P-2011-2273670
A-2010-2176520
A-2010-2176732
P-2010-2157862
P-2009-2093053
P-2009-2093054
P-00072305
P-00072259
P-00062235
R-00061366
R-00061367
P-00062213

P-00062214
P-00052149
P-00062214
P-00052188
A-110550F0160
R-00016851C0001
R-00016852C0001
R-00016853C0001
A-110300F.0095
A-110400F.0040
P-00001860
P-00001861
P-00001837 (Phase 2)
P-00001838 (Phase 2)
R-00974008 (Phase 1)
R-00974009 (Phase 1)
P-00971215
P-00971216
P-00971217
P-00971223
P-00971278
P-00961015
P-00950968
A-110300 F0067
R-922314
P-0092087
P-00900450
R-860384
R-842770
R-832549
R-822249
I-900005
P-890366
M-FACE 8707
M-FACE 8602
M-FACE 8506
M-FACE 8404
M-FACE 8203

M-FACE 8104
M-870171 C001

NJ B.P.U Case: Docket No. EO03121014
Docket No. ER12111052

FERC Cases: Docket Nos. ER-90-388-000 and ER-90-522-000
ER-87-34-001
ER-83-173

Assisted in development and preparation in the following rate cases:

Pa. P.U.C. Cases: Docket Nos. R-811601
R-80051196
R.I.D. 626

FERC Case: Docket No. ER-79-58

METROPOLITAN EDISON COMPANY
Rate Base At Original Cost
Normalized To Year-End Conditions at April 30, 2016
($000)

Line No.	Description	Per Budget	Adjustments and Normalizations	Adj No.	Total	Pa Juridictional Normalized Rate Base: Distribution	Smart Meter Costs	PA Jurisdictional Total
		(1)	(2)		(3)	(4)	(5)	(6) = (4) + (5)
	Electric Plant:							
1	Plant in service	$ 2,935,437	$ (669,581)	1	$ 2,265,856	$ 2,231,833	$ 34,023	$ 2,265,856
2	Plant held for future use	596	(596)	2	-	-	-	-
3	Construction work in progress - pollution control and safety	-	-		-	-	-	-
4	Total electric plant	$ 2,936,033	$ (670,177)		$ 2,265,856	$ 2,231,833	$ 34,023	$ 2,265,856
	Depreciation & Amortization Reserve:							
5	Plant in service	$ 1,055,494	$ (304,192)	3	$ 751,302	$ 747,774	$ 3,528	$ 751,302
6	Plant held for future use	-	-		-	-	-	-
7	Total depreciation & amortization reserve	$ 1,055,494	$ (304,192)		$ 751,302	$ 747,774	$ 3,528	$ 751,302
8	Net Electric Plant	$ 1,880,539	$ (365,985)		$ 1,514,554	$ 1,484,059	$ 30,495	$ 1,514,554
	Additions:							
9	Cash working capital	$ -	$ 147,828	4	$ 147,828	$ 147,828	$ -	$ 147,828
10	M&S inventories	-	14,493	5	14,493	14,493	-	14,493
11	Deferred storm damage	-	64,964	6	64,964	64,964		64,964
12	Legacy meters	-	53,794	7	53,794	53,794		53,794
13	Total additions	$ -	$ 281,079		$ 281,079	$ 281,079	$ -	$ 281,079
	Deductions:							
14	Customer deposits	$ 20,925	$ -		$ 20,925	$ 20,925	$ -	$ 20,925
15	Customer advances for construction	19	-		19	19	-	19
16	Accum. Deferred income taxes - Liberalized depreciation	495,161	(133,944)	8	361,217	358,831	2,386	361,217
17	Operating reserves (net of taxes)	653	(146)	9	508	508	-	508
18	Total deductions	$ 516,758	$ (134,090)		$ 382,669	$ 380,283	$ 2,386	$ 382,669
19	Total Rate Base	$ 1,363,781	$ 49,184		$ 1,412,965	$ 1,384,856	$ 28,109	$ 1,412,965
20	Pro forma return at present rates (PA Distribution)	$ 29,730	Dollars					
21		2.10%	Percent					
22	Pro forma return at proposed rates (PA Distribution)	$ 113,767	Dollars					
23		8.05%	Percent					

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 1
($000)

Adjustment of Electric Plant in Service

To adjust the budgeted gross plant in service to (1) eliminate the Asset Retirement Cost ("ARC") An asset retirement cost ("ARC") increases the carrying amount of a long-lived asset when a liability for an asset retirement obligation ("ARO") is recognized. The ARC is depreciated over the life of the asset. The ARC and related reserve are excluded from Rate Base, while the associated depreciation expense is excluded from the Income Statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18 Asset retirement obligations; (2) remove FERC Transmission Plant which is non-jurisdictional; (3) remove an allocated portion of Intangible Plant that supports FERC Transmission Plant; (4) remove an allocated portion of General Plant that supports FERC Transmission Plant; and (5) remove legacy meters as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Adjustments	Plant in Service	Cross Reference
		(1)	(2)	(3)
1	Budgeted Plant in Service at 4/30/2016		$ 2,935,437	Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2
	Normalizing adjustments:			
2	Eliminate ARC	$ (95,358)		Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2
3	Remove FERC Transmission Plant	(454,163)		Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2
4	Remove allocated portion of Intangible Plant associated with FERC Transmission Plant	(9,695)		Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2
5	Remove allocated portion of General Plant associated with FERC Transmission Plant	(43,570)		Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2
6	Remove legacy meters	(66,795)		Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2
7	Normalization adjustment		(669,581)	
8	Plant in Service at 4/30/2016, as adjusted		$ 2,265,856	Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 2
($000)

Adjustment of Plant Held for Future Use

To adjust Plant Held for Future Use. As an alternative to rate base treatment, the Company is requesting the allowance of deferred carrying charges on any current or future investments in Plant Held for Future Use with definitive plans of utilization within a ten-year period. This is consistent with long-standing Commission policy.

Line No.		Amount (1)
1	Per budget Plant Held for Future Use at 4/30/2016	$ 596
	Normalizing adjustment:	
2	Eliminate Plant Held for Future Use	(596)
3	Plant Held for Future Use at 4/30/2016, as adjusted	$ -

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 3
($000)

Adjustment of Depreciation Reserves - Plant In Service

To adjust the budgeted plant in service depreciation reserves to (1) eliminate the Asset Retirement Cost ("ARC") reserves. An asset retirement cost ("ARC") increases the carrying amount of a long-lived asset when a liability for an asset retirement obligation ("ARO") is recognized. The ARC is depreciated over the life of the asset. The ARC and related reserve are excluded from Rate Base, while the associated depreciation expense is excluded from the Income Statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18 Asset retirement obligations; (2) remove FERC Transmission Plant reserves which are non-jurisdictional; (3) remove an allocated portion of Intangible Plant reserves that support FERC Transmission Plant; (4) remove an allocated portion of General Plant reserves that support FERC Transmission Plant; (5) and remove legacy meters as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Adjustments	Depreciation Reserves Plant in Service	Cross Reference
		(1)	(2)	(3)
1	Plant in Service depreciation reserves at 4/30/2016		$ 1,055,494	Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
	Normalizing adjustments:			
2	Eliminate ARC	$ (95,344)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
3	Remove FERC Transmission Plant	(155,934)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
4	Remove allocated portion of Intangible Plant associated with FERC Transmission Plant	(6,012)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
5	Remove allocated portion of General Plant associated with FERC Transmission Plant	(30,270)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
6	Remove legacy meters	(16,632)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
7	Normalization Adjustment		(304,192)	
8	Plant in Service depreciation reserves at 4/30/2016, as adjusted		$ 751,302	Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 4
($000)

Adjustment of Cash Working Capital

To recognize cash working capital at year-end level. This adjustment is supported by Ms. P. M. Larkin.

Line No.		Cash Working Capital (1)	Cash Working Capital (2)
1	Cash working capital per budget at 4/30/2016		$ -
	Normalizing adjustment:		
2	Cash working capital normalized to year-end (Exhibit PML-1)	$ 147,828	
3	Cash working capital per budget	-	
4	Normalization Adjustment		147,828
5	Cash working capital at 4/30/2016, as adjusted		$ 147,828

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 5
($000)

Adjustment of Material and Supplies Inventories

To recognize the Company's distribution portion of FE Service material and supplies ("M&S") inventory levels projected at 4/30/2016.

Line No.		M&S Inventories (1)	M&S Inventories (2)
1	M&S Inventory per budget at 4/30/2016		$ -
	Normalizing adjustment:		
2	Distribution component of projected FE Service M&S Inventory allocated to Met-Ed at 4/30/2016 (Exhibit RAD-13)	$ 14,493	
3	M&S Inventory per budget at 4/30/2016	-	
4	Normalization Adjustment		14,493
5	M&S inventory at 4/30/2016, as adjusted		$ 14,493

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 6
($000)

Adjustment of Deferred Storm Damage Expenses

To include in rate base the deferred storm damage balances for Winter Storm Nika, approved at Docket No. P-2014-2412229, Hurricane Sandy, approved at Docket No. P-2013-2351260, and distribution non-capital storm expenses that exceeded 125% of storm costs included in base rates between the period of February 25, 2011 through September 30, 2012 as a result of the FirstEnergy and Allegheny Merger approved at Docket Nos. A-2010-2176520 and A-2010-2176732, including but not limited to Hurricane Irene, the October 2011 snowstorm, and Tropical Storm Lee.

Line No.		Storms (1)	Storms (2)
1	Unamortized storm deferral expense per budget at 4/30/2016		$ -
2	Deferred Nika storm damage	$ 13,327	
3	Deferred Sandy storm damage	21,497	
4	Merger storm damage deferral	30,140	
5	Normalization Adjustment (Lines 2 + 3 + 4)		64,964
6	Storm Expense at 4/30/2016 as adjusted		$ 64,964

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 7
($000)

Adjustment to Include Legacy Meters in Regulatory Asset

To include legacy meters in a regulatory asset as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Legacy Meters (1)	Legacy Meters (2)
1	Net legacy meters in regulatory asset		$ -
2	Legacy meters per budget at 4/30/2016	$ 66,795	
3	Net estimated cost of removal and salvage	3,631	
4	Depreciation reserve per budget at 4/30/2016	(16,632)	
5	Net legacy meters normalizing adjustment (Lines 2 + 3 +4)		53,794
6	Net legacy meters in regulatory asset as adjusted at 4/30/2016		$ 53,794

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 8
($000)

Adjustment of Accumulated Deferred Income Taxes - Liberalized Depreciation

This adjustment adjusts the budgeted deferred tax balances for liberalized depreciation (excluding the impact of SFAS No. 109 deferrals) to (1) eliminate the deferred income taxes - liberalized depreciation balances associated with TMI-2; (2) eliminate deferred income taxes - liberalized depreciation associated with other generation; (3) eliminate other excludable items (capital leases); (4) eliminate remaining state deferred taxes - liberalized depreciation balances including the federal benefit of those taxes; and (5) eliminate an allocated portion of the remaining federal deferred income taxes - liberalized depreciation balance associated with FERC Transmission Plant.

Line No.		Adjustments (1)	Accum Reserve for Deferred Taxes - Liberalized Depreciation (2)
1	Deferred taxes per budget - liberalized depreciation at 4/30/2016		$ 495,161
	Normalizing adjustments:		
2	Eliminate deferred income taxes - liberalized depreciation associated with TMI-2 (federal and state)	$ 2,792	
3	Eliminate deferred income taxes - liberalized depreciation associated with other generation (federal and state)	(93)	
4	Eliminate other excludable items - capital leases (federal and state)	(17,014)	
5	Eliminate remaining state deferred taxes - liberalized depreciation including the federal benefit of those taxes	(15,959)	
6	Eliminate an allocated portion of the remaining federal deferred income taxes - liberalized depreciation associated with FERC Transmission Plant	(103,670)	
7	Normalization Adjustment		(133,944)
8	Deferred taxes - liberalized depreciation at 4/30/2016, as adjusted		$ 361,217

METROPOLITAN EDISON COMPANY

Normalization Adjustment No. 9
($000)

Adjustment of Operating Reserves

To adjust operating reserves (net of accumulated deferred income taxes) to eliminate an allocated portion associated with FERC Transmission operations.

Line No.		Amount
1	Operating reserves, net of taxes, per budget at 4/30/2016	$ 653
	Normalizing adjustment:	
2	Eliminate portion of operating reserves associated with FERC Transmission operations	(146)
3	Operating reserves, net of taxes at 4/30/2016, as adjusted	$ 508

METROPOLITAN EDISON COMPANY

Rate of Return at April 30, 2016
($000)

Line No.	Description	Exhibit SRS-24 Capital Amounts (1)	Capital Ratios (2)	Cost Rate (3)	Weighted Cost Rate (4) = (2) X (3)
1	Total long-term debt	$ 849,707	50.04%	5.21%	2.61%
2	Total preferred stock	-	0.00%	0.00%	0.00%
3	Total Common Equit	848,489	49.96%	10.90%	5.44%
4	Total Capitalization	$ 1,698,196	100.00%		8.05%

Metropolitan Edison Company
Statement of Operating Income, 12 Months Ending April 30, 2016, Normalized and Adjusted
to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Per Budget	Normalizations & Adjustments	Adj. No.	Budget as Adjusted	Normalized PaPUC Jurisdictional										
							Riders									
						Distribution	Price to Compare	Universal Service	Energy Efficiency	Smart Meters	Default Service Support	Solar	NUG	Storm	PaPUC Total Distribution
		(1)	(2)		(3)=(1)+(2)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13) = (8) + (4)
	Operating revenues														
1	Retail sales	$ 656,675	$ 25	1	$ 656,700	$ 250,689	$ 286,330	$ 28,732	$ 27,285	$ 15,657	$ 39,190	$ 3,066	$ 5,751	$ -	$ 266,346
2	STAS revenue	-	-	2	-	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	12,678	-		12,678	-	12,678	-	-	-	-	-	-	-	-
4	Other operating revenue	72,265	(55,404)	3	16,861	18,593	(1,732)	-	-	-	-	-	-	-	18,593
5	Total operating revenue	741,618	(55,379)		686,239	269,282	297,276	28,732	27,285	15,657	39,190	3,066	5,751	-	284,939
	Operating expenses														
6	Price to Compare	278,274	-		278,274	-	275,732	-	-	-	-	2,542	-	-	-
7	Distribution	56,647	(8,731)	4	47,916	38,389	-	-	-	-	9,527	-	-	-	38,389
8	Customer accounts	23,271	1,457	5	24,728	17,325	-	-	-	-	7,403	-	-	-	17,325
9	Customer service & info	40,721	44	6	40,765	18,847	-	21,732	-	-	186	-	-	-	18,847
10	Admin & gen expense	41,116	14,207	7	55,323	22,326	-	-	24,313	8,684	-	-	-	-	31,010
11	Depreciation - accrual	64,431	11,737	8	76,168	72,727	-	-	-	3,441	-	-	-	-	76,168
12	Amortization & Accretion	38,376	22,686	9	61,062	21,656	8,026	6,265	1,362	434	17,508	399	5,412	-	22,090
13	Taxes other than income	45,795	(940)	10	44,855	20,901	16,893	1,695	1,610	924	2,312	181	339	-	21,825
14	Operating expense before tax	588,631	40,461		629,092	212,172	300,651	29,692	27,285	13,483	36,936	3,122	5,751	-	225,655
15	Operating income before income tax	152,987	(95,840)		57,147	57,111	(3,375)	(960)	-	2,174	2,254	(56)	-	-	59,285
	Income taxes														
16	Federal income tax - current	39,423	(20,174)	11	19,249	19,239	(1,063)	(302)	-	684	710	(18)	-	-	19,923
17	State income tax - current	-	6,104	11	6,104	6,101	(337)	(96)	-	217	225	(6)	-	-	6,318
18	Deferred income tax - federal	6,297	(2,699)	12	3,598	2,763	-	-	-	835	-	-	-	-	3,598
19	Deferred income tax - state	-		12	-	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	(364)	81	13	(283)	(283)	-	-	-	-	-	-	-	-	(283)
21	Total tax expense	45,356	(16,688)		28,668	27,819	(1,400)	(398)	-	1,736	935	(23)	-	-	29,555
22	Total operating expenses	633,987	23,773		657,760	239,991	299,251	29,294	27,285	15,219	37,871	3,099	5,751	-	255,210
23	**Operating income**	$ 107,631	$ (79,152)		$ 28,479	$ 29,292	$ (1,975)	$ (562)	$ -	$ 438	$ 1,319	$ (33)	$ -	$ -	$ 29,730

Metropolitan Edison Company
Statement of Operating Income, 12 Months Ending April 30, 2016, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Distribution	Riders: Price to Compare	Riders: Universal Service	Riders: Energy Efficiency	Riders: Smart Meters	Riders: Default Service Support	Riders: Solar	Riders: NUG	Riders: Storm	PaPUC Total Distribution
		(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23) = (14) + (18)
	Operating revenues										
1	Retail sales	$ 149,328	$ -	$ -	$ -	$ 3,315	$ -	$ -	$ -	$ -	$ 152,643
2	STAS revenue	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	-	-	-	-	-	-	-	-	-	-
4	Other operating revenue	-	-	-	-	-	-	-	-	-	-
5	Total operating revenue	149,328	-	-	-	3,315	-	-	-	-	152,643
	Operating expenses										
6	Price to Compare	-	-	-	-	-	-	-	-	-	-
7	Distribution	-	-	-	-	-	-	-	-	-	-
8	Customer accounts	-	-	-	-	-	-	-	-	-	-
9	Customer service & info	-	-	-	-	-	-	-	-	-	-
10	Admin & gen expense	-	-	-	-	-	-	-	-	-	-
11	Depreciation - accrual	-	-	-	-	-	-	-	-	-	-
12	Amortization	-	-	-	-	-	-	-	-	-	-
13	Taxes other than income	8,810	-	-	-	196	-	-	-	-	9,006
14	Operating expense before tax	8,810	-	-	-	196	-	-	-	-	9,006
15	Operating income before income tax	140,517	-	-	-	3,120	-	-	-	-	143,637
	Income taxes										
16	Federal income tax - current	44,268	-	-	-	983	-	-	-	-	45,251
17	State income tax - current	14,038	-	-	-	312	-	-	-	-	14,349
18	Deferred income tax - federal	-	-	-	-	-	-	-	-	-	-
19	Deferred income tax - state	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	-	-	-	-	-	-	-	-	-	-
21	Total tax expense	58,306	-	-	-	1,295	-	-	-	-	59,600
22	Total operating expenses	67,116	-	-	-	1,490	-	-	-	-	68,606
23	**Operating income**	$ 82,212	$ -	$ -	$ -	$ 1,825	$ -	$ -	$ -	$ -	$ 84,037

Metropolitan Edison Company
Statement of operating Income, 12 Months Ending April 30, 2016, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Distribution	Riders: Price to Compare	Riders: Universal Service	Riders: Energy Efficiency	Riders: Smart Meters	Riders: Default Service Support	Riders: Solar	Riders: NUG	Riders: Storm	PaPUC Total Distribution
		(24) = (4) + (14)	(25)	(26)	(27)	(28) = (8) + (18)	(29)	(30)	(31)	(32)	(33) = (24) + (28)
	Operating revenues										
1	Retail sales	$ 400,017	$ 286,330	$ 28,732	$ 27,285	$ 18,972	$ 39,190	$ 3,066	$ 5,751	$ -	$ 418,989
2	STAS revenue	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	-	12,678	-	-	-	-	-	-	-	-
4	Other operating revenue	18,593	(1,732)	-	-	-	-	-	-	-	18,593
5	Total operating revenue	418,610	297,276	28,732	27,285	18,972	39,190	3,066	5,751	-	437,582
		-				-				-	
	Operating expenses	-				-				-	
6	Price to Compare	-	275,732	-	-	-	-	2,542	-	-	-
7	Distribution	38,389	-	-	-	-	9,527	-	-	-	38,389
8	Customer accounts	17,325	-	-	-	-	7,403	-	-	-	17,325
9	Customer service & info	18,847	-	21,732	-	-	186	-	-	-	18,847
10	Admin & gen expense	22,326	-	-	24,313	8,684	-	-	-	-	31,010
11	Depreciation - accrual	72,727	-	-	-	3,441	-	-	-	-	76,168
12	Amortization	21,656	8,026	6,265	1,362	434	17,508	399	5,412	-	22,090
13	Taxes other than income	29,712	16,893	1,695	1,610	1,120	2,312	181	339	-	30,831
14	Operating expense before tax	220,982	300,651	29,692	27,285	13,679	36,936	3,122	5,751	-	234,661
		-				-				-	
15	Operating income before tax	197,628	(3,375)	(960)	-	5,294	2,254	(56)	-	-	202,922
		-				-				-	
	Income taxes	-				-				-	
16	Federal income tax - current	63,506	(1,063)	(302)	-	1,667	710	(18)	-	-	65,173
17	State income tax - current	20,138	(337)	(96)	-	529	225	(6)	-	-	20,667
18	Deferred income tax - federal	2,763	-	-	-	835	-	-	-	-	3,598
19	Deferred income tax - state	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	(283)	-	-	-	-	-	-	-	-	(283)
21	Total tax expense	86,124	(1,400)	(398)	-	3,031	935	(23)	-	-	89,155
		-				-				-	
22	Total operating expenses	307,107	299,251	29,294	27,285	16,709	37,871	3,099	5,751	-	323,816
		-									
23	**Operating income**	$ 111,503	$ (1,975)	$ (562)	$ -	$ 2,263	$ 1,319	$ (33)	$ -	$ -	$ 113,767
24	**Rate Base**	$ 1,384,856	-	$ -	$ -	$ 28,109	$ -	$ -	$ -	$ -	1,412,965
25	**Rate of Return overall**	8.05%				8.05%					8.05%
26	**Return on Equity**	10.90%				10.90%					10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Distribution
$000

Line No.	Description	Budget as Adjusted	Revenue Adjustment Required	Allowable Revenue
		(1)	(2)	(3)
	Operating revenues			
1	Retail sales	$ 250,689	$ 149,328	$ 400,017
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	18,593	-	18,593
5	Total operating revenue	269,282	149,328	418,610
	Operating expenses			
6	PTC	-	-	-
7	Distribution	38,389	-	38,389
8	Customer accounts	17,325	-	17,325
9	Customer service & info	18,847	-	18,847
10	Admin & gen expense	22,326	-	22,326
11	Depreciation - accrual	72,727	-	72,727
12	Amortization	21,656	-	21,656
13	Taxes other than income	20,901	8,810	29,712
14	Operating expense before tax	212,172	8,810	220,982
15	Operating income before tax	57,111	140,517	197,628
	Income taxes			
16	Federal income tax - current	19,239	44,268	63,506
17	State income tax - current	6,101	14,038	20,138
18	Deferred income tax - federal	2,763	-	2,763
19	Deferred income tax - state	-	-	-
20	Investment tax credit	(283)	-	(283)
21	Total tax expense	27,819	58,306	86,124
22	Total operating expenses	239,991	67,116	307,107
23	**Operating Income**	$ 29,292	$ 82,212	$ 111,503
24	**Rate Base**	1,384,856		1,384,856
25	**Rate of Return overall**	2.12%		8.05%
26	**Return on Equity**	-1.0%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Smart Meter
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 15,657	$ 3,315	$ 18,972
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	15,657	3,315	18,972
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	-	-	-
10	Admin & gen expense	8,684	-	8,684
11	Depreciation - accrual	3,441	-	3,441
12	Amortization	434	-	434
13	Taxes other than income	924	196	1,120
14	Operating expense before tax	13,483	196	13,679
15	Operating income before tax	2,174	3,120	5,294
	Income taxes			
16	Federal income tax - current	684	983	1,667
17	State income tax - current	217	312	529
18	Deferred income tax - federal	835	-	835
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	1,736	1,295	3,031
22	Total operating expenses	15,219	1,490	16,709
23	**Operating income**	$ 438	$ 1,825	$ 2,263
24	**Rate Base**	28,109		28,109
25	**Rate of Return overall**	1.56%		8.05%
26	**Return on Equity**	-2.10%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Total Distribution
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 266,346	$ 152,643	$ 418,989
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	18,593	-	18,593
5	Total operating revenue	284,939	152,643	437,582
	Operating expenses			
6	PTC	-	-	-
7	Distribution	38,389	-	38,389
8	Customer accounts	17,325	-	17,325
9	Customer service & info	18,847	-	18,847
10	Admin & gen expense	31,010	-	31,010
11	Depreciation - accrual	76,168	-	76,168
12	Amortization	22,090	-	22,090
13	Taxes other than income	21,825	9,006	30,831
14	Operating expense before tax	225,655	9,006	234,661
15	Operating income before tax	59,285	143,637	202,922
	Income taxes			
16	Federal income tax - current	19,923	45,251	65,173
17	State income tax - current	6,318	14,349	20,667
18	Deferred income tax - federal	3,598	-	3,598
19	Deferred income tax - state	-	-	-
20	Investment tax credit	(283)	-	(283)
21	Total tax expense	29,555	59,600	89,155
22	Total operating expenses	255,210	68,606	323,816
23	**Operating income**	$ 29,730	$ 84,037	$ 113,767
24	**Rate Base**	1,412,965		1,412,965
25	**Rate of Return overall**	2.10%		8.05%
26	**Return on Equity**	-1.0%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Universal Service Cost Rider
$000

Line No.	Description	Budget as Adjusted	Revenue Adjustment Required	Allowable Revenue
		(1)	(2)	(3)
	Operating revenues			
1	Retail sales	$ 28,732	$ -	$ 28,732
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	28,732	-	28,732
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	21,732	-	21,732
10	Admin & gen expense	-	-	-
11	Depreciation - accrual	-	-	-
12	Amortization	6,265	-	6,265
13	Taxes other than income	1,695	-	1,695
14	Operating expense before tax	29,692	-	29,692
15	Operating income before tax	(960)	-	(960)
	Income taxes			
16	Federal income tax - current	(302)	-	(302)
17	State income tax - current	(96)	-	(96)
18	Deferred income tax - federal	-	-	-
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	(398)	-	(398)
22	Total operating expenses	29,294	-	29,294
23	**Operating income**	(562)	-	(562)

Metropolitan Edison Company
Summary of Revenue Requirements
Storm Damage Rider
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ -	$ -	$ -
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	-	-	-
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	-	-	-
10	Admin & gen expense	-	-	-
11	Depreciation - accrual	-	-	-
12	Amortization	-	-	-
13	Taxes other than income	-	-	-
14	Operating expense before tax	-	-	-
15	Operating income before tax	-	-	-
	Income taxes	-		
16	Federal income tax - current	-	-	-
17	State income tax - current	-	-	-
18	Deferred income tax - federal	-	-	-
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	-	-	-
22	Total operating expenses	-	-	-
23	**Operating income**	$ -	$ -	$ -

Metropolitan Edison Company
Normalization Adjustment No. 1
$000

Adjustment of Base Operating Revenues

To adjust base operating revenues for (1) changes in the number of customers, (2) to roll in State Tax Adjustment Surcharge ("STAS") revenues into base rates, (3) to adjust for energy efficiency and behind the meter generation, (4) to adjust for other revenues and (5) to eliminate unbilled revenues. The adjustment for unbilled revenues is supported by Mr. R. A. D'Angelo. Adjustments (1) through (4) are supported by Mr. K. M. Siedt.

Line No.	Description	Amount (1)	Amount (2)
1	Base revenues per budget for the 12 months ending 4/30/16		$ 656,675
	Normalizing adjustments:		
2	Customers - increase to yr end level	$ 502	
	Specific adjustments		
3	Roll-in of STAS	-	
4	Adjust for Energy Efficiency and Behind the Meter Generation	(457)	
5	Adjust for Other Revenues	41	
6	Eliminate unbilled revenues	(61)	
7	Total	$ (477)	
8	Normalizing adjustment (Lines 2+7)		25
9	Base revenues per budget for the 12 months ending 4/30/2016, as adjusted		$ 656,700

Metropolitan Edison Company
Normalization Adjustment No. 2
$000

Adjustment of State Tax Adjustment Surcharge Revenues

To remove state tax adjustment surcharge ("STAS") revenues. Normalized STAS revenues are being rolled into base rates.

Line No.	Description	Amount (1)
1	STAS revenue per budget for the 12 months ending 4/30/2016	$ -
2	Eliminate per budget STAS	-
3	Other operating revenue per budget for the 12 months ending 4/30/2016, as adjusted	$ -

Metropolitan Edison Company
Normalization Adjustment No. 3
$000

Adjustment of Other Operating Revenues

To adjust other operating revenue to eliminate non-jurisdictional transmission revenues.

Line No.	Description	Amount (1)
1	Other operating revenue per budget for the 12 months ending 4/30/2016	$ 72,265
2	Eliminate non-jurisdictional transmission revenues	(55,404)
3	Other operating revenue per budget for the 12 months ending 4/30/2016, as adjusted	$ 16,861

Metropolitan Edison Company
Normalization Adjustment No. 4
$000

Adjustment of Distribution Expense

To adjust distribution payroll expense to reflect year end wage and employee levels, to adjust service company distribution payroll expense to reflect year end wage and employee levels, eliminate non-jurisdictional transmission expense and to include the distribution portion of the amortization of gains or losses to reacquired debt. The plant and labor allocation factors used in this normalization adjustment are supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	Amount (2)
1	Distribution expense per budget for the 12 months ending 4/30/2016		$ 56,647
2	Distribution payroll expense adjustment to reflect year end employee levels, and ongoing wage and salary rates (Supporting Schedule No. 1, Line 12, Column 1)	$ 263	
3	Service Company Distribution payroll expense adjustment allocated to Met-Ed to reflect year end employee levels, and ongoing wage and salary rates (Supporting Schedule No. 1, Line 21, Column 1)	66	
4	Eliminate non-jurisdictional transmission expense	(9,140)	
5	Amortization of (gain) or loss on reacquired debt	$ 104	
6	Allocation ratio based on distribution plant	77.70%	
7	Distribution portion of (gain) or loss	$ 81	
8	Total normalizing adjustment (Lines 2 + 3 + 4 + 7)		(8,731)
9	Distribution expense per budget for the 12 months ending 4/30/2016, as adjusted		$ 47,916

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 4
($000)

Adjustment to Payroll Expense to Reflect Year End Employee Levels and Wage Rates

Line No.	Description		Amount (1)	Amount (2)
1	Total payroll per budget for the 12 months ending 4/30/2016 (Exhibit RAD-27)			$ 61,177
	Bargaining			
2	Straight time per budget for the 12 months ending 4/30/2016		$ 36,777	
3	Straight time 2.5% increase effective 5/1/2016 (Line 2 x 2.5%)		919	
	Non-Bargaining			
4	Straight time per budget for May 1, 2015 through February 28, 2016		13,205	
5	Straight time 3% increase effective 3/1/2016 (Line 4 x 3%)		396	
6	Total company payroll adjustment (Line 3 + Line 5)			1,316
7	O&M allocation %		39.67%	
8	O&M payroll as adjusted (Line 6 X Line 7)		$ 522	
9	Total Payroll adjustment (Line 1 + Line 6)			$ 62,493
	Allocation of payroll adjustment:			
10	Price to Compare	0.00%	$ -	
11	Transmission	8.91%	47	
12	Distribution	50.40%	263	
13	Customer accounts	17.72%	92	
14	Customer service	8.42%	44	
15	Administrative and general	14.55%	76	
16	Total	100%	$ 522	
	Service Company (Exhibit RAD-25)			
17	Straight time per budget for May 1, 2015 through February 28, 2016		$ 11,216	
18	Straight time 3% increase effective 3/1/2016 (Line 17 x 3%)		$ 336	
	Allocation of Service Company payroll adjustment (Exhibit RAD-25):			
19	Price to Compare	0.00%	$ -	
20	Transmission	7.20%	24	
21	Distribution	19.52%	66	
22	Customer Accounting and Information	29.33%	99	
23	Administrative and general	43.94%	148	
24	Total	100%	$ 336	

Metropolitan Edison Company
Normalization Adjustment No. 5
$000

Adjustment of Customer Accounts Expense

To adjust customer account expense to reflect year end wage and employee levels, service company year end wage and employee levels, increased costs associated with added customers, and interest on customer deposits.

Line No.	Description	Amount (1)	Amount (2)
1	Customer Account expense per budget for the 12 months ending 4/30/2016		$ 23,271
2	Customer Account payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates (Normalizing Adjustment No. 4, Supporting Schedule No. 1, Line 13, Column 1)	$ 92	
3	Service Company customer account payroll expense adjustment allocated to Met-Ed to reflect year end employee levels and ongoing wage & salary rates (Normalizing Adjustment No. 4, Supporting Schedule No. 1, Line 22, Column 1)	99	
4	Increased O&M costs associated with increased number of customers in normalized revenue levels (Supporting Schedule 1, Line 10)	10	
5	Interest on customer deposits (Supporting Schedule 2, Line 3)	1,256	
6	Total normalizing adjustment (Lines 2 + 3 + 4 + 5)		1,457
7	Customer Account expense per budget for the 12 months ending 4/30/2016, as adjusted		$ 24,728

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 5
($000)

Adjustment of Other O&M Costs Associated with Serving New Customers

In association with the additional revenues from added customers reflected in Adjustment No. 1, there is also a cost associated with serving those customers. The Commission has previously recognized this and approved an adjustment to customer accounts expense for this increased cost. This cost is estimated by determining the ratio of non-payroll customer account expense to distribution revenues from customers and applying this ratio to the additional revenue received from increased customers. The distribution revenues are supported by Mr. K. M. Siedt.

Line No.	Description	Amount (1)
	Customer Account Expense Excluding Labor and Uncollectible	
1	Customer Account expense per budget for the 12 months ending 4/30/2016	$ 23,271
2	Less: uncollectible expense	(12,136)
3	Less: Labor expense	(5,879)
4	Customer Account expense excluding labor and uncollectible expense	$ 5,256
	Total Base Revenue	
5	Distribution revenues per budget	$ 250,602
6	Late payment charges per budget	3,229
7	Total	$ 253,831
8	Ratio of customer account expense to distribution revenue (Line 4 / Line 7)	2.07%
9	Revenue from added customers (Adjustment No. 1, Line 2)	$ 502
10	Additional expense from added customers (Line 8 X Line 9)	$ 10

Metropolitan Edison Company
Supporting Schedule No. 2 to Normalizing Adjustment No. 5
($000)

Adjustment to Allow for Interest Expense on Customer Deposits

Customer deposits are included in rate base as a deduction, since these are funds supplied by customers to the company. Interest paid to customers on these deposits correspondingly has been recognized by the Commission as a expense when setting rates.

Line No.	Description	Amount (1)
1	Customer deposits included in rate base (Exhibit RAD-1 Column 1, Line 14)	$ 20,925
2	Interest rate on deposits	6%
3	Interest expense on customer deposits	$ 1,256

Metropolitan Edison Company
Normalization Adjustment No. 6
$000

Adjustment of Customer Service and Information Expense

To adjust customer service and information expense to reflect year end wage and employee levels.

Line No.	Description	Amount (1)	Amount (2)
1	Customer Service expense per budget for the 12 months ending 4/30/2016		$ 40,721
2	Customer Service payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates, (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 14, Column 1)	$ 44	
3	Total normalizing adjustment		44
4	Customer Service expense per budget for the 12 months ending 4/30/2016, as adjusted		$ 40,765

Metropolitan Edison Company
Normalization Adjustment No. 7
$000

Adjustment of Administrative and General Expense

To adjust Administrative and General expenses to reflect year end wage and employee levels, service company year end wage and employee levels, OPEB expense at the service cost level, pension expense to the ten year cash level, employee benefits expenses at year end personnel and wage levels, the elimination of non-jurisdictional administrative and general expenses, normalization of rate case expenses, eliminate legacy meters from the budget, and include costs to update computer system to allow accelerated (3 day) switching from one supplier to another. Hillary Stewart supports the non-jurisdictional expense allocation factor.

Line No.	Description	Amount (1)	Amount (2)
1	Administrative & general expense per budget for the 12 months ending 4/30/2016		$ 41,116
2	Administrative & general expenses related to EE&C	$ (24,313)	
3	Administrative & general expenses related to Smart Meters	(8,684)	
4	Adjustment to administrative & general expenses	(32,997)	
5	Net administrative & general expenses related to distribution	8,119	
6	Administrative & general payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates, (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 15, Column 1)	$ 76	
7	Service Company Administrative & general payroll expense adjustment allocated to Met-Ed to reflect year end employee levels and ongoing wage & salary rates (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 23, Column 1)	148	
8	Adjust OPEB expense to service cost level (Normalization Adjustment No. 7, Supporting Schedule No. 1, Line 12, Col. 1)	2,814	
9	Adjust pension expense to ten year cash level (Supporting Schedule No. 2, Line 18, Col. 3)	14,046	
10	Adjust employee benefit costs (Supporting Schedule No. 3, Line 8, Column 3	305	
11	Subtotal of adjustments (Lines 6 + 7 + 8 + 9 + 10)		17,389
12	Administrative and general expense, adjusted	$ 25,508	
13	Non-jurisdictional expense allocation factor	10.43%	
14	Non-jurisdictional administrative and general expense		(2,660)
15	Rate case expenses to be incurred during current rate proceeding (Exhibit RAD-23)	$ 495	
16	Recovery period - years	2	
17	Annual amount (Line 15 / Line 16)	$ 248	
18	Less rate case expenses in budget	(750)	
19	Adjusted total		$ (502)
20	Less legacy meters from budget		(330)
21	Increase in O&M costs for accelerated (3 day) switching for customers moving to a new supplier (Exhibit RAD-64)		311
22	Total normalizing adjustment (Lines 11 + 14 + 19 + 20 + 21)		14,207
23	Administrative and general expense per budget for the 12 months ending 4/30/2016, as adjusted		$ 55,323

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 7
$000

Adjustment for OPEB Expense

Budgeted OPEB expense consists of the current service cost, adjustments to prior years' service costs, and the financing component. This schedule adjusts the total budgeted expense amounts to the service cost. The service cost represents the actuarial present value of benefit liabilities accrued under the plan benefit formula for services rendered during the test year. Inclusion of the service cost in rates provides for recovery of the current cost of benefits earned by plan participants. Any excess or shortfall related to the expected return on plan assets are not included because their inclusion would artificially reduce or increase total costs and result in the recovery of more or less than the actual normal cost of service. The adjustment for OPEB expense to the current service cost amount was adopted by the Commission at Docket Nos. R-00061366 and R-00061367.

Line No.	Description	O&M (1)	Capital (2)	Total (3)
1	O&M - Capital allocation ratios	39.67%	60.33%	100.00%
2	Company OPEB expense included in budget	$ (1,962)	$ (2,984)	$ (4,946)
3	FirstEnergy Service Corp. OPEB expense	$ (11,066)	$ (16,830)	$ (27,896)
4	Allocation ratio	5.54%	5.54%	5.54%
5	Allocated FirstEnergy Service Corp. OPEB expense included in budget (Line 3 X Line 4)	$ (613)	$ (932)	$ (1,545)
6	Total OPEB expense included in budget (Line 2 + Line 5)	$ (2,575)	$ (3,916)	$ (6,491)
7	Service cost for company OPEB expense	$ 222	$ 337	$ 559
8	Service cost for FirstEnergy Service Corp. OPEB expense	$ 303	$ 461	$ 764
9	Allocation ratio	5.54%	5.54%	5.54%
10	Allocated FirstEnergy Service Corp. service cost (Line 8 X Line 9)	$ 17	$ 25	$ 42
11	Total OPEB service cost (Lines 7 + 10)	$ 239	$ 362	$ 601
12	Adjustment to set OPEB expense at ongoing service cost level (Lines 11 - 6)	$ 2,814	$ 4,278	$ 7,092

Metropolitan Edison Company
Supporting Schedule No. 2 to Normalizing Adjustment No. 7
$000

Adjustment for Pension Expense

To adjust budget pension expense to a ten year historical average level of actual cash contributions under the methodology that was adopted by the Commission at Docket Number R-00061366 and R-00061367.

Line No.	Description	Amount (1) Total	(2) O&M %	(3) O&M
	Company Cash Contributions			
1	2004 Cash Pension Contribution	$ 38,823	56.52%	$ 21,943
2	2005 Cash Pension Contribution	35,912	56.52%	20,297
3	2007 Cash Pension Contribution	11,012	55.42%	6,103
4	2009 Cash Pension Contribution	123,521	50.49%	62,366
5	2011 Cash Pension Contribution	35,000	45.09%	15,782
6	Total Company Cash Pension Contributions	$ 244,268		$ 126,490
	FirstEnergy Service Company Cash Contributions			
7	2004 Pension Contribution	$ 91,633		
8	2004 Company Allocation Factor	8.91%		
9	2004 Service Company Pension Contribution allocated to the Company	$ 8,165	56.52%	$ 4,615
10	2007 Pension Contribution	$ 27,468		
11	2007 Company Allocation Factor	11.29%		
12	2007 Service Company Pension Contribution allocated to the Company	$ 3,101	55.42%	1,719
13	Total FirstEnergy Service Company Cash Pension Contributions allocated to the Company (Line 9 + Line 12)	$ 11,266		$ 6,333
14	Total Pension cash contributions (Line 6 + Line 13)	$ 255,534		$ 132,824
15	Average	10		10
16	Pension expense cash contribution, amortized over 10 years	$ 25,553		$ 13,282
17	O&M Pension Expense included in budget			(763)
18	Adjustment to Pension Expense (Line 16 - Line 17)			$ 14,046

Metropolitan Edison Company
Supporting Schedule No. 3 to Normalizing Adjustment No. 7
$000

Adjustment to Employee Benefit Expense to Reflect Year End Employee Levels and Ongoing Wage Rates

Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 8 increases the O&M payroll expense. Associated with that increase are employee benefits charged to Administrative and General expense. This adjustment computes the added benefit costs on a normalized basis.

Employee benefits applicable to operating expenses:

Line No.		Effective Rate (a)	Payroll Adjustment		Benefit Adjustment
		(1)	(2)		(3) = (1) X (2)
1	Workers compensation	0.700%	$ 522	(b)	$ 4
2	Pension costs	39.928%	$ 522	(b)	208
3	OPEB costs	0.913%	$ 522	(b)	5
4	Life insurance	0.149%	$ 522	(b)	1
5	Medical insurance	9.464%	$ 522	(b)	49
6	Savings Plan	4.616%	$ 522	(b)	24
7	Other	2.602%	$ 522	(b)	14
8	Total increase due to payroll adjustment				$ 305

(a) Summary of effective employee benefit rates based on total payroll for the 12 months ending 4/30/16

	Total Amount	Total Payroll	Effective Rate
Workers compensation (Exhibit RAD-27)	$ 428	$ 61,177	0.700%
Pension costs - normalized basis	24,427	61,177	39.928%
OPEB costs - service cost	559	61,177	0.913%
Life insurance (Exhibit RAD-27)	91	61,177	0.149%
Medical insurance (Exhibit RAD-27)	5,790	61,177	9.464%
Savings Plan (Exhibit RAD-27)	2,824	61,177	4.616%
Other (Exhibit RAD-27)	1,592	61,177	2.602%

(b) Adjustment No. 4, Supporting Schedule No. 1, Line 8.

Metropolitan Edison Company
Normalization Adjustment No. 8
$000

Adjustment of Depreciation Expense

To adjust budgeted depreciation expense to reflect average remaining life rates on adjusted rate base, to eliminate non-jurisdictional expense, and to adjust cost of removal/ salvage expense to a five year average amount, according to prior commission practice and the adjustment of legacy meters. The plant allocation factor used in this normalization adjustment are supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	(2)	(3)	(4)
1	Depreciation expense per budget for the 12 months ending 4/30/2016				$ 64,431
2	Cost of removal/salvage expense per budget for the 12 months ending 4/30/2016 (Exhibit RAD-30)		$ 4,509		
3	Depreciation accrual per budget (Line 1 - Line 2)		$ 59,922		
4	Jurisdictional depreciation expense accrual on adjusted rate base at average remaining life rates (Exhibit RAD-53, page 2)		52,881		
5	Adjustment for average remaining life accrual for jurisdictional plant (Line 4 - Line 3)			$ (7,041)	
6	Cost of removal/salvage expense per budget for the 12 months ending 4/30/16 (Exhibit RAD-30)		$ 4,509		
	Cost of removal and salvage (Exhibit RAD-30)				
7	4/1/2009 - 3/31/2010	$ 17,539			
8	4/1/2010 - 3/31/2011	7,101			
9	4/1/2011 - 3/31/2012	17,511			
10	4/1/2012 - 3/31/2013	28,248			
11	4/1/2013 - 3/31/2014	10,222			
12	Total	$ 80,621			
13	Five year average (Line 12 / 5)		$ 16,124		
14	Allocation ratio based on jurisdictional plant		77.70%		
15	Jurisdictional cost of removal/salvage expense to a jurisdictional five year average (Line 13 X Line 14)		12,529		
16	Adjustment of jurisdictional cost of removal/salvage expense to a jurisdictional five year average (Line 15 - Line 6)			8,020	
17	Adjustment for amortization of legacy meters (Adj. 8, Sched. 1, Line 7)			10,759	
18	Total normalizing adjustment (Lines 5 + 16 + 17)				11,737
19	Depreciation expense per budget for the 12 months ending 4/30/2016, as adjusted				$ 76,168

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 8
$000

Adjustment for Amortization for legacy meters

To amortize recovery of legacy meters to fully recover all legacy meter costs over 5 years.

Line No.	Description	Amount (1)	Amount (2)
1	Legacy meters per budget for the 12 months ending 4/30/2016	$ 66,795	
2	Depreciation reserve per budget for the 12 months ending 4/30/2016	16,632	
3	Net legacy meters per budget for the 12 months ending 4/30/2016	$ 50,163	
4	Net estimated cost of removal and salvage	3,631	
5	Net legacy meters	$ 53,794	
6	Annual amortization over a 5 year amortization period		$ 10,759

Metropolitan Edison Company
Normalization Adjustment No. 9
$000

Adjustment of Amortization Expense

To include the amortization of deferred storm damage balances for Winter Storm Nika, approved at Docket No. P-2014-2412229, Hurricane Sandy, approved at Docket No. P-2013-2351260, and distribution non-capital storm expenses that exceeded 125% of storm costs included in base rates between the period of February 25, 2011 through September 30, 2012 as a result of the FirstEnergy and Allegheny Merger approved at Docket Nos. A-2010-2176520 and A-2010-2176732, including but not limited to Hurricane Irene, the October 2011 snowstorm, and Tropical Storm Lee. In addition, rate case expenses, legacy meters, and accretion expenses are removed from the budget.

Line No.	Description	Amount (1)	Amount (2)	Amount (3)
1	Amortization expense per budget for the 12 months ending 4/30/2016			$ 38,376
2	Deferred Nika storm damage	$ 13,327		
3	Deferred Sandy storm damage	21,497		
4	Merger storm deferral	30,140		
5	Total deferred storms (Lines 2 + 3 + 4)	$ 64,964		
6	Amortized over 3 years	3		
7	Annual Amortization		$ 21,655	
8	Remove rate case expenses		750	
9	Remove legacy meters from budget		330	
10	Remove accretion expense		(49)	
11	Normalization adjustment (Lines 7 + 8 + 9 + 10)			22,686
12	Amortization expense per budget for the 12 months ending 4/30/2016, as adjusted			$ 61,062

Metropolitan Edison Company
Normalization Adjustment No. 10
$000

Adjustment of Taxes Other Than Income

To adjust gross receipts tax expense to reflect normalized sales revenues, to adjust payroll tax expenses for normalized payroll and employee expenses. The non-jurisdictional allocation factor is supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	Amount (2)	Amount (3)
1	Taxes Other Than Income per budget for the 12 months ending 4/30/2016			$ 45,795
2	Federal and State payroll taxes in budget (Exhibit RAD-32)	$ 4,694		
3	Non-jurisdictional percent	10.43%		
4	Eliminate non-jurisdictional payroll taxes		$ (490)	
5	Capital Stock Tax included in budget (Exhibit RAD-32)	$ 149		
6	PURTA tax in budget (Exhibit RAD-32)	1,976		
7	Real Estate tax in budget (Exhibit RAD-32)	131		
8	Total Other taxes	$ 2,256		
9	Non-jurisdictional percent	22.30%		
10	Eliminate non-jurisdictional taxes		(503)	
	Gross Receipts Tax			
11	Normalized sales revenues (Exhibit RAD-2, page 1, Col. 3)	$ 656,700		
12	Gross receipts tax @ 5.9%	38,745		
13	Gross receipts tax included in budget (Exhibit RAD-32)	38,732		
14	Adjustment for gross receipts tax at normalized revenue level (Line 12 - Line 13)		13	
15	Adjustment for payroll taxes on normalized payroll (Supporting Schedule No. 1, Line 8)		40	
16	Total normalizing adjustment (Lines 4+10+14+15)			(940)
17	Taxes other than income per budget for the 12 months ending 4/30/2016, as adjusted			$ 44,855

Metropolitan Edison Company
Supporting Schedule No.1 to Normalizing Adjustment No. 10
$000

Adjustment to Taxes Other Than Income to reflect changes in payroll taxes.

Normalization adjustments have been made to normalize O&M payroll expense. Associated with those payroll normalizations are changes in FICA tax amounts.

Line No.	Description	Amount (1)
1	Total payroll per budget for the 12 months ending 4/30/2016 (Normalization Adjustment No. 4, Schedule 1, Line 1, Col 2)	$ 61,177
2	Total payroll tax included in budget (Exhibit RAD-32)	4,694
3	Effective payroll tax rate (Line 2 / Line 1)	7.673%
4	Total payroll as adjusted (Normalization Adjustment No. 4, Schedule 1, Line 9, Col. 2)	$ 62,493
5	Payroll tax on normalized payroll (Line 3 x Line 4)	$ 4,795
6	Total Company payroll tax adjustment (Line 5 - Line 2)	$ 101
7	O&M Allocation percentage	39.67%
8	Adjustment for payroll tax (Line 6 x Line 7)	$ 40

Metropolitan Edison Company
Normalization Adjustment No. 11
$000

Computation of Federal & State Income Taxes - Normalized

Line No.	Description	Total Company Calculated Taxes (1)	Distribution Calculated Taxes (3)	PTC Calculated Taxes (2)	Universal Service Calculated Taxes (4)	Energy Efficiency Calculated Taxes (5)	Smart Meter Rider Calculated Taxes (6)	DSS Calculated Taxes (7)	Solar Calculated Taxes (8)	NUG Charge Calculated Taxes (9)	Storm Rider Calculated Taxes (10)
1	Total operating revenue	$ 686,239	$ 269,282	$ 297,276	$ 28,732	$ 27,285	$ 15,657	$ 39,190	$ 3,066	$ 5,751	$ -
2	Less: Total O& M Expense	447,006	96,887	275,732	21,732	24,313	8,684	17,116	2,542	$ -	$ -
3	Depreciation - accrual	63,640	60,199	-	-	-	3,441	-	-	-	-
4	Average net salvage	12,529	12,529	-	-	-	-	-	-	-	-
5	Amortization	61,062	21,656	8,026	6,265	1,362	434	17,508	399	5,412	-
6	Taxes other than income taxes	44,855	20,901	16,893	1,695	1,610	924	2,312	181	339	-
7	Total deductions	$ 629,092	$ 212,172	$ 300,651	$ 29,692	$ 27,285	$ 13,483	$ 36,936	$ 3,122	$ 5,751	$ -
8	Net operating income before income taxes	$ 57,147	$ 57,111	$ (3,375)	$ (960)	$ -	$ 2,174	$ 2,254	$ (56)	$ -	$ -
9	Less: Interest Charges (A)	36,822	36,089	-	-	-	733	-	-	-	-
10	Net income before income taxes	$ 20,325	$ 21,021	$ (3,375)	$ (960)	$ -	$ 1,441	$ 2,254	$ (56)	$ -	$ -
	Adjustments to taxable income:										
11	Book Average net salvage	12,529	12,529	-	-	-	-	-	-	-	-
12	Adj. of book depreciation to tax basis (B)	$ 20,282	$ 19,552	$ -	$ -	$ -	$ 730	$ -	$ -	$ -	$ -
13	Tax cost of removal/salvage	(6,080)	(6,080)	-	-	-	-	-	-	-	-
14	Adjust cash pension	14,046	14,046	-	-	-	-	-	-	-	-
15	Net adjustment	40,777	40,047	-	-	-	730	-	-	-	-
16	Income subject to state income tax	61,102	61,068	(3,375)	(960)	-	2,171	2,254	(56)	-	-
17	State income tax @ 9.99%	$ 6,104	$ 6,101	$ (337)	$ (96)	$ -	$ 217	$ 225	$ (6)	$ -	$ -
18	Taxes as budgeted	-	-	-	-	-	-	-	-	-	-
19	Adjustment to state income tax	$ 6,104	$ 6,101	$ (337)	$ (96)	$ -	$ 217	$ 225	$ (6)	$ -	$ -
20	Income subject to federal income tax	$ 54,998	$ 54,967	$ (3,038)	$ (864)	$ -	$ 1,955	$ 2,029	$ (50)	$ -	$ -
21	Federal income tax @ 35%	$ 19,249	$ 19,239	$ (1,063)	$ (302)	$ -	$ 684	$ 710	$ (18)	$ -	$ -
22	Taxes as budgeted	39,423	39,423	-	-	-	-	-	-	-	-
23	Adjustment to federal income tax	$ (20,174)	$ (20,184)	$ (1,063)	$ (302)	$ -	$ 684	$ 710	$ (18)	$ -	$ -
	(A) Computation of Interest charges										
	Total rate base	$ 1,412,965	$ 1,384,856	$ -	$ -	$ -	$ 28,109	$ -	$ -	$ -	$ -
	Debt ratio	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%
	Cost of debt	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%
	Interest expense	$ 36,822	$ 36,089	$ -	$ -	$ -	$ 733	$ -	$ -	$ -	$ -
	(B) Adjustment of book depreciation to tax basis:										
	Tax depreciation	43,357	40,646	-	-	-	2,711	-	-	-	-
	Book depreciation	63,640	60,199	-	-	-	3,441	-	-	-	-
	Depreciation adjustment	(20,282)	(19,552)	-	-	-	(730)	-	-	-	-

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalization Adjustment No. 11
$000

Computation of Federal & State Income Taxes - Normalized

To (1) split the tax depreciation into cost of removal, smart meter, and distribution components, and (2) calculate the jurisdictional allocation.

Line No.	Description	Amount (1)	(2)	(3)
1	Tax depreciation expense per budget (Exhibit RAD-33)	$ 62,848		
2	Cost of removal / salvage in tax depreciation	7,825	77.70%	$ 6,080
3	Smart meter tax depreciation	2,711	100.00%	2,711
4	Distribution tax depreciation	$ 52,312	77.70%	40,646
5	Total tax Depreciation			$ 43,357

Metropolitan Edison Company
Normalization Adjustment No. 12
$000

Adjustment of Provision for Deferred Income Taxes

This adjustment to the Provision for Deferred Income Taxes reflects the adjustment of Federal deferrals to reflect year-end plant. All state deferred taxes associated with liberalized depreciation have been eliminated.

Line No.	Description	Provision for Deferred Taxes - Net	
		Federal	State
		(1)	(2)
1	Deferred taxes per budget, 12 months ending 4/30/2016	$ 6,297	$ -
2	Deferred taxes - liberalized depreciation (Exhibit RAD-41, page 19)	4,630	-
3	Jurisdictional allocation factor	77.70%	77.70%
4	Jurisdictional deferred taxes - liberalized depreciation (Line 2 X Line 3)	3,598	-
5	Adjustment to deferred tax expense (Line 4 - Line 1)	(2,699)	-
6	Deferred tax expense per budget for the 12 months ending 4/30/2016, as adjusted	$ 3,598	$ -

Metropolitan Edison Company
Normalization Adjustment No. 13
$000

Adjustment of Investment Tax Credit

This adjustment eliminates the non-jurisdictional portion of investment tax credit adjustments.

Line No.	Description	Amount (1)	Amount (2)
1	Investment tax credit adjustments per budget, 12 months ending 4/30/2016		$ (364)
2	Jurisdictional allocation factor	77.70%	
3	Jurisdictional investment tax credit	$ (283)	
4	Adjustment to investment tax credit expense (Line 3 - Line 1)		81
5	Adjustment to investment tax credit expense per budget for the 12 months ending 4/30/2016, as adjusted		$ (283)

METROPOLITAN EDISON COMPANY
Rate Base At Original Cost
Normalized To Year-End Conditions at March 31, 2015
($000)

Line No.	Description	Per Budget	Adjustments and Normalizations	Adj No.	Total	Pa Juridictional Normalized Rate Base: Distribution	Pa Juridictional Normalized Rate Base: Smart Meter Costs	Pa Juridictional Normalized Rate Base: PA Jurisdictional Total
		(1)	(2)		(3)	(4)	(5)	(6) = (4) + (5)
	Electric Plant:							
1	Plant in service	$ 2,818,193	$ (645,740)	1	$ 2,172,453	$ 2,161,696	$ 10,757	$ 2,172,453
2	Plant held for future use	596	(596)	2	-	-	-	-
3	Construction work in progress - pollution control and safety	-	-		-	-	-	-
		-	-		-	-	-	-
4	Total electric plant	$ 2,818,789	$ (646,336)		$ 2,172,453	$ 2,161,696	$ 10,757	$ 2,172,453
	Depreciation & Amortization Reserve:							
5	Plant in service	$ 1,001,528	$ (295,475)	3	$ 706,053	$ 705,566	$ 487	$ 706,053
6	Plant held for future use	-	-		-	-	-	-
7	Total depreciation & amortization reserve	$ 1,001,528	$ (295,475)		$ 706,053	$ 705,566	$ 487	$ 706,053
8	Net Electric Plant	$ 1,817,261	$ (350,861)		$ 1,466,400	$ 1,456,130	$ 10,270	$ 1,466,400
	Additions:							
9	Cash working capital	$ -	$ 147,828	4	$ 147,828	$ 147,828	$ -	$ 147,828
10	M&S inventories	-	14,493	5	14,493	14,493	-	14,493
11	Deferred storm damage	-	64,964	6	64,964	64,964		64,964
12	Legacy meters	-	55,698	7	55,698	55,698	-	55,698
13	Total additions	$ -	$ 282,983		$ 282,983	$ 282,983	$ -	$ 282,983
	Deductions:							
14	Customer deposits	$ 20,925	$ -		$ 20,925	$ 20,925	$ -	$ 20,925
15	Customer advances for construction	19	-		19	19	-	19
16	Accum. Deferred income taxes - Liberalized depreciation	489,924	(132,620)	8	357,304	356,703	601	357,304
17	Operating reserves (net of taxes)	653	(146)	9	508	508	-	508
18	Total deductions	$ 511,521	$ (132,766)		$ 378,756	$ 378,155	$ 601	$ 378,756
19	Total Rate Base	$ 1,305,740	$ 64,888		$ 1,370,628	$ 1,360,959	$ 9,669	$ 1,370,628
20	Pro forma return at present rates (PA Distribution)	$ 28,742	Dollars					
21		2.10%	Percent					
22	Pro forma return at proposed rates (PA Distribution)	$ 110,373	Dollars					
23		8.05%	Percent					

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 1
($000)

Adjustment of Electric Plant in Service

To adjust the budgeted gross plant in service to (1) eliminate the Asset Retirement Cost ("ARC"). An asset retirement cost ("ARC") increases the carrying amount of a long-lived asset when a liability for an asset retirement obligation ("ARO") is recognized. The ARC is depreciated over the life of the asset. The ARC and related reserve are excluded from Rate Base, while the associated depreciation expense is excluded from the Income Statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18 Asset retirement obligations; (2) remove FERC Transmission Plant which is non-jurisdictional; (3) remove an allocated portion of Intangible Plant that supports FERC Transmission Plant; (4) remove an allocated portion of General Plant that supports FERC Transmission Plant; and (5) remove legacy meters as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Adjustments	Plant in Service	Cross Reference
		(1)	(2)	(3)
1	Budgeted Plant in Service at March 31, 2015		$ 2,818,193	Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2
	Normalizing adjustments:			
2	Eliminate ARC	$ (95,358)		Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2
3	Remove FERC Transmission Plant	(433,209)		Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2
4	Remove allocated portion of Intangible Plant associated with FERC Transmission Plant	(6,968)		Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2
5	Remove allocated portion of General Plant associated with FERC Transmission Plant	(43,410)		Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2
6	Remove legacy meters	(66,795)		Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2
7	Normalization adjustment		(645,740)	
8	Plant in Service at 3/31/2015, as adjusted		$ 2,172,453	Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 2
($000)

Adjustment of Plant Held for Future Use

To adjust Plant Held for Future Use. As an alternative to rate base treatment, the Company is requesting the allowance of deferred carrying charges on any current or future investments in Plant Held for Future Use with definitive plans of utilization within a ten-year period. This is consistent with long-standing Commission policy.

Line No.		Amount (1)
1	Per budget Plant Held for Future Use at 3/31/2015	$ 596
2	Eliminate Plant Held for Future Use	(596)
3	Plant Held for Future Use at 3/31/2015, as adjusted	$ -

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 3
($000)

Adjustment of Depreciation Reserves - Plant In Service

To adjust the budgeted plant in service depreciation reserves to (1) eliminate the Asset Retirement Cost ("ARC") reserves. An asset retirement cost ("ARC") increases the carrying amount of a long-lived asset when a liability for an asset retirement obligation ("ARO") is recognized. The ARC is depreciated over the life of the asset. The ARC and related reserve are excluded from Rate Base, while the associated depreciation expense is excluded from the Income Statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18 Asset retirement obligations; (2) remove FERC Transmission Plant reserves which are non-jurisdictional; (3) remove an allocated portion of Intangible Plant reserves that support FERC Transmission Plant; (4) remove an allocated portion of General Plant reserves that support FERC Transmission Plant; (5) and remove legacy meters as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Adjustments	Depreciation Reserves Plant in Service	Cross Reference
		(1)	(2)	(3)
1	Plant in Service depreciation reserves at 3/31/2015		$ 1,001,528	Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
	Normalizing adjustments:			
2	Eliminate ARC	$ (95,343)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
3	Remove FERC Transmission Plant	(151,084)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
4	Remove allocated portion of Intangible Plant associated with FERC Transmission Plant	(5,489)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
5	Remove allocated portion of General Plant associated with FERCTransmission Plant	(28,832)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
6	Legacy meters	(14,728)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
7	Normalization Adjustment		(295,475)	
8	Plant in Service depreciation reserves at 3/31/2015, as adjusted		$ 706,053	Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 4
($000)

Adjustment of Cash Working Capital

To recognize cash working capital at year-end level. This adjustment is supported by Ms. P. M. Larkin.

Line No.		Cash Working Capital (1)	Cash Working Capital (2)
1	Cash working capital per budget at 3/31/2015		$ -
	Normalizing adjustment:		
2	Cash working capital normalized to year-end (Exhibit PML-1)	$ 147,828	
3	Cash working capital per budget	-	
4	Normalization Adjustment		147,828
5	Cash working capital at 3/31/2015, as adjusted		$ 147,828

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 5
($000)

Adjustment of Material and Supplies Inventories

To recognize the Company's distribution portion of FE Service material and supplies ("M&S") inventory levels projected at 3/31/2015

Line No.		M&S Inventories (1)	M&S Inventories (2)
1	M&S Inventory per budget at 3/31/2015		$ -
	Normalizing adjustment:		
2	Distribution component of projected FE Service M&S Inventory allocated to Met-Ed at 3/31/2015 (Exhibit RAD-13)	$ 14,493	
3	M&S Inventory per budget at 3/31/2015	-	
4	Normalization Adjustment		14,493
5	M&S inventory at 3/31/2015, as adjusted		$ 14,493

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 6
($000)

Adjustment of Deferred Storm Damage Expenses

To include in rate base the deferred storm damage balances for Winter Storm Nika, approved at Docket No. P-2014-2412229, Hurricane Sandy, approved at Docket No. P-2013-2351260, and distribution non-capital storm expenses that exceeded 125% of storm costs included in base rates between the period of February 25, 2011 through September 30, 2012 as a result of the FirstEnergy and Allegheny Merger approved at Docket Nos. A-2010-2176520 and A-2010-2176732, including but not limited to Hurricane Irene, the October 2011 snowstorm, and Tropical Storm Lee.

Line No.		Storms	
		(1)	(2)
1	Unamortized storm deferral expense per budget at 3/31/2015		$ -
2	Deferred Nika storm damage	13,327	
3	Deferred Sandy storm damage	21,497	
4	Merger storm damage deferral	30,140	
5	Normalization less storm per budget Adjustment (Lines 2 + 3 + 4)		64,964
6	Storm Expense at 3/31/2015 as adjusted		$ 64,964

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 7
($000)

Adjustment to Include Legacy Meters in Regulatory Asset

To include legacy meters in a regulatory asset as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Legacy Meters (1)	Legacy Meters (2)
1	Net legacy meters in regulatory asset		$ -
2	Legacy meters per budget at 3/31/2015	$ 66,795	
3	Net estimated cost of removal and salvage	3,631	
4	Depreciation reserve per budget at 3/31/2015	(14,728)	
5	Net legacy meters normalizing adjustment (Lines 2 + 3 + 4)		55,698
6	Net legacy meters in regulatory asset as adjusted at 3/31/2015		$ 55,698

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 8
($000)

Adjustment of Accumulated Deferred Income Taxes - Liberalized Depreciation

This adjustment adjusts the budgeted deferred tax balances for liberalized depreciation (excluding the impact of SFAS No. 109 deferrals) to (1) eliminate the deferred income taxes - liberalized depreciation balances associated with TMI-2; (2) eliminate deferred income taxes - liberalized depreciation associated with other generation; (3) eliminate other excludable items (capital leases); (4) eliminate remaining state deferred taxes - liberalized depreciation balances including the federal benefit of those taxes; and (5) eliminate an allocated portion of the remaining federal deferred income taxes - liberalized depreciation balance associated with FERC Transmission Plant.

Line No.		Adjustments (1)	Accum Reserve for Deferred Taxes - Liberalized Depreciation (2)
1	Deferred taxes per budget - liberalized depreciation at 3/31/2015		$ 489,924
	Normalizing adjustments:		
2	Eliminate deferred income taxes - liberalized depreciation associated with TMI-2 (federal and state)	$ 2,840	
3	Eliminate deferred income taxes - liberalized depreciation associated with other generation (federal and state)	(95)	
4	Eliminate other excludable items - capital leases (federal and state)	(17,014)	
5	Eliminate remaining state deferred taxes - liberalized depreciation including the federal benefit of those taxes	(15,804)	
6	Eliminate an allocated portion of the remaining federal deferred income taxes - liberalized depreciation associated with FERC Transmission Plant	(102,547)	
7	Normalization Adjustment		(132,620)
8	Deferred taxes - liberalized depreciation at 3/31/2015, as adjusted		$ 357,304

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 9
($000)

Adjustment of Operating Reserves

To adjust operating reserves (net of accumulated deferred income taxes) to eliminate an allocated portion associated with FERC Transmission operations.

Line No.		Amount
1	Operating reserves, net of taxes, per budget at 3/31/2015	$ 653
2	Eliminate portion of operating reserves associated with FERC Transmission operations	(146)
3	Operating reserves, net of taxes at 3/31/2015, as adjusted	$ 508

METROPOLITAN EDISON COMPANY

Rate of Return at March 31, 2015
($000)

Line No.	Description	Exhibit SRS-24 Capital Amounts (1)	Capital Ratios (2)	Cost Rate (3)	Weighted Cost Rate (4) = (2) X (3)
1	Total long-term debt	$ 849,707	50.04%	5.21%	2.61%
2	Total preferred stock	-	0.00%	0.00%	0.00%
3	Total Common Equity	848,489	49.96%	10.90%	5.44%
4	Total Capitalization	$ 1,698,196	100.00%		8.05%

Metropolitan Edison Company
Statement of Operating Income, 12 Months Ending March 31, 2015, Normalized and Adjusted
to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Per Budget	Normalizations & Adjustments	Adj. No.	Budget as Adjusted	Distribution	Normalized PaPUC Jurisdictional: Riders: Price to Compare	Universal Service	Energy Efficiency	Smart Meters	Default Service Support	Solar	NUG	Storm	PaPUC Total Distribution
		(1)	(2)		(3)=(1)+(2)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13) = (4) + (8)
	Operating revenues														
1	Retail sales	$ 675,063	$ (32)	1	$ 675,031	$ 249,195	$ 313,070	$ 21,501	$ 25,419	$ 13,760	$ 39,274	$ 3,060	$ 9,752	$ -	$ 262,955
2	STAS revenue	-	-	2	-	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	21,076	-		21,076	-	20,983	-	93	-	-	-	-	-	-
4	Other operating revenue	72,494	(55,476)	3	17,017	18,593	(1,576)	-	-	-	-	-	-	-	18,593
5	Total operating revenue	768,633	(55,508)		713,124	267,788	332,477	21,501	25,512	13,760	39,274	3,060	9,752	-	281,548
	Operating expenses														
6	Price to Compare	322,385	-		322,385	-	320,256	-	-	-	-	2,129	-	-	-
7	Distribution	53,448	(8,202)	4	45,246	34,545	-		-	-	10,700	-	-	-	34,545
8	Customer accounts	25,286	1,528	5	26,814	18,705	-	-	-	-	8,109	-	-	-	18,705
9	Customer service & info	44,208	50	6	44,258	18,894	-	25,062	-	-	302	-	-	-	18,894
10	Admin & gen expense	37,806	18,217	7	56,023	19,902	-	-	24,389	11,732	-	-	-	-	31,634
11	Depreciation - accrual	59,573	11,245	8	70,818	69,469	-	-	-	1,349	-	-	-	-	70,818
12	Amortization & Accretion	13,023	22,344	9	35,367	21,655	(5,713)	(4,312)	(377)	(1,066)	15,233	770	9,177	-	20,589
13	Taxes other than income	46,882	(959)	10	45,923	20,798	18,471	1,269	1,500	812	2,317	181	575	-	21,610
14	Operating expense before tax	602,612	44,223		646,835	203,970	333,014	22,019	25,512	12,827	36,662	3,080	9,752	-	216,796
15	Operating income before incom	166,021	(99,732)		66,289	63,818	(537)	(518)	-	934	2,612	(19)	-	-	64,752
	Income taxes														
16	Federal income tax - current	25,303	(306)	11	24,997	24,079	(169)	(163)	-	434	823	(6)	-	-	24,513
17	State income tax - current	-	7,927	11	7,927	7,636	(54)	(52)	-	138	261	(2)	-	-	7,773
18	Deferred income tax - federal	27,321	(17,684)	12	9,637	9,426	-	-	-	211	-	-	-	-	9,637
19	Deferred income tax - state	-	-	12	-	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	(364)	(283)	13	(647)	(647)	-	-	-	-	-	-	-	-	(647)
21	Total tax expense	52,260	(10,346)		41,914	40,493	(223)	(215)	-	783	1,084	(8)	-	-	41,276
22	Total operating expenses	654,871	33,877		688,749	244,463	332,791	21,804	25,512	13,609	37,745	3,072	9,752	-	258,072
23	**Operating income**	$ 113,762	$ (89,386)		$ 24,375	$ 23,325	$ (314)	$ (303)	$ -	$ 151	$ 1,528	$ (11)	$ -	$ -	$ 23,476

Metropolitan Edison Company
Statement of Operating Income, 12 Months Ending March 31, 2015, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Distribution	Riders: Price to Compare	Riders: Universal Service	Riders: Energy Efficiency	Riders: Smart Meters	Riders: Default Service Support	Riders: Solar	Riders: NUG	Riders: Storm	PaPUC Total Distribution
		(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23) = (14) + (18)
	Operating revenues										
1	Retail sales	$ 156,698	$ -	$ -	$ -	$ 1,140	$ -	$ -	$ -	$ -	$ 157,838
2	STAS revenue	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	-	-	-	-	-	-	-	-	-	-
4	Other operating revenue	-	-	-	-	-	-	-	-	-	-
5	Total operating revenue	156,698	-	-	-	1,140	-	-	-	-	157,838
	Operating expenses										
6	Price to Compare	-	-	-	-	-	-	-	-	-	-
7	Distribution	-	-	-	-	-	-	-	-	-	-
8	Customer accounts	-	-	-	-	-	-	-	-	-	-
9	Customer service & info	-	-	-	-	-	-	-	-	-	-
10	Admin & gen expense	-	-	-	-	-	-	-	-	-	-
11	Depreciation - accrual	-	-	-	-	-	-	-	-	-	-
12	Amortization	-	-	-	-	-	-	-	-	-	-
13	Taxes other than income	9,245	-	-	-	67	-	-	-	-	9,312
14	Operating expense before tax	9,245	-	-	-	67	-	-	-	-	9,312
15	Operating income before incom	147,453	-	-	-	1,072	-	-	-	-	148,525
	Income taxes										
16	Federal income tax - current	46,453	-	-	-	338	-	-	-	-	46,791
17	State income tax - current	14,731	-	-	-	107	-	-	-	-	14,838
18	Deferred income tax - federal	-	-	-	-	-	-	-	-	-	-
19	Deferred income tax - state	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	-	-	-	-	-	-	-	-	-	-
21	Total tax expense	61,183	-	-	-	445	-	-	-	-	61,628
22	Total operating expenses	70,428	-	-	-	512	-	-	-	-	70,941
23	**Operating income**	$ 86,269	$ -	$ -	$ -	$ 627	$ -	$ -	$ -	$ -	$ 86,897

Metropolitan Edison Company
Statement of operating Income, 12 Months Ending March 31, 2015, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Distribution	Riders: Price to Compare	Riders: Universal Service	Riders: Energy Efficiency	Riders: Smart Meters	Riders: Default Service Support	Riders: Solar	Riders: NUG	Riders: Storm	PaPUC Total Distribution
		(24) = (4) + (14)	(25)	(26)	(27)	(28) = (8) + 18)	(29)	(30)	(31)	(32)	(33)
	Operating revenues										
1	Retail sales	$ 405,893	$ 313,070	$ 21,501	$ 25,419	$ 14,900	$ 39,274	$ 3,060	$ 9,752	$ -	$ 420,793
2	STAS revenue	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	-	20,983	-	93	-	-	-	-	-	-
4	Other operating revenue	18,593	(1,576)	-	-	-	-	-	-	-	18,593
5	Total operating revenue	424,486	332,477	21,501	25,512	14,900	39,274	3,060	9,752	-	439,386
						-					
	Operating expenses					-					
6	Price to Compare	-	320,256	-	-	-	-	2,129	-	-	-
7	Distribution	34,545	-	-	-	-	10,700	-	-	-	34,545
8	Customer accounts	18,705	-	-	-	-	8,109	-	-	-	18,705
9	Customer service & info	18,894	-	25,062	-	-	302	-	-	-	18,894
10	Admin & gen expense	19,902	-	-	24,389	11,732	-	-	-	-	31,634
11	Depreciation - accrual	69,469	-	-	-	1,349	-	-	-	-	70,818
12	Amortization	21,655	(5,713)	(4,312)	(377)	(1,066)	15,233	770	9,177	-	20,589
13	Taxes other than income	30,043	18,471	1,269	1,500	879	2,317	181	575	-	30,923
14	Operating expense before tax	213,215	333,014	22,019	25,512	12,894	36,662	3,080	9,752	-	226,109
15	Operating income before tax	211,271	(537)	(518)	-	2,006	2,612	(19)	-	-	213,277
	Income taxes										
16	Federal income tax - current	70,531	(169)	(163)	-	772	823	(6)	-	-	71,303
17	State income tax - current	22,366	(54)	(52)	-	245	261	(2)	-	-	22,611
18	Deferred income tax - federal	9,426	-	-	-	211	-	-	-	-	9,637
19	Deferred income tax - state	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	(647)	-	-	-	-	-	-	-	-	(647)
21	Total tax expense	101,677	(223)	(215)	-	1,228	1,084	(8)	-	-	102,904
		-				-				-	
22	Total operating expenses	314,892	332,791	21,804	25,512	14,122	37,745	3,072	9,752	-	$ 329,013
		-									
23	**Operating income**	$ 109,594	$ (314)	$ (303)	$ -	$ 779	$ 1,528	$ (11)	$ -	$ -	$ 110,373
24	**Rate Base**	$ 1,360,959	-	$ -	$ -	$ 9,669	$ -	$ -	$ -	$ -	1,370,628
25	**Rate of Return overall**	8.05%				8.05%					8.05%
26	**Return on Equity**	10.90%				10.90%					10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Distribution
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 249,195	$ 156,698	$ 405,893
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	18,593	-	18,593
5	Total operating revenue	267,788	156,698	424,486
	Operating expenses			
6	PTC	-	-	-
7	Distribution	34,545	-	34,545
8	Customer accounts	18,705	-	18,705
9	Customer service & info	18,894	-	18,894
10	Admin & gen expense	19,902	-	19,902
11	Depreciation - accrual	69,469	-	69,469
12	Amortization	21,655	-	21,655
13	Taxes other than income	20,798	9,245	30,043
14	Operating expense before tax	203,970	9,245	213,215
15	Operating income before tax	63,818	147,453	211,271
	Income taxes			
16	Federal income tax - current	24,079	46,453	70,531
17	State income tax - current	7,636	14,731	22,366
18	Deferred income tax - federal	9,426	-	9,426
19	Deferred income tax - state	-	-	-
20	Investment tax credit	(647)	-	(647)
21	Total tax expense	40,493	61,183	101,677
22	Total operating expenses	244,463	70,428	314,892
23	**Operating income**	$ 23,325	$ 86,269	$ 109,594
24	**Rate Base**	1,360,959		1,360,959
25	**Rate of Return overall**	1.71%		8.05%
26	**Return on Equity**	-1.79%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Smart Meter
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 13,760	$ 1,140	$ 14,900
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	13,760	1,140	14,900
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	-	-	-
10	Admin & gen expense	11,732	-	11,732
11	Depreciation - accrual	1,349	-	1,349
12	Amortization	(1,066)	-	(1,066)
13	Taxes other than income	812	67	879
14	Operating expense before tax	12,827	67	12,894
15	Operating income before tax	934	1,072	2,006
	Income taxes			
16	Federal income tax - current	434	338	772
17	State income tax - current	138	107	245
18	Deferred income tax - federal	211	-	211
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	783	445	1,228
22	Total operating expenses	13,609	512	14,122
23	**Operating income**	$ 151	$ 627	$ 779
24	**Rate Base**	9,669		9,669
25	**Rate of Return overall**	1.56%		8.05%
26	**Return on Equity**	-2.09%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Total Distribution
$000

Line No.	Description	Budget as Adjusted	Revenue Adjustment Required	Allowable Revenue
		(1)	(2)	(3)
	Operating revenues			
1	Retail sales	$ 262,955	$ 157,838	$ 420,793
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	18,593	-	18,593
5	Total operating revenue	281,548	157,838	439,386
	Operating expenses			
6	PTC	-	-	-
7	Distribution	34,545	-	34,545
8	Customer accounts	18,705	-	18,705
9	Customer service & info	18,894	-	18,894
10	Admin & gen expense	31,634	-	31,634
11	Depreciation - accrual	70,818	-	70,818
12	Amortization	20,589	-	20,589
13	Taxes other than income	21,610	9,312	30,923
14	Operating expense before tax	216,796	9,312	226,109
15	Operating income before tax	64,752	148,525	213,277
	Income taxes			
16	Federal income tax - current	24,513	46,791	71,303
17	State income tax - current	7,773	14,838	22,611
18	Deferred income tax - federal	9,637	-	9,637
19	Deferred income tax - state	-	-	-
20	Investment tax credit	(647)	-	(647)
21	Total tax expense	41,276	61,628	102,904
22	Total operating expenses	258,072	70,941	329,013
23	**Operating income**	$ 23,476	$ 86,897	$ 110,373
24	**Rate Base**	1,370,628		1,370,628
25	**Rate of Return overall**	1.71%		8.05%
26	**Return on Equity**	-1.79%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Universal Service Cost Rider
$000

Line No.	Description	Budget as Adjusted	Revenue Adjustment Required	Allowable Revenue
		(1)	(2)	(3)
	Operating revenues			
1	Retail sales	$ 21,501	$ -	$ 21,501
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	21,501	-	21,501
	Operating expenses	-		
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	25,062	-	25,062
10	Admin & gen expense	-	-	-
11	Depreciation - accrual	-	-	-
12	Amortization	(4,312)	-	(4,312)
13	Taxes other than income	1,269	-	1,269
14	Operating expense before tax	22,019	-	22,019
15	Operating income before tax	(518)	-	(518)
	Income taxes			
16	Federal income tax - current	(163)	-	(163)
17	State income tax - current	(52)	-	(52)
18	Deferred income tax - federal	-	-	-
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	(215)	-	(215)
22	Total operating expenses	21,804	-	21,804
23	**Operating income**	$ (303)	$ -	$ (303)

Metropolitan Edison Company
Summary of Revenue Requirements
Storm Damage Rider
$000

Line No.	Description	Budget as Adjusted	Revenue Adjustment Required	Allowable Revenue
		(1)	(2)	(3)
	Operating revenues			
1	Retail sales	$ -	$ -	$ -
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	-	-	-
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	-	-	-
10	Admin & gen expense	-	-	-
11	Depreciation - accrual	-	-	-
12	Amortization	-	-	-
13	Taxes other than income	-	-	-
14	Operating expense before tax	-	-	-
15	Operating income before tax	-	-	-
	Income taxes			
16	Federal income tax - current	-	-	-
17	State income tax - current	-	-	-
18	Deferred income tax - federal	-	-	-
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	-	-	-
22	Total operating expenses	-	-	-
23	**Operating income**	$ -		$ -

Metropolitan Edison Company
Normalization Adjustment No. 1
$000

Adjustment of Base Operating Revenues

To adjust base operating revenues (1) for changes in the number of customers, (2) to roll in State Tax Adjustment Surcharge ("STAS") revenues into base rates, (3) to adjust for energy efficiency and behind the meter generation, (4) to adjust for other revenues and (5) to eliminate unbilled revenues. The adjustment for unbilled revenues is supported by Mr. R. A. D'Angelo. Adjustments (1) through (4) are supported by Mr. K. M. Siedt.

Line No.	Description	Amount (1)	Amount (2)
1	Base revenues per budget for the 12 months ending 3/31/15		$ 675,063
	Normalizing adjustments:		
2	Customers - increase to yr end level	$ 394	
	Specific adjustments		
3	Roll-in of STAS	-	
4	Adjust for Energy Efficiency and Behind the Meter Generation	(2,232)	
5	Adjust for Other Revenues	42	
6	Eliminate unbilled revenues	1,763	
7	Total	$ (427)	
8	Normalizing adjustment (Lines 2+7)		(32)
9	Base revenues per budget for the 12 months ending 3/31/2015, as adjusted		$ 675,031

Metropolitan Edison Company
Normalization Adjustment No. 2
$000

Adjustment of State Tax Adjustment Surcharge Revenues

To remove state tax adjustment surcharge ("STAS") revenues. Normalized STAS revenues are being rolled into base rates.

Line No.	Description	Amount (1)
1	STAS revenue per budget for the 12 months ending 3/31/2015	$ -
2	Eliminate per budget STAS	-
3	Other operating revenue per budget for the 12 months ending 3/31/2015, as adjusted	$ -

Metropolitan Edison Company
Normalization Adjustment No. 3
$000

Adjustment of Other Operating Revenues

To adjust other operating revenue to eliminate non-jurisdictional transmission revenues.

Line No.	Description	Amount (1)
1	Other operating revenue per budget for the 12 months ending 3/31/2015	$ 72,494
2	Eliminate non-jurisdictional transmission revenues	(55,476)
3	Other operating revenue per budget for the 12 months ending 3/31/2015, as adjusted	$ 17,017

Metropolitan Edison Company
Normalization Adjustment No. 4
$000

Adjustment of Distribution Expense

To adjust distribution payroll expense to reflect year end wage and employee levels, to adjust service company distribution payroll expense to reflect year end wage and employee levels, eliminate non-jurisdictional transmission expense and to include the distribution portion of the amortization of gains or losses to reacquired debt. The plant and labor allocation factors used in this normalization adjustment are supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	Amount (2)
1	Distribution expense per budget for the 12 months ending 3/31/2015		$ 53,448
2	Distribution payroll expense adjustment to reflect year end employee levels, and ongoing wage and salary rates, (Supporting Schedule No. 1, Line 14, Column 1)	$ 298	
3	Service Company Distribution payroll expense adjustment allocated to Met-Ed to reflect year end employee levels, and ongoing wage and salary rates (Supporting Schedule No. 1, Line 26, Column 1)	100	
4	Eliminate non-jurisdictional transmission expense	(8,911)	
5	Amortization of (gain) or loss on reacquired debt	$ 400	
6	Allocation ratio based on distribution plant	77.70%	
7	Distribution portion of (gain) or loss	$ 311	
8	Total normalizing adjustment (Lines 2 + 3 + 4 + 7)		(8,202)
9	Distribution expense per budget for the 12 months ending 3/31/2015, as adjusted		$ 45,246

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 4
($000)

Adjustment to Payroll Expense to Reflect Year End Employee Levels and Wage Rates

Line No.	Description		Amount (1)	Amount (2)
1	Total payroll per budget for the 12 months ending 3/31/2015 (Exhibit RAD-27)			$ 59,762
	Bargaining			
2	Straight time per budget for the 12 months ending 3/31/2015		$ 35,333	
3	Straight time 2.5% increase effective 5/1/2015 (Line 2 x 2.5%)		883	
	Non-Bargaining			
4	Straight time per budget for April 1, 2014 through August 31, 2014		6,252	
5	Straight time 3% increase effective 9/1/2014 (Line 4 x 3%)		188	
6	Straight time per budget for April 1, 2014 through February 28, 2015		14,030	
7	Straight time 3% increase effective 3/1/2015 (Line 6 x 3%)		421	
8	Total company payroll adjustment (Line 3 + Line 5 + Line 7)			1,492
9	O&M allocation %		39.67%	
10	O&M payroll adjustment (Line 8 X Line 9)		$ 592	
11	Total Payroll as adjusted (Line 1 + Line 8)			$ 61,254
	Allocation of payroll adjustment:			
12	Price to Compare	0.00%	$ -	
13	Transmission	8.91%	53	
14	Distribution	50.40%	298	
15	Customer accounts	17.72%	105	
16	Customer service	8.42%	50	
17	Administrative and general	14.55%	86	
18	Total	100%	$ 592	
	Service Company (Exhibit RAD-25)			
19	Straight time per budget for April 1, 2014 through August 31, 2014		$ 5,766	
20	Straight time 3% increase effective 9/1/2014 (Line 19 x 3%)		173	
21	Straight time per budget for April 1, 2014 through February 28, 2015		12,859	
22	Straight time 3% increase effective 3/1/2015 (Line 21 x 3%)		386	
23	Total Service Company payroll adjustment (Lines 20 + 22)		$ 559	
	Allocation of Service Company payroll adjustment (Exhibit RAD-25):			
24	Price to Compare	0.00%	$ -	
25	Transmission	6.74%	38	
26	Distribution	17.91%	100	
27	Customer accounting and Information	28.31%	158	
28	Administrative and general	47.04%	263	
29	Total	100%	$ 559	

Metropolitan Edison Company
Normalization Adjustment No. 5
$000

Adjustment of Customer Accounts Expense

To adjust customer account expense to reflect year end wage and employee levels, service company year end wage and employee levels, increased costs associated with added customers, and interest on customer deposits.

Line No.	Description	Amount (1)	Amount (2)
1	Customer Account expense per budget for the 12 months ending 3/31/2015		$ 25,286
2	Customer Account payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates (Normalizing Adjustment No. 4, Supporting Schedule No. 1, Line 15, Column 1)	$ 105	
3	Service Company customer account payroll expense adjustment allocated to Met-Ed to reflect year end employee levels and ongoing wage & salary rates (Normalizing Adjustment No. 4, Supporting Schedule No. 1, Line 27, Column 1)	158	
4	Increased O&M costs associated with increased number of customers in normalized revenue levels (Supporting Schedule 1, Line 10)	9	
5	Interest on customer deposits (Supporting Schedule 2, Line 3)	1,256	
6	Total normalizing adjustment (Lines 2 + 3 + 4 + 5)		1,528
7	Customer Account expense per budget for the 12 months ending 3/31/2015, as adjusted		$ 26,814

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 5
($000)

Adjustment of Other O&M Costs Associated with Serving New Customers

In association with the additional revenues from added customers reflected in Adjustment No. 1, there is also a cost associated with serving those customers. The Commission has previously recognized this and approved an adjustment to customer accounts expense for this increased cost. This cost is estimated by determining the ratio of non-payroll customer account expense to distribution revenues from customers and applying this ratio to the additional revenue received from increased customers. The distribution revenues are supported by Mr. K. M. Siedt.

Line No.	Description	Amount
		(1)
	Customer Account Expense Excluding Labor and Uncollectible	
1	Customer Account expense per budget for the 12 months ending 3/31/2015	$ 25,286
2	Less: uncollectible expense	(13,864)
3	Less: Labor expense	(5,879)
4	Customer Account expense excluding labor and uncollectible expense	$ 5,543
	Total Base Revenue	
5	Distribution revenues per budget	$ 250,990
6	Late payment charges per budget	3,229
7	Total	$ 254,219
8	Ratio of customer account expense to distribution revenue (Line 4 / Line 7)	2.18%
9	Revenue from added customers (Adjustment No. 1, Line 2)	$ 394
10	Additional expense from added customers (Line 8 X Line 9)	$ 9

Metropolitan Edison Company
Supporting Schedule No.2 to Normalizing Adjustment No. 5
($000)

Adjustment to Allow for Interest Expense on Customer Deposits

Customer deposits are included in rate base as a deduction, since these are funds supplied by customers to the company. Interest paid to customers on these deposits correspondingly has been recognized by the Commission as a expense when setting rates.

Line No.	Description	Amount (1)
1	Customer deposits included in rate base (Exhibit RAD-1, Column 1, Line 14	$ 20,925
2	Interest rate on deposits	6%
3	Interest expense on customer deposits	$ 1,256

Metropolitan Edison Company
Normalization Adjustment No. 6
$000

Adjustment of Customer Service and Information Expense

To adjust customer service and information expense to reflect year end wage and employee levels.

Line No.	Description	Amount (1)	Amount (2)
1	Customer Service expense per budget for the 12 months ending 3/31/2015		$ 44,208
2	Customer Service payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 16, Column 1)	$ 50	
3	Total normalizing adjustment		50
4	Customer Service expense per budget for the 12 months ending 3/31/2015, as adjusted		$ 44,258

Metropolitan Edison Company
Normalization Adjustment No. 7
$000

Adjustment of Administrative and General Expense

To adjust Administrative and General expenses to reflect year end wage and employee levels, service company year end wage and employee levels, OPEB expense at the service cost level, pension expense to the ten year cash level, employee benefits expenses at year end personnel and wage levels, the elimination of non-jurisdictional administrative and general expenses, normalization of rate case expenses, eliminate legacy meters in the budget, and include costs to update computer system to allow accelerated (3 day) switching from one supplier to another. Hillary Stewart supports the non-jurisdictional expense allocation factor.

Line No.	Description	Amount (1)	Amount (2)
1	Administrative & general expense per budget for the 12 months ending 3/31/2015		$ 37,806
2	Administrative & general expenses related to EE&C	$ (24,389)	
3	Administrative & general expenses related to Smart Meters	(11,732)	
4	Adjustment to administrative & general expenses	(36,121)	
5	Net administrative & general expenses related to distribution	1,685	
6	Administrative & general payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates, (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 17, Column 1)	$ 86	
7	Service Company Administrative & general payroll expense adjustment allocated to Met-Ed to reflect year end employee levels and ongoing wage & salary rates (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 28, Column 1)	263	
8	Adjust OPEB expense to service cost level (Normalization Adjustment No. 7, Supporting Schedule No. 1, Line 12, Col. 1)	5,796	
9	Adjust pension expense to ten year cash level (Supporting Schedule No. 2, Line 18, Column 3)	14,259	
10	Adjust employee benefit costs (Supporting Schedule No. 3, Line 8, Column 3)	345	
11	Subtotal of adjustments (Lines 6 + 7 + 8 + 9 + 10)		20,749
12	Administrative and general expense, adjusted	$ 22,434	
13	Non-jurisdictional expense allocation factor	10.43%	
14	Non-jurisdictional administrative and general expense		(2,340)
15	Rate case expenses to be incurred during current rate proceeding (Exhibit RAD-23)	$ 495	
16	Recovery period - years	2	
17	Annual amount (Line 15 / Line 16)	$ 248	
18	Less rate case expenses in budget	(750)	
19	Adjusted total		$ (502)
20	Less legacy meters from budget		(1)
21	Increase in O&M costs for accelerated (3 day) switching for customers moving to a new supplier (Exhibit RAD-64)		311
22	Total normalizing adjustment (Lines 11 + 14 + 19 + 20 + 21)		$ 18,217
23	Administrative and general expense per budget for the 12 months ending 3/31/2015, as adjusted		$ 56,023

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 7
$000

Adjustment for OPEB Expense

Budgeted OPEB expense consists of the current service cost, adjustments to prior years' service costs, and the financing component. This schedule adjusts the total budgeted expense amounts to the service cost. The service cost represents the actuarial present value of benefit liabilities accrued under the plan benefit formula for services rendered during the test year. Inclusion of the service cost in rates provides for recovery of the current cost of benefits earned by plan participants. Any excess or shortfall related to the expected return on plan assets are not included because their inclusion would artificially reduce or increase total costs and result in the recovery of more or less than the actual normal cost of service. The adjustment for OPEB expense to the current service cost amount was adopted by the Commission at Docket Nos. R-00061366 and R-00061367

Line No.	Description	O&M	Capital	Total
		(1)	(2)	(3)
1	O&M - Capital allocation ratios	39.67%	60.33%	100.00%
2	Company OPEB expense included in budget	$ (4,672)	$ (7,105)	$ (11,777)
3	FirstEnergy Service Corp. OPEB expense	$ (15,287)	$ (23,249)	$ (38,537)
4	Allocation ratio	5.54%	5.54%	5.54%
5	Allocated FirstEnergy Service Corp. OPEB expense included in budget (Line 3 X Line 4)	$ (847)	$ (1,288)	$ (2,135)
6	Total OPEB expense included in budget (Line 2 + Line 5)	$ (5,519)	$ (8,393)	$ (13,912)
7	Service cost for company OPEB expense	$ 258	$ 393	$ 651
8	Service cost for FirstEnergy Service Corp. OPEB expense	$ 335	$ 510	$ 845
9	Allocation ratio	5.54%	5.54%	5.54%
10	Allocated FirstEnergy Service Corp. service cost (Line 8 X Line 9)	$ 19	$ 28	$ 47
11	Total OPEB service cost (Lines 7 + 10)	$ 277	$ 421	$ 698
12	Adjustment to set OPEB expense at ongoing service cost level (Lines 11 - 6)	$ 5,796	$ 8,814	$ 14,610

Metropolitan Edison Company
Supporting Schedule No. 2 to Normalizing Adjustment No. 7
$000

Adjustment for Pension Expense

To adjust budget pension expense to a ten year historical average level of actual cash contributions under the methodolc

Line No.	Description	Amount (1) Total	(2) O&M %	(3) O&M
	Company Cash Contributions			
1	2004 Cash Pension Contribution	$ 38,823	56.52%	$ 21,943
2	2005 Cash Pension Contribution	35,912	56.52%	20,297
3	2007 Cash Pension Contribution	11,012	55.42%	6,103
4	2009 Cash Pension Contribution	123,521	50.49%	62,366
5	2011 Cash Pension Contribution	35,000	45.09%	15,782
6	Total Company Cash Pension Contributions	$ 244,268		$ 126,490
	FirstEnergy Service Company Cash Contributions			
7	2004 Pension Contribution	$ 91,633		
8	2004 Company Allocation Factor	8.91%		
9	2004 Service Company Pension Contribution allocated to the Company	$ 8,165	56.52%	$ 4,615
10	2007 Pension Contribution	$ 27,468		
11	2007 Company Allocation Factor	11.29%		
12	2007 Service Company Pension Contribution allocated to the Company	$ 3,101	55.42%	1,719
13	Total FirstEnergy Service Company Cash Pension Contributions allocated to the Company (Line 9 + Line 12)	$ 11,266		$ 6,333
14	Total Pension cash contributions (Line 6 + Line 13)	$ 255,534		$ 132,824
15	Average	10		10
16	Pension expense cash contribution, amortized over 10 years	$ 25,553		$ 13,282
17	O&M Pension Expense included in budget			(977)
18	Adjustment to Pension Expense (Line 16 - Line 17)			$ 14,259

Metropolitan Edison Company
Supporting Schedule No. 3 to Normalizing Adjustment No. 7
$000

Adjustment to Employee Benefit Expense to Reflect Year End Employee Levels and Ongoing Wage Rates

Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 10 increases the O&M payroll expense. Associated with that increase are employee benefits charged to Administrative and General expense. This adjustment computes the added benefit costs on a normalized basis.

Employee benefits applicable to operating expenses:

Line No.		Effective Rate (a)	Payroll Adjustment		Benefit Adjustment
		(1)	(2)		(3) = (1) X (2)
1	Workers compensation	0.716%	$ 592	(b)	$ 4
2	Pension costs	40.873%	$ 592	(b)	242
3	OPEB costs	1.089%	$ 592	(b)	6
4	Life insurance	0.166%	$ 592	(b)	1
5	Medical insurance	9.081%	$ 592	(b)	54
6	Savings Plan	3.748%	$ 592	(b)	22
7	Other	2.651%	$ 592	(b)	16
8	Total increase due to payroll adjustment				$ 345

(a) Summary of effective employee benefit rates based on total payroll for the 12 months ending 3/31/15

	Total Amount	Total Payroll	Effective Rate
Workers compensation	$ 428	$ 59,762	0.716%
Pension costs - normalized basis	24,427	59,762	40.873%
OPEB costs - service cost	651	59,762	1.089%
Life Insurance (Exhibit RAD-27)	99	59,762	0.166%
Medical insurance	5,427	59,762	9.081%
Savings Plan	2,240	59,762	3.748%
Other	1,584	59,762	2.651%

(b) Adjustment No. 4, Supporting Schedule No. 1, Line 10.

Metropolitan Edison Company
Normalization Adjustment No. 8
$000

Adjustment of Depreciation Expense

To adjust budgeted depreciation expense to reflect average remaining life rates on adjusted rate base, to eliminate non-jurisdictional expense, and to adjust cost of removal/ salvage expense to a five year average amount, according to prior commission practice and the adjustment of legacy meters. The plant allocation factor used in this normalization adjustment are supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	(2)	(3)	(4)
1	Depreciation expense per budget for the 12 months ending 3/31/2015				$ 59,573
2	Cost of removal/salvage expense per budget for the 12 months ending 3/31/2015 (Exhibit RAD-30)		$ 4,453		
3	Depreciation accrual per budget (Line 1 - Line 2)		$ 55,120		
4	Jurisdictional depreciation expense accrual on adjusted rate base at average remaining life rates (Exhibit RAD-53, page 2)		47,150		
5	Adjustment for average remaining life accrual for jurisdictional plant, (Line 4 - Line 3).			(7,970)	
6	Cost of removal/salvage expense per budget for the 12 months ending 3/31/2015 (Exhibit RAD-30)		$ 4,453		
	Cost of removal and salvage (Exhibit RAD-30)				
7	4/1/2010 - 3/31/2011	$ 17,539			
8	4/1/2011 - 3/31/2012	7,101			
9	4/1/2012 - 3/31/2013	17,511			
10	4/1/2013 - 3/31/2014	28,248			
11	4/1/2014 - 3/31/2015	10,222			
12	Total	$ 80,620			
13	Five year average (Line 12 / 5)		$ 16,124		
14	Allocation ratio based on jurisdictional plant		77.70%		
15	Jurisdictional cost of removal/salvage expense to a jurisdictional five year average (Line 13 x Line 14)		$ 12,528		
16	Adjustment of jurisdictional cost of removal/salvage expense to a jurisdictional five year average (Line 15 - Line 6)			8,075	
17	Adjustment for acceleration of legacy meters (Adj. 8 Sched 1, Line 6)			11,140	
18	Total normalizing adjustment (Lines 5 + 16 + 17)				11,245
19	Depreciation expense per budget for the 12 months ending 3/31/2015, as adjusted				$ 70,818

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 8
$000

Adjustment for Acceleration for legacy meters

To accelerate recovery of legacy meters to fully recover all legacy meter costs over 5 years.

Line No.	Description	Amount (1)	Amount (2)
1	Legacy meters per budget for the 12 months ending 3/31/2015	$ 66,795	
2	Depreciation reserve per budget for the 12 months ending 3/31/2015	14,728	
3	Net legacy meters per budget for the 12 months ending 3/31/2015	$ 52,067	
4	Net estimated cost of removal and salvage	3,631	
5	Net legacy meters	$ 55,698	
6	Annual amortization over a 5 year amortization period		$ 11,140

Metropolitan Edison Company
Normalization Adjustment No. 9
$000

Adjustment of Amortization Expense

To include the amortization of deferred storm damage balances for Winter Storm Nika, approved at Docket No. P-2014-2412229, Hurricane Sandy, approved at Docket No. P-2013-2351260, and distribution non-capital storm expenses that exceeded 125% of storm costs included in base rates between the period of February 25, 2011 through September 30, 2012 as a result of the FirstEnergy and Allegheny Merger approved at Docket Nos. A-2010-2176520 and A-2010-2176732, including but not limited to Hurricane Irene, the October 2011 snowstorm, and Tropical Storm Lee. In addition, rate case expenses, legacy meters, and accretion expense are removed from the budget.

Line No.	Description	Amount (1)	Amount (2)	Amount (3)
1	Amortization expense per budget for the 12 months ending 3/31/2015			$ 13,023
2	Deferred Nika storm damage	$ 13,327		
3	Deferred Sandy storm damage	21,497		
4	Merger storm deferral	30,140		
5	Total deferred storms (Lines 2 + 3 + 4)	$ 64,964		
6	Amortized over 3 years	3		
7	Annual Amortization		$ 21,655	
8	Remove rate case expenses		750	
9	Remove legacy meters from budget		1	
10	Remove accretion expense		(62)	
11	Normalization adjustment (Lines 7 + 8 + 9 + 10)			22,344
12	Amortization expense per budget for the 12 months ending 3/31/2015			$ 35,367

Metropolitan Edison Company
Normalization Adjustment No. 10
$000

Adjustment of Taxes Other Than Income

To adjust gross receipts tax expense to reflect normalized sales revenues, to adjust payroll tax expenses for normalized payroll and employee expenses. The non-jurisdictional allocation factor is supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	Amount (2)	Amount (3)
1	Taxes Other Than Income per budget for the 12 months ending 3/31/2015			$ 46,882
2	Federal and State payroll taxes in budget	$ 4,523		
3	Non-jurisdictional percent	10.43%		
4	Eliminate non-jurisdictional payroll taxes		$ (472)	
5	Capital Stock Tax included in budget	$ 346		
6	PURTA tax in budget	1,954		
7	Real Estate tax in budget	130		
8	Total Other taxes	$ 2,430		
9	Non-jurisdictional percent	22.30%		
10	Eliminate non-jurisdictional taxes		(542)	
	Gross Receipts Tax			
11	Normalized sales revenues (Exhibit RAD-4, page 1, Col. 3)	$ 675,031		
12	Gross receipts tax @ 5.9%	39,827		
13	Gross receipts tax included in budget	39,817		
14	Adjustment for gross receipts tax at normalized revenue level (Line 12 - Line 13)		10	
15	Adjustment for payroll taxes on normalized payroll (Supporting Schedule No. 1, Line 8)		45	
16	Total normalizing adjustment (Lines 4+10+14+15)			(959)
17	Taxes other than income per budget for the 12 months ending 3/31/2015, as adjusted			$ 45,923

Metropolitan Edison Company
Supporting Schedule No.1 to Normalizing Adjustment No. 10
$000

Adjustment to Taxes Other Than Income to reflect changes in payroll taxes.

Normalization adjustments have been made to normalize O&M payroll expense. Associated with those payroll normalizations are changes in FICA tax amounts.

Line No.	Description	Amount (1)
1	Total payroll per budget for the 12 months ending 3/31/2015 (Normalization Adjustment No. 4, Schedule 1, Line 1, Col 2)	$ 59,762
2	Total payroll tax included in budget	4,523
3	Effective payroll tax rate (Line 2 / Line 1)	7.568%
4	Total payroll as adjusted (Normalization Adjustment No. 4, Schedule 1, Line 11, Col. 2)	$ 61,254
5	Payroll tax on normalized payroll (Line 3 x Line 4)	$ 4,636
6	Total Company payroll tax adjustment (Line 5 - Line 2)	$ 113
7	O&M Allocation percentage	39.67%
8	Adjustment for payroll tax (Line 6 x Line 7)	$ 45

Metropolitan Edison Company
Normalization Adjustment No. 11
$000

Computation of Federal & State Income Taxes - Normalized

Line No.	Description	Total Company Calculated Taxes (1)	PTC Calculated Taxes (2)	Distribution Calculated Taxes (3)	Universal Service Calculated Taxes (4)	Energy Efficiency Calculated Taxes (5)	Smart Meter Rider Calculated Taxes (6)	DSS Calculated Taxes (7)	Solar Calculated Taxes (8)	NUG Charge Calculated Taxes (9)	Storm Rider Calculated Taxes (10)
1	Total operating revenue	$ 713,124	$ 332,477	$ 267,788	$ 21,501	$ 25,512	$ 13,760	$ 39,274	$ 3,060	$ 9,752	$ -
2	Less: Total O& M Expense	494,727	320,256	92,048	25,062	24,389	11,732	19,111	2,129	$ -	$ -
3	Depreciation - accrual	58,290	-	56,941	-	-	1,349	-	-	-	-
4	Average net salvage	12,528	-	12,528	-	-	-	-	-	-	-
5	Amortization	35,367	(5,713)	21,655	(4,312)	(377)	(1,066)	15,233	770	9,177	-
6	Taxes other than income taxes	45,923	18,471	20,798	1,269	1,500	812	2,317	181	575	-
7	Total deductions	$ 646,835	$ 333,014	$ 203,970	$ 22,019	$ 25,512	$ 12,827	$ 36,662	$ 3,080	$ 9,752	$ -
8	Net operating income before income taxes	$ 66,289	$ (537)	$ 63,818	$ (518)	$ -	$ 934	$ 2,612	$ (19)	$ -	$ -
9	Less: Interest Charges (A)	35,733	-	35,481	-	-	252	-	-	-	-
10	Net income before income taxes	$ 30,556	$ (537)	$ 28,337	$ (518)	$ -	$ 682	$ 2,612	$ (19)	$ -	$ -
	Adjustments to taxable income:										
11	Book Average net salvage	12,528	-	12,528	-	-	-	-	-	-	-
12	Adj. of book depreciation to tax basis (B)	$ 28,474	$ -	$ 27,778	$ -	$ -	$ 696	$ -	$ -	$ -	$ -
13	Tax cost of removal/salvage	(6,472)	-	(6,472)	-	-	-	-	-	-	-
14	Adjust cash pension	14,259	-	14,259	-	-	-	-	-	-	-
15	Net adjustment	48,790	-	48,095	-	-	696	-	-	-	-
16	Income subject to state income tax	79,346	(537)	76,431	(518)	-	1,378	2,612	(19)	-	-
17	State income tax @ 9.99%	$ 7,927	$ (54)	$ 7,636	$ (52)	$ -	$ 138	$ 261	$ (2)	$ -	$ -
18	Taxes as budgeted	-	-	-	-	-	-	-	-	-	-
19	Adjustment to state income tax	$ 7,927	$ (54)	$ 7,636	$ (52)	$ -	$ 138	$ 261	$ (2)	$ -	$ -
20	Income subject to federal income tax	$ 71,420	$ (484)	$ 68,796	$ (466)	$ -	$ 1,240	$ 2,351	$ (18)	$ -	$ -
21	Federal income tax @ 35%	$ 24,997	$ (169)	$ 24,079	$ (163)	$ -	$ 434	$ 823	$ (6)	$ -	$ -
22	Taxes as budgeted	25,303	-	25,303	-	-	-	-	-	-	-
23	Adjustment to federal income tax	$ (306)	$ (169)	$ (1,224)	$ (163)	$ -	$ 434	$ 823	$ (6)	$ -	$ -
	(A) Computation of Interest charges										
	Total rate base	$ 1,370,628	$ -	$ 1,360,959	$ -	$ -	$ 9,669	$ -	$ -	$ -	$ -
	Debt ratio	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%
	Cost of debt	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%
	Interest expense	$ 35,733	$ -	$ 35,481	$ -	$ -	$ 252	$ -	$ -	$ -	$ -
	(B) Adjustment of book depreciation to tax basis:										
	Tax depreciation	29,815	-	29,162	-	-	653	-	-	-	-
	Book depreciation	58,290	-	56,941	-	-	1,349	-	-	-	-
	Depreciation adjustment	(28,474)	-	(27,778)	-	-	(696)	-	-	-	-

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalization Adjustment No. 11
$000

Computation of Federal & State Income Taxes - Normalized

To (1) split the tax depreciation into cost of removal, smart meter, and distribution components, and (2) calculate the jurisdictional allocation.

Line No.	Description		Amount (1)	Amount (2)
1	Tax depreciation expense per budget (Exhibit RAD-33)	$	46,514	
2	Cost of removal / salvage		8,329	77.70%
3	Smart meter tax depreciation		653	100.00%
4	Distribution tax depreciation		37,532	77.70%
5	Total tax depreciation			

Metropolitan Edison Company
Normalization Adjustment No. 12
$000

Adjustment of Provision for Deferred Income Taxes

This adjustment to the Provision for Deferred Income Taxes reflects (1) the adjustment of Federal deferrals to reflect year-end plant. All state deferred taxes associated with liberalized depreciation have been eliminated.

Line No.	Description	Provision for Deferred Taxes - Net	
		Federal	State
		(1)	(2)
1	Deferred taxes per budget, 12 months ending 3/31/2015	$ 27,321	$ -
2	Deferred taxes - liberalized depreciation (Exhibit RAD-41, page 20)	12,403	-
3	Jurisdictional allocation factor	77.70%	77.70%
4	Jurisdictional deferred taxes - liberalized depreciation (Line 2 x Line 3)	9,637	-
5	Adjustment to deferred tax expense (Line 4 - Line 1)	(17,684)	-
6	Deferred tax expense per budget for the 12 months ending 3/31/2015, as adjusted	$ 9,637	$ -

Metropolitan Edison Company
Normalization Adjustment No. 13
$000

Adjustment of Investment Tax Credit

This adjustment includes the investment tax credit and eliminates the non-jurisdictional portion of investment tax

Line No.	Description	Amount (1)	Amount (2)
1	Investment tax credit adjustments per budget, 12 months ending 3/31/2015		$ (364)
2	Jurisdictional allocation factor	77.70%	
3	Jurisdictional investment tax credit	$ (283)	
4	Adjustment to investment tax credit expense (Line 3 - Line 1)		81
5	Adjustment to investment tax credit expense per budget for the 12 months ending 3/31/2015, as adjusted		$ (283)

METROPOLITAN EDISON COMPANY
Rate Base At Original Cost
Normalized To Year-End Conditions at March 31, 2014
($000)

Line No.	Description	Per Budget	Adjustments and Normalizations	Adj No.	Total	Pa Jurisdictional Normalized Rate Base: Distribution	Smart Meter Costs	PA Jurisdictional Total
		(1)	(2)		(3)	(4)	(5)	(6) = (4) + (5)
	Electric Plant:							
1	Plant in service	$ 2,699,281	$ (608,677)	1	$ 2,090,604	$ 2,088,147	$ 2,457	$ 2,090,604
2	Plant held for future use	596	(596)	2	-	-	-	-
3	Construction work in progress - pollution control and safety	-	-		-	-	-	-
		-	-		-	-	-	-
4	Total electric plant	$ 2,699,877	$ (609,273)		$ 2,090,604	$ 2,088,147	$ 2,457	$ 2,090,604
	Depreciation & Amortization Reserve:							
5	Plant in Service	$ 959,316	$ (289,003)	3	$ 670,313	$ 670,177	$ 136	$ 670,313
6	Plant held for future use	-	-		-	-	-	-
7	Total depreciation & amortization reserve	$ 959,316	$ (289,003)		$ 670,313	$ 670,177	$ 136	$ 670,313
8	Net Electric Plant	$ 1,740,561	$ (320,270)		$ 1,420,291	$ 1,417,970	$ 2,321	$ 1,420,291
	Additions:							
9	Cash working capital	$ -	$ 147,828	4	$ 147,828	$ 147,828	$ -	$ 147,828
10	M&S inventories	-	14,493	5	14,493	14,493	-	14,493
11	Deferred storm damage	-	64,964	6	64,964	64,964	-	64,964
12	Legacy meters	-	58,341	7	58,341	58,341	-	58,341
13	Total additions	$ -	$ 285,627		$ 285,627	$ 285,627	$ -	$ 285,627
	Deductions:							
14	Customer deposits	$ 21,452	$ -		$ 21,452	$ 21,452	$ -	$ 21,452
15	Customer advances for construction	19	-		19	19	-	19
16	Accum. Deferred income taxes - Liberalized depreciation	478,696	(130,107)	8	348,589	347,991	598	348,589
17	Operating reserves (net of taxes)	653	(146)	9	508	508	-	508
18	Total deductions	$ 500,820	$ (130,253)		$ 370,568	$ 369,970	$ 598	$ 370,568
19	Total Rate Base	$ 1,239,741	$ 95,609		$ 1,335,350	$ 1,333,627	$ 1,723	$ 1,335,350
20	Pro forma return at present rates (PA Distribution)	$ 30,254	Dollars					
21		2.27%	Percent					
22	Pro forma return at proposed rates (PA Distribution)	$ 107,517	Dollars					
23		8.05%	Percent					

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 1
($000)

Adjustment of Electric Plant in Service

To adjust the budgeted gross plant in service to (1) eliminate the Asset Retirement Cost ("ARC"). An asset retirement cost ("ARC") increases the carrying amount of a long-lived asset when a liability for an asset retirement obligation ("ARO") is recognized. The ARC is depreciated over the life of the asset. The ARC and related reserve are excluded from Rate Base, while the associated depreciation expense is excluded from the Income Statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18 Asset retirement obligations; (2) remove FERC Transmission Plant which is non-jurisdictional; (3) remove an allocated portion of Intangible Plant that supports FERC Transmission Plant; (4) remove an allocated portion of General Plant that supports FERC Transmission Plant; and (5) remove legacy meters as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Adjustments	Plant in Service	Cross Reference
		(1)	(2)	(3)
1	Actual Plant in Service at March 31, 2014		$ 2,699,281	Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2
	Normalizing adjustments:			
2	Eliminate ARC	$ (95,358)		Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2
3	Remove FERC transmission plant	(397,455)		Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2
4	Remove allocated portion of Intangible Plant associated with FERC Transmission Plant	(6,478)		Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2
5	Remove allocated portion of General Plant associated with FERC Transmission Plant	(42,590)		Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2
6	Remove legacy meters	(66,795)		Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2
7	Normalization adjustment		(608,677)	
8	Plant in Service at 3/31/2014, as adjusted		$ 2,090,604	Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 2
($000)

Adjustment of Plant Held for Future Use

To adjust Plant Held for Future Use. As an alternative to rate base treatment, the Company is requesting the allowance of deferred carrying charges on any current or future investments in Plant Held for Future Use with definitive plans of utilization within a ten-year period. This is consistent with long-standing Commission policy.

Line No.		Amount (1)
1	Actual Plant Held for Future Use at 3/31/2014	$ 596
	Normalizing adjustment:	
2	Eliminate Plant Held for Future Use	(596)
3	Plant Held for Future Use at 3/31/2014, as adjusted	$ -

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 3
($000)

Adjustment of Depreciation Reserves - Plant In Service

To adjust the budgeted plant in service depreciation reserves to (1) eliminate the Asset Retirement Cost ("ARC") reserves. An asset retirement cost ("ARC") increases the carrying amount of a long-lived asset when a liability for an asset retirement obligation ("ARO") is recognized. The ARC is depreciated over the life of the asset. The ARC and related reserve are excluded from Rate Base, while the associated depreciation expense is excluded from the Income Statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18 Asset retirement obligations; (2) remove FERC Transmission Plant reserves which are non-jurisdictional; (3) remove an allocated portion of Intangible Plant reserves that support FERC Transmission Plant; (4) remove an allocated portion of General Plant reserves that support FERC Transmission Plant; (5) and remove legacy meters as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Adjustments	Depreciation Reserves Plant in Service	Cross Reference
		(1)	(2)	(3)
1	Actual plant in Service depreciation reserves at 3/31/2014		$ 959,316	Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
	Normalizing adjustments:			
2	Eliminate ARC	$ (95,342)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
3	Remove FERC Transmission Plant	(148,796)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
4	Remove allocated portion of Intangible Plant associated with FERC Transmission Plant	(5,092)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
5	Remove allocated portion of General Plant associated with FERCTransmission Plant	(27,687)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
6	Remove legacy meters	(12,085)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
7	Normalization Adjustment		(289,003)	
8	Plant in Service depreciation reserves at 3/31/2014, as adjusted		$ 670,313	

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 4
($000)

Adjustment of Cash Working Capital

To recognize cash working capital at year-end level. This adjustment is supported by Met-Ed's Witness Patricia M. Larkin.

Line No.		Cash Working Capital (1)	Cash Working Capital (2)
1	Cash working capital per books at 3/31/2014		$ -
	Normalizing adjustment:		
2	Cash working capital normalized to year-end (Exhibit PML-1)	$147,828	
3	Cash working capital per budget	-	
4	Normalization Adjustment		147,828
5	Cash working capital at 3/31/2014, as adjusted		$ 147,828

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 5
($000)

Adjustment of Material and Supplies Inventories

To recognize the Company's distribution portion of FE Service material and supplies ("M&S") inventory levels projected at 3/31/2014

Line No.		M&S Inventories (1)	M&S Inventories (2)
1	M&S Inventory per books at 3/31/2014		$ -
	Normalizing adjustment:		
2	Distribution component of projected FE Service M&S Inventory allocated to Met-Ed at 3/31/2014 (Exhibit RAD-13)	$ 14,493	
3	M&S Inventory per books at 3/31/2014	-	
4	Normalization Adjustment		14,493
5	M&S inventory at 3/31/2014, as adjusted		$ 14,493

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 6
($000)

Adjustment of Deferred Storm Damage Expenses

To include in rate base the deferred storm damage balances for Winter Storm Nika, approved at Docket No. P-2014-2412229, Hurricane Sandy, approved at Docket No. P-2013-2351260, and distribution non-capital storm expenses that exceeded 125% of storm costs included in base rates between the period of February 25, 2011 through September 30, 2012 as a result of the FirstEnergy and Allegheny Merger approved at Docket Nos. A-2010-2176520 and A-2010-2176732, including but not limited to Hurricane Irene, the October 2011 snowstorm, and Tropical Storm Lee.

Line No.		Storms	
		(1)	(2)
1	Unamortized storm deferral expense per books at 3/31/2014		$ -
2	Deferred Nika storm damage	13,327	
3	Deferred Sandy storm damage	21,497	
4	Merger storm damage deferral	30,140	
5	Normalization less storm per books Adjustment (Sum of Lines 2 + 3 + 4)		64,964
6	Storm Expense at 3/31/2014 as adjusted		$ 64,964

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 7
($000)

Adjustment to Include Legacy Meters in Regulatory Asset

To include legacy meters in a regulatory asset as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Legacy Meters (1)	Legacy Meters (2)
1	Net legacy meters in regulatory asset		$ -
2	Legacy meters per books at 3/31/2014	$ 66,795	
3	Net estimated cost of removal and salvage	3,631	
4	Depreciation reserve per books at 3/31/2014	(12,085)	
5	Net legacy meters normalizing adjustment (Lines 3 + 4 + 5)		58,341
6	Net legacy meters in regulatory asset as adjusted at 3/31/2014		$ 58,341

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 8
($000)

Adjustment of Accumulated Deferred Income Taxes - Liberalized Depreciation

This adjustment adjusts the budgeted deferred tax balances for liberalized depreciation (excluding the impact of SFAS No. 109 deferrals) to (1) eliminate the deferred income taxes - liberalized depreciation balances associated with TMI-2; (2) eliminate deferred income taxes - liberalized depreciation associated with other generation; (3) eliminate other excludable items (capital leases); (4) eliminate remaining state deferred taxes - liberalized depreciation balances including the federal benefit of those taxes; and (5) eliminate an allocated portion of the remaining federal deferred income taxes - liberalized depreciation balance associated with FERC Transmission Plant.

Line No.		Adjustments (1)	Accum Reserve for Deferred Taxes - Liberalized Depreciation (2)
1	Deferred taxes per books - liberalized depreciation at 3/31/2014		$ 478,696
	Normalizing adjustments:		
2	Eliminate deferred income taxes - liberalized depreciation associated with TMI-2 (federal and state)	$ 2,954	
3	Eliminate deferred income taxes - liberalized depreciation associated with other generation (federal and state)	(97)	
4	Eliminate other excludable items - capital leases (federal and state)	(17,014)	
5	Eliminate remaining state deferred taxes - liberalized depreciation including the federal benefit of those taxes	(15,904)	
6	Eliminate an allocated portion of the remaining federal deferred income taxes - liberalized depreciation associated with FERC Transmission Plant	(100,046)	
7	Normalization Adjustment		(130,107)
8	Deferred taxes - liberalized depreciation at 3/31/2014, as adjusted		$ 348,589

METROPOLITAN EDISON COMPANY

Normalization Adjustment No. 9
($000)

Adjustment of Operating Reserves

To adjust operating reserves (net of accumulated deferred income taxes) to eliminate an allocated portion associated with FERC Transmission operations.

Line No.		Amount
1	Operating reserves, net of taxes, per books at 3/31/2014	$ 653
2	Eliminate portion of operating reserves associated with FERC Transmission operations	(146)
3	Operating reserves, net of taxes at 3/31/2014, as adjusted	$ 508

METROPOLITAN EDISON COMPANY

Rate of Return at March 31, 2014
($000)

Line No.	Description	Exhibit SRS-24 Capital Amounts (1)	Capital Ratios (2)	Cost Rate (3)	Weighted Cost Rate (4) = (2) X (3)
1	Total long-term debt	$ 849,707	50.04%	5.21%	2.61%
2	Total preferred stock	-	0.00%	0.00%	0.00%
3	Total Common Equity	848,489	49.96%	10.90%	5.44%
4	Total Capitalization	$ 1,698,196	100.00%		8.05%

Metropolitan Edison Company
Statement of operating Income, 12 Months Ended March 31, 2014, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Per Budget	Normalizations & Adjustments	Adj. No.	Budget as Adjusted	Distribution	Normalized PaPUC Jurisdictional									
							Riders									
							Price to Compare	Universal Service	Energy Efficiency	Smart Meters	Default Service Support	Solar	NUG	Storm	CEC	PaPUC Distribution Total
		(1)	(2)		(3)=(1)+(2)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14) = (4) + (8)
	Operating revenues															
1	Retail sales	$ 741,232	$ (12,553)	1	$ 728,679	$ 245,159	$ 379,832	$ 28,882	$ 29,074	$ 7,831	$ 26,795	$ 2,651	$ 8,194	$ -	$ 261	$ 252,990
2	STAS revenue	(2,123)	2,123	2	-	-	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	26,062	-		26,062	15	25,590	-	457	-	-	-	-	-	-	15
4	Other operating revenue	70,921	(56,257)	3	14,664	19,328	(4,664)	-	-	-	-	-	-	-	-	19,328
5	Total operating revenue	836,092	(66,687)		769,405	264,502	400,758	28,882	29,531	7,831	26,795	2,651	8,194	-	261	272,333
	Operating expenses															
6	Price to Compare	382,374	-		382,374	52	380,800	-	-	-	-	1,522	-	-	-	52
7	Distribution	67,795	(6,717)	4	61,078	52,939			-	-	8,139	-	-	-	-	52,939
8	Customer accounts	24,842	1,536	5	26,378	18,793	-	-	-	-	7,585	-	-	-	-	18,793
9	Customer service & info	40,005	48	6	40,053	15,035	-	24,409	-	-	318	-	-	-	290	15,035
10	Admin & gen expense	6,525	31,487	7	38,012	9,349	-	-	21,093	7,570	-	-	-	-	-	16,919
11	Depreciation - accrual	58,193	10,824	8	69,017	68,888	-	-	-	129	-	-	-	-	-	69,017
12	Amortization & Accretion	12,250	21,597	9	33,847	11,795	(2,118)	3,164	6,659	(377)	6,232	938	7,573	-	(19)	11,418
13	Taxes other than income	50,525	(1,298)	10	49,227	20,663	22,492	1,749	1,779	443	1,305	156	621	-	20	21,106
14	Operating expense before tax	642,508	57,475		699,984	197,513	401,175	29,321	29,531	7,765	23,579	2,615	8,194	-	291	205,277
15	Operating income before incon	193,583	(124,162)		69,422	66,989	(416)	(440)	-	66	3,216	36	-	-	(30)	67,056
	Income taxes															
16	Federal income tax - current	28,956	(8,069)	11	20,887	20,294	(131)	(139)	-	(153)	1,013	11	-	-	(9)	20,141
17	State income tax - current	5,701	922	11	6,623	6,435	(42)	(44)	-	(48)	321	4	-	-	(3)	6,387
18	Deferred income tax - federal	(59,116)	69,697	12	10,581	10,372	-	-	-	209	-	-	-	-	-	10,581
19	Deferred income tax - state		-	12	-		-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	(397)	89	13	(308)	(308)	-	-	-	-	-	-	-	-	-	(308)
21	Total tax expense	(24,856)	62,639		37,783	36,794	(173)	(182)	-	8	1,335	15	-	-	(12)	36,801
22	Total operating expenses	617,652	120,114		737,767	234,306	401,002	29,139	29,531	7,772	24,913	2,630	8,194	-	279	242,079
23	**Operating income**	$ 218,439	$ (186,801)		$ 31,638	$ 30,196	$ (244)	$ (257)	$ -	$ 58	$ 1,882	$ 21	$ -	$ -	$ (17)	$ 30,254

Metropolitan Edison Company
Statement of operating Income, 12 Months Ended March 31, 2014, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Distribution	Riders: Price to Compare	Universal Service	Energy Efficiency	Smart Meters	Default Service Support	Solar	NUG	Storm	CEC	PaPUC Total
		(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25) = (15) + (19)
	Operating revenues											
1	Retail sales	$ 140,193	$ -	$ -	$ -	$ 146	$ -	$ -	$ -	$ -	$ -	$ 140,339
2	STAS revenue	-	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	-	-	-	-	-	-	-	-	-	-	-
4	Other operating revenue	-	-	-	-	-	-	-	-	-	-	-
5	Total operating revenue	140,193	-	-	-	146	-	-	-	-	-	140,339
												-
	Operating expenses											-
6	Price to Compare	-	-	-	-	-	-	-	-	-	-	-
7	Distribution	-	-	-	-	-	-	-	-	-	-	-
8	Customer accounts	-	-	-	-	-	-	-	-	-	-	-
9	Customer service & info	-	-	-	-	-	-	-	-	-	-	-
10	Admin & gen expense	-	-	-	-	-	-	-	-	-	-	-
11	Depreciation - accrual	-	-	-	-	-	-	-	-	-	-	-
12	Amortization	-	-	-	-	-	-	-	-	-	-	-
13	Taxes other than income	8,271	-	-	-	9	-	-	-	-	-	8,280
14	Operating expense before tax	8,271	-	-	-	9	-	-	-	-	-	8,280
												-
15	Operating income before incom	131,922	-	-	-	137	-	-	-	-	-	132,059
												-
	Income taxes											-
16	Federal income tax - current	41,560	-	-	-	43	-	-	-	-	-	41,603
17	State income tax - current	13,179	-	-	-	14	-	-	-	-	-	13,193
18	Deferred income tax - federal	-	-	-	-	-	-	-	-	-	-	-
19	Deferred income tax - state	-	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	-	-	-	-	-	-	-	-	-	-	-
21	Total tax expense	54,739	-	-	-	57	-	-	-	-	-	54,796
												-
22	Total operating expenses	63,010	-	-	-	66	-	-	-	-	-	63,076
												-
23	**Operating income**	$ 77,183	$ -	$ -	$ -	$ 80	$ -	$ -	$ -	$ -	$ -	$ 77,263

Metropolitan Edison Company
Statement of operating Income, 12 Months Ended March 31, 2014, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Distribution	Riders: Price to Compare	Riders: Universal Service	Riders: Energy Efficiency	Riders: Smart Meters	Riders: Default Service Support	Riders: Solar	Riders: NUG	Riders: Storm	CEC	PaPUC Total
		(26) = (4) + (15)	(27)	(28)	(29)	(30) = (8) + (19)	(31)	(32)	(33)	(34)	(35)	(36) = (26) + (30)
	Operating revenues											
1	Retail sales	$ 385,352	$ 379,832	$ 28,882	$ 29,074	$ 7,977	$ 26,795	$ 2,651	$ 8,194	$ -	$ 261	$ 393,329
2	STAS revenue	-	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	15	25,590	-	457	-	-	-	-	-	-	15
4	Other operating revenue	19,328	(4,664)	-	-	-	-	-	-	-	-	19,328
5	Total operating revenue	404,695	400,758	28,882	29,531	7,977	26,795	2,651	8,194	-	261	412,672
	Operating expenses											
6	Price to Compare	52	380,800	-	-	-	-	1,522	-	-	-	52
7	Distribution	52,939	-	-	-	-	8,139	-	-	-	-	52,939
8	Customer accounts	18,793	-	-	-	-	7,585	-	-	-	-	18,793
9	Customer service & info	15,035	-	24,409	-	-	318	-	-	-	290	15,035
10	Admin & gen expense	9,349	-	-	21,093	7,570	-	-	-	-	-	16,919
11	Depreciation - accrual	68,888	-	-	-	129	-	-	-	-	-	69,017
12	Amortization	11,795	(2,118)	3,164	6,659	(377)	6,232	938	7,573	-	(19)	11,418
13	Taxes other than income	28,935	22,492	1,749	1,779	451	1,305	156	621	-	20	29,386
14	Operating expense before tax	205,784	401,175	29,321	29,531	7,773	23,579	2,615	8,194	-	291	213,557
15	Operating income before tax	198,911	(416)	(440)	-	204	3,216	36	-	-	(30)	199,115
	Income taxes											
16	Federal income tax - current	61,854	(131)	(139)	-	(109)	1,013	11	-	-	(9)	61,745
17	State income tax - current	19,614	(42)	(44)	-	(35)	321	4	-	-	(3)	19,580
18	Deferred income tax - federal	10,372	-	-	-	209	-	-	-	-	-	10,581
19	Deferred income tax - state	-	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	(308)	-	-	-	-	-	-	-	-	-	(308)
21	Total tax expense	91,532	(173)	(182)	-	65	1,335	15	-	-	(12)	91,597
		-				-				-	-	-
22	Total operating expenses	297,317	401,002	29,139	29,531	7,838	24,913	2,630	8,194	-	279	305,155
		-										-
23	**Operating income**	$ 107,379	$ (244)	$ (257)	$ -	$ 139	$ 1,882	$ 21	$ -	$ 139	$ -	$ 107,517
24	**Rate Base**	$1,333,627	-	$ -	$ -	$ 1,723	$ -	$ -	$ -	$ -	$ -	1,335,350
							$ -					
25	**Rate of Return overall**	8.05%				8.05%						8.05%
26	**Return on Equity**	10.90%				10.90%						10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Distribution
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 245,159	$ 140,193	$ 385,352
2	STAS revenue	-	-	-
3	Sales for resale	15	-	15
4	Other operating revenue	19,328	-	19,328
5	Total operating revenue	264,502	140,193	404,695
	Operating expenses			
6	PTC	52	-	52
7	Distribution	52,939	-	52,939
8	Customer accounts	18,793	-	18,793
9	Customer service & info	15,035	-	15,035
10	Admin & gen expense	9,349	-	9,349
11	Depreciation - accrual	68,888	-	68,888
12	Amortization	11,795	-	11,795
13	Taxes other than income	20,663	8,271	28,935
14	Operating expense before tax	197,513	8,271	205,784
15	Operating income before tax	66,989	131,922	198,911
	Income taxes			
16	Federal income tax - current	20,294	41,560	61,854
17	State income tax - current	6,435	13,179	19,614
18	Deferred income tax - federal	10,372	-	10,372
19	Deferred income tax - state	-	-	-
20	Investment tax credit	(308)	-	(308)
21	Total tax expense	36,794	54,739	91,532
22	Total operating expenses	234,306	63,010	297,317
23	**Operating income**	$ 30,196	$ 77,183	$ 107,379
24	**Rate Base**	1,333,627		1,333,627
25	**Rate of Return overall**	2.37%		8.05%
26	**Return on Equity**	-0.68%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Smart Meter
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 7,831	$ 146	$ 7,977
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	7,831	146	7,977
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	-	-	-
10	Admin & gen expense	7,570	-	7,570
11	Depreciation - accrual	129	-	129
12	Amortization	(377)	-	(377)
13	Taxes other than income	443	9	451
14	Operating expense before tax	7,765	9	7,773
15	Operating income before tax	66	137	204
	Income taxes			
16	Federal income tax - current	(153)	43	(109)
17	State income tax - current	(48)	14	(35)
18	Deferred income tax - federal	209	-	209
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	8	57	65
22	Total operating expenses	7,772	66	7,838
23	**Operating income**	$ 58	$ 80	$ 139
24	**Rate Base**	1,723		1,723
25	**Rate of Return overall**	3.39%		8.05%
26	**Return on Equity**	1.56%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Total Distribution
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 252,990	$ 140,339	$ 393,329
2	STAS revenue	-	-	-
3	Sales for resale	15	-	15
4	Other operating revenue	19,328	-	19,328
5	Total operating revenue	272,333	140,339	412,672
	Operating expenses			
6	PTC	52	-	52
7	Distribution	52,939	-	52,939
8	Customer accounts	18,793	-	18,793
9	Customer service & info	15,035	-	15,035
10	Admin & gen expense	16,919	-	16,919
11	Depreciation - accrual	69,017	-	69,017
12	Amortization	11,418	-	11,418
13	Taxes other than income	21,106	8,280	29,386
14	Operating expense before tax	205,277	8,280	213,557
15	Operating income before tax	67,056	132,059	199,115
	Income taxes			
16	Federal income tax - current	20,141	41,603	61,745
17	State income tax - current	6,387	13,193	19,580
18	Deferred income tax - federal	10,581	-	10,581
19	Deferred income tax - state	-	-	-
20	Investment tax credit	(308)	-	(308)
21	Total tax expense	36,801	54,796	91,597
22	Total operating expenses	242,079	63,076	305,155
23	**Operating income**	$ 30,254	$ 77,263	$ 107,517
24	**Rate Base**	1,335,350		1,335,350
25	**Rate of Return overall**	2.27%		8.05%
26	**Return on Equity**	-0.68%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Universal Service Cost Rider
$000

Line No.	Description	Budget as Adjusted	Revenue Adjustment Required	Allowable Revenue
		(1)	(2)	(3)
	Operating revenues			
1	Retail sales	$ 28,882	$ -	$ 28,882
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	28,882	-	28,882
		-		
	Operating expenses	-		
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	24,409	-	24,409
10	Admin & gen expense	-	-	-
11	Depreciation - accrual	-	-	-
12	Amortization	3,164	-	3,164
13	Taxes other than income	1,749	-	1,749
14	Operating expense before tax	29,321	-	29,321
		-		
15	Operating income before tax	(440)	-	(440)
		-		
	Income taxes	-		
16	Federal income tax - current	(139)	-	(139)
17	State income tax - current	(44)	-	(44)
18	Deferred income tax - federal	-	-	-
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	(182)	-	(182)
		-		
22	Total operating expenses	29,139	-	29,139
23	**Operating income**	$ (257)	$ -	$ (257)

Metropolitan Edison Company
Summary of Revenue Requirements
Storm Damage Rider
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ -	$ -	$ -
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	-	-	-
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	-	-	-
10	Admin & gen expense	-	-	-
11	Depreciation - accrual	-	-	-
12	Amortization	-	-	-
13	Taxes other than income	-	-	-
14	Operating expense before tax	-	-	-
15	Operating income before tax	-	-	-
	Income taxes			
16	Federal income tax - current	-	-	-
17	State income tax - current	-	-	-
18	Deferred income tax - federal	-	-	-
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	-	-	-
22	Total operating expenses	-	-	-
23	**Operating income**	$ -		$ -

Metropolitan Edison Company
Normalization Adjustment No. 1
$000

Adjustment of Base Operating Revenues

To adjust base operating revenues (1) for changes in the number of customers, (2) to roll in State Tax Adjustment Surcharge ("STAS") revenues into base rates, (3) to adjust for energy efficiency and behind the meter generation, (4) to adjust for other revenues and (5) to eliminate unbilled revenues. The adjustment for unbilled revenues is supported by Mr. R. A. D'Angelo. Adjustments (1) through (4) are supported by Mr. K. M. Siedt.

Line No.	Description	Amount (1)	Amount (2)
1	Base revenues per books for the 12 months ending 3/31/2014		$ 741,232
	Normalizing adjustments:		
2	Customers - increase to yr end level	$ 677	
	Specific adjustments		
3	Roll-in of STAS		
4	Adjust for Energy Efficiency and Behind the Meter Generation	(10,018)	
5	Adjust for Other Revenues	-	
6	Eliminate unbilled revenues	(3,212)	
7	Total	$ (13,230)	
8	Normalizing adjustment (Lines 2+7)		(12,553)
9	Base revenues per books for the 12 months ending 3/31/2014, as adjusted		$ 728,679

Metropolitan Edison Company
Normalization Adjustment No. 2
$000

Adjustment of State Tax Adjustment Surcharge Revenues

To remove state tax adjustment surcharge ("STAS") revenues. Normalized STAS revenues are being rolled into base rates.

Line No.	Description	Amount (1)
1	STAS revenue per books for the 12 months ended 3/31/2014	$ (2,123)
2	Eliminate per budget STAS	2,123
3	Other operating revenue per books for the 12 months ended 3/31/2014, as adjusted	$ -

Metropolitan Edison Company
Normalization Adjustment No. 3
$000

Adjustment of Other Operating Revenues

To adjust other operating revenue to eliminate non-jurisdictional transmission revenues.

Line No.	Description	Amount (1)
1	Other operating revenue per books for the 12 months ended 3/31/2014	$ 70,921
2	Eliminate non-jurisdictional transmission revenues	(56,257)
3	Other operating revenue per books for the 12 months ended 3/31/2014, as adjusted	$ 14,664

Metropolitan Edison Company
Normalization Adjustment No. 4
$000

Adjustment of Distribution Expense

To adjust distribution payroll expense to reflect year end wage and employee levels, to adjust service company distribution payroll expense to reflect year end wage and employee levels, eliminate non-jurisdictional transmission expense and to include the distribution portion of the amortization of gains or losses to reacquired debt. The plant and labor allocation factors used in this normalization adjustment are supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	Amount (2)
1	Distribution expense per books for the 12 months ended 3/31/2014		$ 67,795
2	Distribution payroll expense adjustment to reflect year end employee levels, and ongoing wage and salary rates (Supporting Schedule No. 1, Line 12, Column 1)	$ 285	
3	Service Company Distribution payroll expense adjustment allocated to Met-Ed to reflect year end employee levels, and ongoing wage and salary rates (Supporting Schedule No. 1, Line 21, Column 1)	97	
4	Eliminate non-jurisdictional transmission expense	(9,174)	
5	Amortization of (gain) or loss on reacquired debt	$ 2,671	
6	Allocation ratio based on distribution plant	77.70%	
7	Distribution portion of (gain) or loss	$ 2,075	
8	Total normalizing adjustment (Lines 2 + 3 + 4 + 7)		(6,717)
9	Distribution expense per books for the 12 months ended 3/31/2014, as adjusted		$ 61,078

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 4
($000)

Adjustment to Payroll Expense to Reflect Year End Employee Levels and Wage Rates

Line No.	Description		Amount (1)	Amount (2)
1	Total payroll per books for the 12 months ended 3/31/2014 (Exhibit RAD-27)			$ 64,937
	Bargaining			
2	Straight time per books for the 12 months ended 3/31/2014		$ 33,939	
3	Straight time 3% increase effective 5/1/2014 (Line 2 x 3%)		1,018	
	Non-Bargaining			
4	Straight time per books for April 1 2013 through February 28, 2014		13,533	
5	Straight time 3% increase effective 9/1/2013 (Line 4 x 3%)		406	
6	Total company payroll adjustment (Line 3 + Line 5)			1,424
7	O&M allocation %		39.67%	
8	O&M payroll adjustment (Line 6 X Line 7)		$ 565	
9	Total Payroll as adjusted (Line 1 + Line 6)			$ 66,361
	Allocation of payroll adjustment:			
10	Price to Compare	0.00%	$ -	
11	Transmission	8.91%	50	
12	Distribution	50.40%	285	
13	Customer accounts	17.72%	100	
14	Customer service	8.42%	48	
15	Administrative and general	14.55%	82	
16	Total	100%	$ 565	
	Service Company (Exhibit RAD-25)			
17	Straight time per books for April 1, 2013 through February 28, 2014		$ 14,361	
18	Straight time 3% increase effective 9/1/2013 (Line 17 x 3%)		431	
	Allocation of Service Company payroll adjustment (Exhibit RAD-25):			
19	Price to Compare	1.03%	$ 4	
20	Transmission	6.20%	27	
21	Distribution	22.45%	97	
22	Customer accounting and Information	31.68%	136	
23	Administrative and general	38.64%	166	
24	Total	100%	$ 431	

Metropolitan Edison Company
Normalization Adjustment No. 5
$000

Adjustment of Customer Accounts Expense

To adjust customer account expense to reflect year end wage and employee levels, increased costs associated with added customers, and interest on customer deposits.

Line No.	Description	Amount (1)	Amount (2)
1	Customer Account expense per books for the 12 months ended 3/31/2014		$ 24,842
2	Customer Account payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates (Normalizing Adjustment No. 4, Supporting Schedule No. 1, Line 13, Column 1)	$ 100	
3	Service Company customer account payroll expense adjustment allocated to Met-Ed to reflect year end employee levels and ongoing wage & salary rates (Normalizing Adjustment No. 4, Supporting Schedule No. 1, Line 22, Column 1)	136	
4	Increased O&M costs associated with increased number of customers in normalized revenue levels (Supporting Schedule 1, Line 10)	12	
5	Interest on customer deposits (Supporting Schedule 2, Line 3)	1,287	
6	Total normalizing adjustment (Lines 2 + 3 + 4 + 5)		1,536
7	Customer Account expense per books for the 12 months ended 3/31/2014, as adjusted		$ 26,378

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 5
($000)

Adjustment of Other O&M Costs Associated with Serving New Customers

In association with the additional revenues from added customers reflected in Adjustment No. 1, there is also a cost associated with serving those customers. The Commission has previously recognized this and approved an adjustment to customer accounts expense for this increased cost. This cost is estimated by determining the ratio of non-payroll customer account expense to distribution revenues from customers and applying this ratio to the additional revenue received from increased customers. The distribution revenue is supported by Mr. K. M. Siedt.

Line No.	Description	Amount
		(1)
	Customer Account Expense Excluding Labor and Uncollectible	
1	Customer Account expense per books for the 12 months ended 3/31/2014	$ 24,842
2	Less: Distribution uncollectible expense	(14,346)
3	Less: Labor expense	(5,879)
4	Customer Account expense excluding labor and uncollectible expense	$ 4,617
	Total Base Revenue	
5	Distribution revenues per budget	$ 254,499
6	Late payment charges per books	3,583
7	Total	$ 258,082
8	Ratio of customer account expense to total revenue (Line 4 / Line 7)	1.79%
9	Revenue from added customers (Adjustment No. 1, Line 2)	$ 677
10	Additional expense from added customers (Line 8 x Line 9)	$ 12

Metropolitan Edison Company
Supporting Schedule No.2 to Normalizing Adjustment No. 5
($000)

Adjustment to Allow for Interest Expense on Customer Deposits

Customer deposits are included in rate base as a deduction, since these are funds supplied by customers to the company. Interest paid to customers on these deposits correspondingly has been recognized by the Commission as a expense when setting rates.

Line No.	Description	Amount (1)
1	Customer deposits included in rate base (Exhibit RAD-1 Column 1, Line 14)	$ 21,452
2	Interest rate on deposits	6%
3	Interest expense on customer deposits	$ 1,287

Metropolitan Edison Company
Normalization Adjustment No. 6
$000

Adjustment of Customer Service and Information Expense

To adjust customer service and information expense to reflect year end wage and employee levels.

Line No.	Description	Amount (1)	Amount (2)
1	Customer Service expense per books for the 12 months ended 3/31/2014		$ 40,005
2	Customer Service payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 14, Column 1)	$ 48	
3	Total normalizing adjustment		48
4	Customer Service expense per books for the 12 months ended 3/31/2014, as adjusted		$ 40,053

Metropolitan Edison Company
Normalization Adjustment No. 7
$000

Adjustment of Administrative and General Expense

To adjust Administrative and General expenses to reflect employee benefits expenses at year end personnel and wage levels, OPEB expense at the service cost level, pension expense to the ten year cash level, amortization of rate case expenses, the elimination of non-jurisdictional administrative and general expenses, and the elimination of distribution uncollectible accounts expense. Ms. L.W. Gifford supports the distribution uncollectible expenses. Hillary Stewart supports the non-jurisdictional expense allocation factor.

Line No.	Description	Amount (1)	Amount (2)
1	Administrative & general expense per books for the 12 months ended 3/31/2014		$ 6,525
2	Administrative & general expenses related to EE&C	$ (21,093)	
3	Administrative & general expenses related to Smart Meters	(7,570)	
4	Adjustment to administrative & general expenses	(28,663)	
5	Net administrative & general expenses related to distribution	(22,138)	
6	Administrative & general payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 15, Column 1)	82	
7	Service Company Administrative & general payroll expense adjustment allocated to Met-Ed to reflect year end employee levels and ongoing wage & salary rates (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 23, Column 1)	166	
8	Adjust OPEB expense to service cost level (Normalization Adjustment No. 7, Supporting Schedule No. 1, Line 12, Col. 1)	9,864	
9	Adjust pension expense to ten year cash level (Supporting Schedule No. 2, Line 18, Col. 3)	21,891	
10	Adjust employee benefit costs (Supporting Schedule No. 3, Line 8, Column 3)	295	
11	Subtotal of adjustments (Lines 6 + 7 + 8 + 9 + 10)		32,299
12	Administrative and general expense, adjusted	$ 10,161	
13	Non-jurisdictional expense allocation factor	10.43%	
14	Non-jurisdictional administrative and general expense		(1,060)
15	Rate case expenses to be incurred during current rate proceeding (Exhibit RAD-23)	$ 495	
16	Recovery period - years	2	
17	Annual amount (Line 15 / Line 16)		$ 248
18	Total normalizing adjustment (Lines 11 + 14 + 17)		$ 31,487
19	Administrative and general expense per books for the 12 months ended 3/31/2014, as adjusted		$ 38,012

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 7
$000

Adjustment for OPEB Expense

Budgeted OPEB expense consists of the current service cost, adjustments to prior years' service costs, and the financing component. This schedule adjusts the total budgeted expense amounts to the service cost. The service cost represents the actuarial present value of benefit liabilities accrued under the plan benefit formula for services rendered during the test year. Inclusion of the service cost in rates provides for recovery of the current cost of benefits earned by plan participants. Any excess or shortfall related to the expected return on plan assets are not included because their inclusion would artificially reduce or increase total costs and result in the recovery of more or less than the actual normal cost of service. The adjustment for OPEB expense to the current service cost amount was adopted by the Commission at Nos. Docket R-00061366 and R-00061367

Line No.	Description	O&M (1)	Capital (2)	Total (3)
1	O&M - Capital allocation ratios	39.67%	60.33%	100.00%
2	Company OPEB expense included on books	$ (8,758)	$ (13,320)	$ (22,078)
3	FirstEnergy Service Corp. OPEB expense	$ (16,375)	$ (24,904)	$ (41,279)
4	Allocation ratio	4.86%	4.86%	4.86%
5	Allocated FirstEnergy Service Corp. OPEB expense included on books (Line 3 X Line 4)	$ (796)	$ (1,210)	$ (2,006)
6	Total OPEB expense included on books (Line 2 + Line 5)	$ (9,554)	$ (14,530)	$ (24,084)
7	Service cost for company OPEB expense	$ 289	$ 440	$ 729
8	Service cost for FirstEnergy Service Corp. OPEB expense	$ 439	$ 668	$ 1,107
9	Allocation ratio	4.86%	4.86%	4.86%
10	Allocated FirstEnergy Service Corp. service cost (Line 8 x Line 9)	$ 21	$ 33	$ 54
11	Total OPEB service cost (Lines 7 + 10)	$ 310	$ 473	$ 783
12	Adjustment to set OPEB expense at ongoing service cost level (Lines 11 - 6)	$ 9,864	$ 15,003	$ 24,867

Metropolitan Edison Company
Supporting Schedule No. 2 to Normalizing Adjustment No. 7
$000

Adjustment for Pension Expense

To adjust budget pension expense to a ten year historical average level of actual cash contributions under the methodology that was adopted by the Commission at Docket Number R-00061366 and R-00061367.

Line No.	Description	Amount (1) Total	(2) O&M %	(3) O&M
	Company Cash Contributions			
1	2004 Cash Pension Contribution	$ 38,823	56.52%	$ 21,943
2	2005 Cash Pension Contribution	35,912	56.52%	20,297
3	2007 Cash Pension Contribution	11,012	55.42%	6,103
4	2009 Cash Pension Contribution	123,521	50.49%	62,366
5	2011 Cash Pension Contribution	35,000	45.09%	15,782
6	Total Company Cash Pension Contributions	$ 244,268		$ 126,490
	FirstEnergy Service Company Cash Contributions			
7	2004 Pension Contribution	$ 91,633		
8	2004 Company Allocation Factor	8.91%		
9	2004 Service Company Pension Contribution allocated to the Company	$ 8,165	56.52%	$ 4,615
10	2007 Pension Contribution	$ 27,468		
11	2007 Company Allocation Factor	11.29%		
12	2007 Service Company Pension Contribution allocated to the Company	$ 3,101	55.42%	1,719
13	Total FirstEnergy Service Company Cash Pension Contributions allocated to the Company (Line 9 + Line 12)	$ 11,266		$ 6,333
14	Total Pension cash contributions (Line 6 + Line 13)	$ 255,534		$ 132,824
15	Average	10		10
16	Pension expense cash contribution, amortized over 10 years	$ 25,553		$ 13,282
17	O&M Pension Expense included on the books			(8,609)
18	Adjustment to Pension Expense (Line 16 - Line 17)			$ 21,891

Metropolitan Edison Company
Supporting Schedule No. 3 to Normalizing Adjustment No. 7
$000

Adjustment to Employee Benefit Expense to Reflect Year End Employee Levels and Ongoing Wage Rates

Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 8 increases the O&M payroll expense. Associated with that increase are employee benefits charged to Administrative and General expense. This adjustment computes the added benefit costs on a normalized basis.

Employee benefits applicable to operating expenses:

Line No.		Effective Rate (a)	Payroll Adjustment		Benefit Adjustment
		(1)	(2)		(3) = (1) X (2)
1	Workers compensation	0.645%	$ 565	(b)	$ 4
2	Pension costs	37.616%	$ 565	(b)	213
3	OPEB costs	1.123%	$ 565	(b)	6
4	Life insurance	0.065%	$ 565	(b)	-
5	Medical insurance	9.415%	$ 565	(b)	53
6	Savings Plan	2.037%	$ 565	(b)	12
7	Other	1.177%	$ 565	(b)	7
8	Total increase due to payroll adjustment				$ 295

(a) Summary of effective employee benefit rates based on total payroll for the 12 months ending 3/31/14

	Total Amount	Total Payroll	Effective Rate
Workers compensation	$ 419	$ 64,937	0.645%
Pension costs - normalized basis	24,427	64,937	37.616%
OPEB costs - service cost	729	64,937	1.123%
Life insurance	42	64,937	0.065%
Medical insurance	6,114	64,937	9.415%
Savings Plan	1,323	64,937	2.037%
Other	764	64,937	1.177%

(b) Adjustment No. 4, Supporting Schedule No. 1, Line 8.

Metropolitan Edison Company
Normalization Adjustment No. 8
$000

Adjustment of Depreciation Expense

To adjust budgeted depreciation expense to reflect average remaining life rates on adjusted rate base, to eliminate non-jurisdictional expense, and to adjust cost of removal/ salvage expense to a five year average amount, according to prior commission practice and the adjustment of legacy meters. The plant allocation factor used in this normalization adjustment are supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	(2)	(3)	(4)
1	Depreciation expense per books for the 12 months ended 3/31/2014				$ 58,193
2	Cost of removal/salvage expense per budget for the 12 months ending 3/31/2014 (Exhibit RAD-30)		$ 10,222		
3	Depreciation accrual per books (Line 1 - Line 2)		$ 47,971		
4	Jurisdictional depreciation expense accrual on adjusted rate base at average remaining life rates (Exhibit RAD-53, page 2)		44,820		
5	Adjustment for average remaining life accrual for jurisdictional plant, (Line 4 - Line 3).			(3,151)	
6	Cost of removal/salvage expense per budget for the 12 months ending 3/31/2014 (Exhibit RAD-30)		$ 10,222		
	Cost of removal and salvage (Exhibit RAD-30)				
7	4/1/2009 - 3/31/2010	$ 17,539			
8	4/1/2010 - 3/31/2011	7,101			
9	4/1/2011 - 3/31/2012	17,511			
10	4/1/2012 - 3/31/2013	28,248			
11	4/1/2013 - 3/31/2014	10,222			
12	Total	$ 80,620			
13	Five year average (Line 12 / 5)		16,124		
14	Allocation ratio based on jurisdictional plant		77.70%		
15	Jurisdictional cost of removal/salvage expense to a jurisdictional five year average (Line 13 x 14)		12,528		
16	Adjustment of jurisdictional cost of removal/salvage expense to a jurisdictional five year average (Line 15 - Line 6)			2,306	
17	Adjustment for acceleration of legacy meters (Adj. 8 Sched 1, Line 6)			11,668	
18	Total normalizing adjustment (Lines 5 + 16 + 17)				10,824
19	Depreciation expense per books for the 12 months ended 3/31/2014, as adjusted				$ 69,017

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 8
$000

Adjustment for Acceleration for legacy meters

To accelerate recovery of legacy meters to fully recover all legacy meter costs over 5 years.

Line No.	Description	Amount (1)	Amount (2)
1	Legacy meters per budget for the 12 months ended 3/31/2014	$ 66,795	
2	Depreciation reserve per budget for the 12 months ending 3/30/2014	12,085	
3	Net legacy meters per budget for the 12 months ended 3/31/2014	$ 54,710	
4	Net estimated cost of removal and salvage	3,631	
5	Net legacy meters	$ 58,341	
6	Annual amortization over a 5 year amortization period		$ 11,668

Metropolitan Edison Company
Normalization Adjustment No. 9
$000

Adjustment of Amortization Expense

To include the amortization of deferred storm damage balances for Winter Storm Nika, approved at Docket No. P-2014-2412229, Hurricane Sandy, approved at Docket No. P-2013-2351260, and distribution non-capital storm expenses that exceeded 125% of storm costs included in base rates between the period of February 25, 2011 through September 30, 2012 as a result of the FirstEnergy and Allegheny Merger approved at Docket Nos. A-2010-2176520 and A-2010-2176732, including but not limited to Hurricane Irene, the October 2011 snowstorm, and Tropical Storm Lee. In addition, accretion expenses are removed.

Line No.	Description	Amount (1)	Amount (2)
1	Amortization expense per books for the 12 months ended 3/31/2014		$ 12,250
2	Deferred Nika storm damage	$ 13,327	
3	Deferred Sandy storm damage	21,497	
4	Merger storm deferral	30,140	
5	Total deferred storms (Lines 2+3+4)	$ 64,964	
6	Amortized over 3 years	3	
7	Annual Amortization	21,655	
8	Remove accretion expense	(58)	
9	Total normalization		21,597
10	Amortization expense per books for the 12 months ended 3/31/2014, as adjusted		$ 33,847

Metropolitan Edison Company
Normalization Adjustment No. 10
$000

Adjustment of Taxes Other Than Income

To adjust gross receipts tax expense to reflect normalized sales revenues, to adjust payroll tax expenses for normalized payroll and employee expenses. The non-jurisdictional allocation factor is supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	Amount (2)	Amount (3)
1	Taxes Other Than Income per books for the 12 months ended 3/31/2014			$ 50,525
2	Federal and State payroll taxes on books	$ 4,819		
3	Non-jurisdictional percent	10.43%		
4	Eliminate non-jurisdictional payroll taxes		$ (503)	
5	Capital Stock Tax included on books	$ 376		
6	PURTA tax on books	1,882		
7	Real Estate tax on books	134		
8	Total Other taxes	$ 2,392		
9	Non-jurisdictional percent	22.30%		
10	Eliminate non-jurisdictional taxes		(534)	
	Gross Receipts Tax			
11	Normalized sales revenues (Exhibit RAD-2, page 1, Col. 3)	$ 728,679		
12	Gross receipts tax @ 5.9%	42,992		
13	Gross receipts tax included on books	43,296		
14	Adjustment for gross receipts tax at normalized revenue level (Line 12 - Line 13)		(304)	
15	Adjustment for payroll taxes on normalized payroll, Supporting Schedule No. 1, Line 8		42	
16	Total normalizing adjustment (Lines 4 + 10 + 14 + 15)			(1,298)
17	Taxes other than income per books for the 12 months ended 3/31/2014, as adjusted			$ 49,227

Metropolitan Edison Company
Supporting Schedule No.1 to Normalizing Adjustment No. 10
$000

Adjustment to Taxes Other Than Income to reflect changes in payroll taxes.

Normalization adjustments have been made to normalize O&M payroll expense. Associated with those payroll normalizations are changes in FICA tax amounts.

Line No.	Description	Amount (1)
1	Total payroll per books for the 12 months ended 3/31/2014 Normalization Adjustment No. 4, Schedule 1, Line 1, Col 2	$ 64,937
2	Total payroll tax included on books	4,819
3	Effective payroll tax rate (Line 2 / Line 1)	7.421%
4	Total payroll as adjusted, Normalization Adjustment No. 4, Schedule 1, Line 9, Col. 2	$ 66,361
5	Payroll tax on normalized payroll (Line 3 X Line 4)	$ 4,925
6	Total Company payroll tax adjustment (Line 5 - Line 2)	$ 106
7	O&M Allocation percentage	39.67%
8	Adjustment for payroll tax (Line 6 x Line 7)	$ 42

Metropolitan Edison Company
Normalization Adjustment No. 11
$000

Computation of Federal & State Income Taxes - Normalized

Line No.	Description	Total Company Calculated Taxes (1)	Distribution Calculated Taxes (2)	PTC Calculated Taxes (3)	Universal Service Calculated Taxes (4)	Energy Efficiency Calculated Taxes (5)	Smart Meter Rider Calculated Taxes (6)	DSS Calculated Taxes (7)	Solar Calculated Taxes (8)	NUG Charge Calculated Taxes (9)	Storm Rider Calculated Taxes (10)	CEC Rider Calculated Taxes (11)
1	Total operating revenue	$ 769,405	$ 264,502	$ 400,758	$ 28,882	$ 29,531	$ 7,831	$ 26,795	$ 2,651	$ 8,194	$ -	$ 261
2	Less: Total O& M Expense	547,893	96,167	380,800	24,409	21,093	7,570	16,042	1,522	$ -	$ -	$ 290
3	Depreciation - accrual	56,488	56,359	-	-	-	129	-	-	-	-	-
4	Average net salvage	12,528	12,528	-	-	-	-	-	-	-	-	-
5	Amortization	33,847	11,795	(2,118)	3,164	6,659	(377)	6,232	938	7,573	-	(19)
6	Taxes other than income taxes	49,227	20,663	22,492	1,749	1,779	443	1,305	156	621	-	20
7	Total deductions	$ 699,984	$ 197,513	$ 401,175	$ 29,321	$ 29,531	$ 7,765	$ 23,579	$ 2,615	$ 8,194	$ -	$ 291
8	Net operating income before income taxes	$ 69,422	$ 66,989	$ (416)	$ (440)	$ -	$ 66	$ 3,216	$ 36	$ -	$ -	$ (30)
9	Less: Interest Charges (A)	34,799	34,754	-	-	-	45	-	-	-	-	-
10	Net income before income taxes	$ 34,623	$ 32,235	$ (416)	$ (440)	$ -	$ 21	$ 3,216	$ 36	$ -	$ -	$ (30)
	Adjustments to taxable income:											
11	Book Average net salvage	12,528	12,528	-	-	-	-	-	-	-	-	-
12	Adj. of book depreciation to tax basis (B)	$ 2,344	$ 2,850	$ -	$ -	$ -	$ (506)	$ -	$ -	$ -	$ -	$ -
13	Tax cost of removal/salvage	(5,087)	(5,087)	-	-	-	-	-	-	-	-	-
14	Adjust cash pension	21,891	21,891	-	-	-	-	-	-	-	-	-
15	Net adjustment	31,677	32,183	-	-	-	(506)	-	-	-	-	-
16	Income subject to state income tax	66,299	64,418	(416)	(440)	-	(485)	3,216	36	-	-	(30)
17	State income tax @ 9.99%	$ 6,623	$ 6,435	$ (42)	$ (44)	$ -	$ (48)	$ 321	$ 4	$ -	$ -	$ (3)
18	Taxes as budgeted	5,701	5,701	-	-	-	-	-	-	-	-	-
19	Adjustment to state income tax	$ 922	$ 734	$ (42)	$ (44)	$ -	$ (48)	$ 321	$ 4	$ -	$ -	$ (3)
20	Income subject to federal income tax	$ 59,676	$ 57,983	$ (375)	$ (396)	$ -	$ (436)	$ 2,895	$ 32	$ -	$ -	$ (27)
21	Federal income tax @ 35%	$ 20,887	$ 20,294	$ (131)	$ (139)	$ -	$ (153)	$ 1,013	$ 11	$ -	$ -	$ (9)
22	Taxes as budgeted	28,956	28,956	-	-	-	-	-	-	-	-	-
23	Adjustment to federal income tax	$ (8,069)	$ (8,662)	$ (131)	$ (139)	$ -	$ (153)	$ 1,013	$ 11	$ -	$ -	$ (9)
	(A) Computation of Interest charges											
	Total rate base	$ 1,335,350	$ 1,333,627	$ -	$ -	$ -	$ 1,723	$ -	$ -	$ -	$ -	$ -
	Debt ratio	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%
	Cost of debt	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%
	Interest expense	$ 34,799	$ 34,754	$ -	$ -	$ -	$ 45	$ -	$ -	$ -	$ -	$ -
	(B) Adjustment of book depreciation to tax basis:											
	Tax depreciation	54,144	53,509	-	-	-	635	-	-	-	-	-
	Book depreciation	56,488	56,359	-	-	-	129	-	-	-	-	-
	Depreciation adjustment	(2,344)	(2,850)	-	-	-	506	-	-	-	-	-

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalization Adjustment No. 11
$000

Computation of Federal & State Income Taxes - Normalized

To (1) split the tax depreciation into cost of removal, smart meter, and distribution components, and (2) calculate the jurisdictional allocation.

Line No.	Description	Amount (1)	(2)	(3)
1	Tax depreciation expense per books	$ 76,048		
2	Cost of removal / salvage	6,547	77.70%	5,087
3	Smart meter tax depreciation	635	100.00%	635
4	Distribution tax deprecation	$ 68,866	77.70%	53,509
5	Total tax depreciation			$ 54,144

Metropolitan Edison Company
Normalization Adjustment No. 12
$000

Adjustment of Provision for Deferred Income Taxes

This adjustment to the Provision for Deferred Income Taxes reflects (1) the adjustment of Federal deferrals to reflect year-end plant. All state deferred taxes associated with liberalized depreciation have been eliminated.

Line No.	Description	Provision for Deferred Taxes - Net	
		Federal	State
		(1)	(2)
1	Deferred taxes per books, 12 months ended 3/31/2014	$ (59,116)	$ -
2	Deferred taxes - liberalized depreciation (Exhibit RAD-41, page 19)	13,618	-
3	Jurisdictional allocation factor	77.70%	77.70%
4	Jurisdictional deferred taxes - liberalized depreciation (Line 2 X Line 3)	10,581	-
5	Adjustment to deferred tax expense (Line 4 - Line 1)	69,697	-
6	Deferred tax expense per books for the 12 months ended 3/31/2014, as adjusted	$ 10,581	$ -

Metropolitan Edison Company
Normalization Adjustment No. 13
$000

Adjustment of Investment Tax Credit

This adjustment is to eliminate the non-jurisdictional portion of investment tax credit adjustments.

Line No.	Description	Amount (1)	Amount (2)
1	Investment tax credit adjustments per books, 12 months ended 3/31/2014		$ (397)
2	Jurisdictional allocation factor	77.70%	
3	Jurisdictional investment tax credit (Line 1 x Line 2)	$ (308)	
4	Adjustment to investment tax credit expense (Line 3 - Line 1)		89
5	Adjustment to investment tax credit expense per books for the 12 months ended 3/31/2014, as adjusted		$ (308)

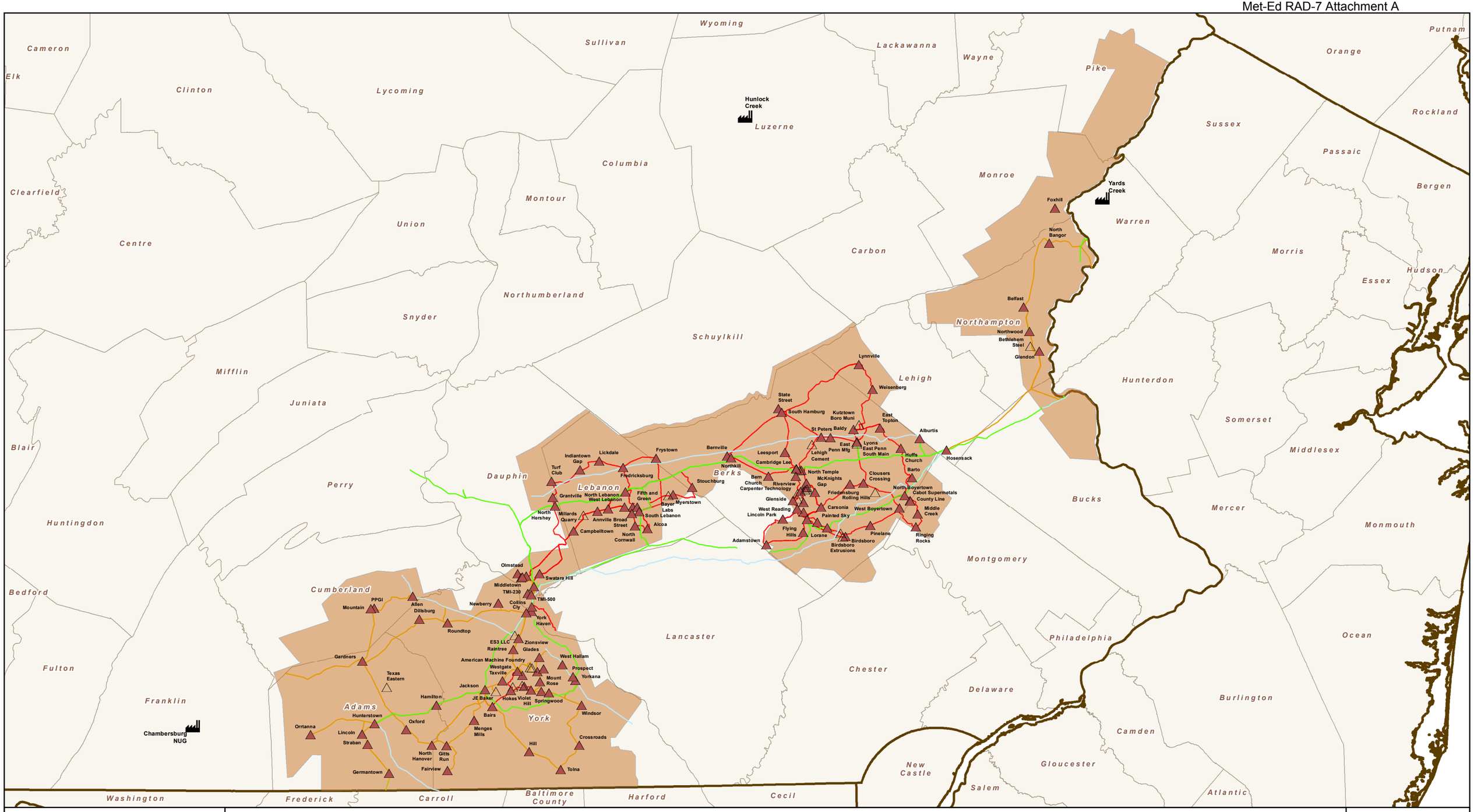
METROPOLITAN EDISON COMPANY

FILING REQUIREMENT I-B-3:

> "Provide an overall system map, including and labeling all generating plants, transmission substations—indicate voltage, transmission system lines—indicate voltage, and all interconnection points with other electric utilities, power pools, and other like systems."

RESPONSE:

See Met-Ed Exhibit RAD-7 Attachment A.



0 12.5 25 Miles

- Generation
- FE Owned Substation
- Customer Owned Substation
- Met-Ed

69 kV
115 kV
138 kV
230 kV
500 kV

Met-Ed Transmission System

N

Met-Ed®
A FirstEnergy Company

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METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-A-1:

"Provide a schedule showing the test year rate base and rates of return at original cost less accrued depreciation under present rates and under proposed rates. Claims made on this schedule should be cross-referenced to appropriate supporting schedules."

RESPONSE:

See Met-Ed Exhibit RAD-1 for the fully projected future test year.

See Met-Ed Exhibit RAD-3 for the future test year.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-A-2:

"If the schedule provided in response to item 1, is based upon a future test year, provide a similar schedule which is based upon actual data for the 12-month period immediately prior to the test year."

RESPONSE:

See Met-Ed Exhibit RAD-5 for the historical test year.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-A-3:

"When a utility files a tariff stating a new rate based in whole or in part on the cost of construction, as defined in 66 Pa.C.S. § 1308(f) (relating to voluntary changes in rates), of an electric generating unit, the utility shall identify:

(a) The total cost of the generating unit
(b) The following costs:
    (1) The cost and quantity of each category of major equipment, such as switchgear, pumps or diesel generators and the like.
    (2) The cost and quantity of each category of bulk materials, such as concrete, cable and structural steel and the like. .
    (3) Manual labor. .
    (4) Direct and indirect costs of architect/engineering services. .
    (5) Direct and indirect costs of subcontracts or other contracts involving major components or systems such as turbines, generators, nuclear steam supply systems, major structures and the like.
    (6) Distributed costs.
(c) A cost increase of $5 million or more, including AFUDC, over the original utility estimates provided under 66 Pa.C.S. § 515(a) (relating to construction cost of electric generating units) and its causes.
(d) Compliance with subsections (a) and (b) will be identical in format and substance as that provided under 52 Pa. Code § 57.103 (relating to estimate of construction costs) for original cost estimates submitted under 66 Pa.C.S. § 515(a)."

RESPONSE:

Not applicable.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-B-1:

"If a claim is made for plant held for future use, supply the following:

a. A description of the plant or land site and its cost and any accumulated depreciation.
b. The expected date of use for each item claimed.
c. An explanation as to why it is necessary to acquire each item in advance of its date of use.
d. The data when each item was acquired.
e. The date when each item was placed in plant held for future use."

RESPONSE:

There is no rate base claim being made in this proceeding for plant held for future use.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-B-2:

> "If a claim is made for construction work in progress, provide a supporting schedule which sets forth separately, revenue-producing and nonrevenue producing amounts, and include, for each category a summary of all work orders, amounts expended at the end of the test year and anticipated in service dates. Indicate if the construction work in progress will result in insurance recoveries, reimbursements, or retirements of existing facilities. Describe in exact detail the necessity of each project claimed if not detailed on the summary page from the work order. Include final completion dates and estimated total amounts to be spent on each project."

RESPONSE:

Met-Ed is not making any rate base claim for construction work in progress.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-B-3:

"If a claim is made for materials and supplies or fuel inventory provide a supporting schedule for each claim showing the latest actual 13 monthly balances and showing in the case of fuel inventory claims, the type of fuel, and location, as in station, and the quantity and price claimed."

RESPONSE:

METROPOLITAN EDISON COMPANY

13 Month Book Balance of Materials and Supplies

Line No.	Month	Amount *(in thousands)*
1	April 1, 2013	$ 13,926,128
2	April 30, 2013	13,653,200
3	May 31, 2013	14,667,989
4	June 30, 2013	15,853,993
5	July 31, 2013	15,953,474
6	August 31, 2013	15,927,057
7	September 30, 2013	15,557,251
8	October 31, 2013	15,623,111
9	November 30, 2013	15,240,945
10	December 31, 2013	13,458,084
11	January 31, 2014	13,682,065
12	February 28, 2014	14,092,822
13	March 31, 2014	14,493,114
14	13 Period Average	$ 14,779,172

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-B-4:

> "If a claim is made for cash working capital provide a supporting schedule setting forth the method and all detailed data utilized to determine the cash working capital requirement. If not provided in the support data provide a lead-lag study of working capital, completed no more than 6 months prior to the rate increase filing."

RESPONSE:

See the Direct Testimony of Patricia Larkin, Met-Ed/Penelec/Penn Power/West Penn Statement No. 6.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-B-6:

"Explain in detail by statement or exhibit the appropriateness of additional claims or the use of a method not previously mentioned, in the claimed rate base."

RESPONSE:

The supporting schedules included in Met-Ed Exhibit RAD-1 explain the appropriateness of various items claimed in the rate base. Items not explained in supporting schedules to Met-Ed Exhibit RAD-1, or not mentioned in other responses to filing requirements are explained below:

1. Customer Deposits

Customer deposits are deducted from the rate base as they represent a source of non-investor supplied capital. Appropriate interest on such deposits has been included as a normalizing adjustment to the income statement.

2. Customer Advances for Construction

In accordance with the practice followed in prior rate filings and accepted by Commission Orders, the Company reduces rate base by the amount of customer advances for construction at the end of the test year.

3. Operating Reserves

The Company has adopted a partial self-insurance concept for general and automotive liability insurance, property insurance and a long-term disability plan. The Company has also established an operating reserve for the purpose of providing a pension fund in addition to the normal funded plan. These operating reserves, net of applicable deferred taxes, reduce the Company's total rate base claim.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-C-1:

"Prepare a Statement of Income including:

(a) The book, or budgeted, statement for the test year.
(b) Adjustments to annualize and normalize under present rates, including an elimination of the effects on income of the energy cost rate and state tax adjustment surcharge.
(c) The income statement under present rates after adjustment.
(d) The adjustment for the revenue requested.
(e) The income statement under requested rates after adjustment.
(f) Each adjustment, including those relating to adjustment clauses, shall contain an explanation in sufficient clarifying detail to allow a reasonably informed person to understand the method and rationale of the adjustment."

RESPONSE:

Fully Projected Future Test Year

(a – f): See Met-Ed Exhibit RAD-2. Regarding part (b) pertaining to the annualization and normalization of revenues including applicable surcharges and tariff riders, these adjustments are supported in the Direct Testimony of Met-Ed Witness Kevin M. Siedt, Met-Ed Statement No. 4 and Met-Ed Exhibit KMS-1 Attachment A which accompanies his Direct Testimony.

Future Test Year

(a – f) See Met-Ed Exhibit RAD-4. Regarding part (b) pertaining to the annualization and normalization of revenues including applicable surcharges and tariff riders, these adjustments are supported in the Direct Testimony of Met-Ed Witness Kevin M. Siedt, Met-Ed Statement No. 4 and Met-Ed Exhibit KMS-1, Attachment B which accompanies his Direct Testimony.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-C-2:

"If the schedule provided in Filing Requirement II-C-1 is based upon budgeted data for a future test year, provide a similar schedule which is based upon actual data for the 12-month period immediately prior to the test year."

FILING REQUIREMENT II-C-1:

"Prepare a Statement of Income including:

(a) The book, or budgeted, statement for the test year.
(b) Adjustments to annualize and normalize under present rates, including an elimination of the effects on income of the energy cost rate and state tax adjustment surcharge.
(c) The income statement under present rates after adjustment.
(d) The adjustment for the revenue requested.
(e) The income statement under requested rates after adjustment.
(f) Each adjustment, including those relating to adjustment clauses, shall contain an explanation in sufficient clarifying detail to allow a reasonably informed person to understand the method and rationale of the adjustment."

RESPONSE:

(a – f): See Met-Ed Exhibit RAD-6. Regarding part (b) pertaining to the annualization and normalization of revenues including applicable surcharges and tariff riders, these adjustments are supported in the Direct Testimony of Met-Ed Witness Kevin M. Siedt, Met-Ed Statement No. 4 and Met-Ed Exhibit KMS-1, Attachment C which accompanies his Direct Testimony.

Metropolitan Edison Company
Comparative Income Statements

FERC Account		Twelve Months Ending April 30, 2016	March 31, 2015	Increase/ (Decrease)
Operating Revenues				
Electric Service Revenues				
440	Residential sales	$ 487,124	$ 495,246	$ (8,122)
442	Commercial sales	112,883	123,810	(10,927)
442	Industrial sales	51,258	50,866	392
444	Public street and highway lighting	5,410	5,141	269
445	Other sales to public authorities	-	-	-
447	Sale for resale	12,678	21,076	(8,398)
	Total electric service revenues	$ 669,354	$ 696,139	$ (26,785)
Other Electric Revenue				
450	Forfeited discounts	$ 3,229	$ 3,229	$ -
451	Miscellaneouse service revenues	1,903	1,903	-
454	Rent from electric property	19,477	19,477	-
456	Other electric revenues	47,656	47,885	(228)
	Total other electric revenues	$ 72,265	$ 72,494	$ (228)
	Total operating revenues	$ 741,619	$ 768,633	$ (27,014)
Operating Expenses				
401-2	Operation and maintenance expense			
	Power production expenses	$ 275,734	$ 320,216	$ (44,483)
	Transmission expenses	21,154	21,730	(577)
	Regional market expenses	54	50	4
	Distribution expenses	37,980	33,837	4,143
	Customer accounts expense	23,271	25,286	(2,015)
	Customer service & information expense	40,696	44,185	(3,488)
	Sales expenses	25	24	1
	Administrative & general expenses	41,116	37,806	3,310
	Subtotal	$ 440,030	$ 483,134	$ (43,104)
403	Depreciation expense	$ 59,721	$ 56,892	$ 2,829
404-5	Amortization and depletion of utility plant	4,710	2,681	2,029
406	Amortization and utility plant acq. adjustment	-	-	-
407	Amortization of property losses	-	-	-
407.3	Regulatory debits	22,920	24,410	(1,490)
407.4	Regulatory credits	15,407	(11,449)	26,856
408.1	Taxes other than income taxes	45,795	46,882	(1,086)
411.1	Accretion expense	49	62	(13)
411.8	Gains from disposition allowance	-	-	-
	Total operating expenses before federal and state income taxes	$ 588,632	$ 602,611	$ (13,980)
	Net operating income before income taxes	$ 152,987	$ 166,021	$ (13,034)
Income taxes				
409.1	Income taxes-federal	$ 39,423	$ 25,303	$ 14,121
409.1	Income taxes-state	-	-	-
410.1	Provision for deferred income taxes	49,263	67,085	(17,822)
411.1	Income taxes deferred in prior years-cr.	(42,966)	(39,764)	(3,202)
411.4	Investment tax credit adjustments-net	(364)	(364)	-
	Total income taxes	$ 45,356	$ 52,260	$ (6,903)
	Net operating income	$ 107,631	$ 113,762	$ (6,131)

Metropolitan Edison Company
Comparative Income Statements

FERC Account		Twelve Months Ending April 30, 2016	March 31, 2015	Increase/ (Decrease)
Other income				
415-16	Revenues from merchandising, jobbing and contract work	$ 2,808	$ 3,681	$ (872)
417	Revenues from non-utility operations	-	-	-
417.1	Expenses from non-utility operations	-	-	-
418	Nonoperating rental income	(17)	(17)	-
418.1	Equity in earnings of subsidiary companies	-	-	-
		-	-	-
419	Interest and dividend income	1,647	98	1,549
419.1	Allowance for funds used during construction	1,343	1,852	(509)
		-	-	-
421	Miscellaneous non-operating income	1,740	1,740	0
421.1	Gain on disposition of property	-	-	-
	Total other income	$ 7,522	$ 7,354	$ 168
	Gross income	$ 115,153	$ 121,115	$ (5,963)
Other Income Deductions				
421.2	Loss on disposition of property	$ -	$ -	$ -
425	Miscellaneous amortization	-	-	-
426	Other income deductions	146	146	0
	Total other income deductions	$ 146	$ 146	$ 0
Taxes Applicable to Other Income and Deductions				
408.2	Taxes other than income taxes	$ -	$ -	$ -
409.2	Income taxes - federal	-	-	-
409.2	Income taxes - state	-	-	-
410.2	Provision for deferred income taxes	-	-	-
411.2	Provision for deferred income taxes-cr.	-	-	-
	Total taxes on other income and deductions	$ -	$ -	$ -
Interest Charges				
427	Interest on long term debt	$ 51,862	$ 40,717	$ 11,145
428	Amortization of debt discount and expense	911	700	210
		-	-	-
428.1	Amortization of loss on reacquired debt	247	544	(297)
		-	-	-
429	Amortization of premium on debt credit	-	-	-
429.1	Amortization of gain on reacquired debt	(144)	(144)	-
430	Interest on debt to associated companies	8	1,036	(1,028)
431	Other interest expense	3,859	4,152	(293)
432	Allowance for borrowed funds used during construction - credit	(892)	(1,229)	338
		-	-	-
	Total interest charges	$ 55,852	$ 45,776	$ 10,076
	Income before extraordinary items	$ 59,155	$ 75,194	$ (16,039)
Extraordinary Items & Related Taxes				
434	Extraordinary income	$ -	$ -	$ -
435	Extraordinary deductions	-	-	-
409.3	Income taxes - Federal & other	-	-	-
	Extraordinary items after taxes	$ -	$ -	$ -
	Net income	$ 59,155	$ 75,194	$ (16,039)

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-1

"Provide a schedule showing all revenues and expenses for the test year and for the 12-month period immediately prior to the test year, together with an explanation for major variances between test year revenues and expenses and those for the previous 12-month period. Revenues and expenses shall be summarized by the major account categories listed below. If budgeted data for a future test year is not readily available by these categories, an analysis of the data for the 12-month period immediately prior to the future test year or for the most recent available calendar year may serve as the basis for ratably allocating the budgeted data into the account categories as follows:

OPERATING REVENUES

	Electric Revenues:
	Residential Sales
	Commercial Sales
	Industrial Sales
400	Public Street & Highway
	Lighting Sales
	Sales for Resale
	Total Other Electric Revenues
	Other Electric Revenues:
	Late Payment Charges
	Miscellaneous Service Revenues
	Rent from Electric Property
	Other Electric Revenues
	Total Other Electric Revenues
	Total Operating Revenues

OPERATING EXPENSES

	Operation and Maintenance Expenses
	Power Production Expenses:
	Fuel
401-2	Net Interchange
	Deferred Energy Costs
	Other
	Transmission Expenses
	Distribution Expenses
	Customer Service & Informational Expense
	Sales Expenses

	Administrative and General Expenses
	Total Operation & Maintenance Expenses
403	Depreciation Expenses
	Amortization of Net Salvage
	Nuclear Decommissioning Expense
407	Amortization of Property Losses
	Taxes Other Than Income Taxes
408	Total Operating Expenses Prior To Federal & State Income Taxes

OPERATING EXPENSES

	Operating Income Prior To Federal and State Income Taxes

FEDERAL AND STATE INCOME TAXES

	Federal Income Taxes
409	State Income Taxes
409	Deferred Federal Income Taxes
	Deferred State Income Taxes
	Investment Tax Credit Adjustments
411	Deferrals
	Amortization—Credit
	Other Income Tax Credits & Charges
	Total Federal and State Income Taxes
	Operating Income After Federal and State Income Taxes

OTHER INCOME AND DEDUCTIONS
OTHER INCOME

415-18	Non-utility Operating Income
419	Interest and Dividend Income
419	Allowance for Other Funds Used During Construction
421	Gain on Disposition of Property
421	Other Miscellaneous Non-operating Income
	Total Other Income

OTHER INCOME DEDUCTIONS

421	Loss on Disposition of Property
425	Miscellaneous Amortization
426	Miscellaneous
	Total Other Income Deductions

TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS

408	Taxes Other Than Income Taxes
409	Federal Income Tax

409	State Income Tax
	Total Taxes Applicable to Other Income and Deductions
	Income Before Interest Charges

INTEREST CHARGES

427	Interest on Long-Term Debt
428	Amortization of Debt Discount and Expense
429	Amortization of Premium on Debt
431	Other Interest Expense
432	Allowance for Borrowed Funds Used During Construction—Credit
	Net Interest Charges
	Income Before Extraordinary Items
	Extraordinary Items After Taxes
	Net Income "

RESPONSE:

See Exhibit RAD-18 Attachment A which provides the requested comparative operating statements. Set forth below are explanations of the causes of major variances.

OPERATING REVENUES

Residential Sales (Variation ($8,122))

The variance is due primarily to decreases of $16.2 million in the Hourly Pricing Service revenue and $1.5 million in the NUG Rider Energy charge offset by increases of $7.2 million in the Universal Service Charge and $1.6 million in the Smart Meter Technology revenues.

Commercial Sales (Variation ($10,927))

The variance is due primarily to decreases of $11.7 million in the Hourly Pricing Service revenue and $0.9 million in the NUG Rider Energy charge offset by increases of $1.0 million in the Smart Meter Technology revenues.

Sales for Resale (Variation ($8,398))

The variance is due primarily to an $8.0 million decrease to PJM Spot market energy revenues.

OPERATING EXPENSES

Operation and Maintenance expense Account 401-2 (Variance ($43,104))

The variance is primarily due to decreases of $44.5 million in purchased power, and $3.5 million in customer assistance expenses. These decreases were partially offset by increases of $4.1 million in distribution expenses, and $3.3 million in administrative & general expenses.

Account 403 Depreciation expense (Variance $2,829)

The variance is due primarily to a $2.8 million increase in depreciation on assets offset by $0.1 million decrease in depreciation cost of removal.

Account 404-5 Amortization and depletion of utility plant (Variance $2,029)

The variance is due primarily to a $2.0 million increase in amortization and depletion on assets.

Account 407.3 Regulatory debits (Variance ($1,490))

This variance is due primarily to a $3.8 million decrease in the NUG deferral offset partly by a $1.3 increase in the DSSR deferral and a $1.0 increase in the 2006 PJM Transmission deferral.

Account 407.4 Regulatory credits (Variance $26,856)

This variance is due primarily to increases of $13.8 million in the Price to Compare deferral, $10.6 million in the Universal Service deferral, $1.7 million in the Energy Efficiency deferral, and $1.5 million in the Smart Meter deferral.

Account 408.1 Taxes other than income taxes (Variance ($1,086)

This variance is due primarily to a decrease of $1.2 million in the PA gross receipts tax.

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METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-2:

"Provide a summary of test year adjustments which sets forth the effect of the adjustment upon the following: operating revenues, operating expenses, taxes other than income taxes, operating income before income taxes, State income tax, Federal income tax and income available for return. In addition, test year adjustments shall be presented on the basis of the major account categories set out at II-D-1."

RESPONSE:

See Met-Ed Exhibit RAD-19 Attachment A.

Metropolitan Edison Company

Line No.	Adj. No.	Support Schedule No.	Description	Operating Revenues (1)	Operating Expenses (2)	Taxes Other Than Income Taxes (3)	Operating Income Before Income Taxes (4)	State Income Tax (5)	Federal Income Tax (6)	Income Available for Return (7)=(4)-(5)-(6)
1			As budgeted (Exhibit RAD-2, Page 1, col. 1)	$ 741,619	$ 545,899	$ 42,733	$ 152,987	$ -	$ 45,356	$ 107,631
			Normalizations and Adjustments							
			Operating Revenues							
2	1		Base Operating Revenues	25			25	2	8	15
3	2		State Tax Surcharge Revenues	-			-	-	-	-
4			Other Operating Revenues				-	-	-	-
5	3		Eliminate non-jurisdictional transmission revenues	(55,404)			(55,404)	(5,535)	(17,454)	(32,415)
										-
			Operating Expenses							-
			Distribution							
6	4	1	Distribution payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	263			(263)	(26)	(83)	(154)
7	4	1	Service company distribution payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	66			(66)	(7)	(21)	(39)
8	4		Eliminate non-jurisdictional transmission expense	(9,140)			9,140	913	2,879	5,347
9	4		Amortization of gain or loss on reacquired debt	81			(81)	(8)	(26)	(47)
			Customer Accounts							
10	5		Customer account payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	92			(92)	(9)	(29)	(54)
11	5		Service company customer account payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	99			(99)	(10)	(31)	(58)
12	5	1	Increased O&M costs associated with increased number of customers in normalized revenue levels	10			(10)	(1)	(3)	(6)
13	5	2	Interest on customer deposits	1,256			(1,256)	(125)	(396)	(735)
			Customer Service							
14	6		Customer service payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	44			(44)	(4)	(14)	(26)
			Administrative & General Expenses							
15	7		A&G payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	76			(76)	(8)	(24)	(44)
16	7		Service company A&G payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	148			(148)	(15)	(47)	(87)
17	7	1	Adjust OPEB expense to service cost level	2,814			(2,814)	(281)	(887)	(1,646)
18	7	2	Adjust Pension Expense to ten year cash level	14,046			(14,046)	(1,403)	(4,425)	(8,218)
19	7	3	Adjust employee benefit costs	305			(305)	(30)	(96)	(178)
20	7		Adjustment to remove non-jurisdictional A&G expense	(2,660)			2,660	266	838	1,556
21	7		Rate Case expenses normalized over 2 years	(502)			502	50	158	294
22	7		Increase in O&M costs for accelerated (3 day) switching for customers moving to a new supplier	311			(311)	(31)	(98)	(182)
23	7		Less legacy meters from budget	(330)			330	33	104	193
			Depreciation Expense							
24	8		Adjustment for average remaining life accrual for jurisdictional plant	(7,041)			7,041	703	2,218	4,119
25	8		Adjustment of cost of removal/salvage expenses to a jurisdictional five year average	8,020			(8,020)	(801)	(2,527)	(4,692)
26	8	1	Adjustment for amortization of legacy meters	10,759			(10,759)	(1,075)	(3,389)	(6,295)
			Amortization							
27	9		Adjustment for storms	21,655			(21,655)	(2,163)	(6,822)	(12,670)
28	9		Remove rate case expenses from budget	750			(750)	(75)	(236)	(439)
29	9		Remove legacy meters from budget	330			(330)	(33)	(104)	(193)
30	9		Remove accretion expense	(49)			49	5	15	29
			Taxes Other than Income							
31	10		Eliminate non-jurisdictional payroll taxes			(490)	490	49	154	287
32	10		Eliminate other non-jurisdictional taxes			(503)	503	50	158	294
33	10		Adjustment for gross receipts tax at normalized revenue level			13	(13)	(1)	(4)	(8)
34	10	1	Adjustment for payroll taxes on normalized payroll			40	(40)	(4)	(13)	(23)

Line No.	Adj. No.	Support Schedule No.	Description	Operating Revenues (1)	Operating Expenses (2)	Taxes Other Than Income Taxes (3)	Operating Income Before Income Taxes (4)	State Income Tax (5)	Federal Income Tax (6)	Income Available for Return (7)=(4)-(5)-(6)
			Federal & State Income Taxes							
			Income Taxes							
35	11		Current federal & state income taxes				-	15,679	10,020	(25,698)
36	12		Deferred federal & state income taxes				-		(2,699)	2,699
37	13		Amortization of ITC	-	-	-	-	-	81	(81)
38			Total adjustments (Exhibit RAD-2, Page 1, col. 2)	$ (55,379)	$ 41,403	$ (940)	$ (95,842)	$ 6,104	$ (22,792)	$ (79,154)
39			Budget as Adjusted (Exhibit RAD-2, Page 1, col. 3)	$ 686,240	$ 587,302	$ 41,793	$ 57,145	$ 6,104	$ 22,564	$ 28,477
40			Adjustments to achieve required return - Total PaPUC Jurisdictional	152,643	-	9,006	143,637	14,349	45,251	84,038

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-3:

"List and explain all nonrecurring or extraordinary expenses incurred in the test year and all expenses included in the test year which do not occur yearly but are of a nature that they do occur over an extended period of years, for example, nonyearly maintenance programs, and the like."

RESPONSE:

The test year ending 4/30/16 does not include any non-recurring or extraordinary expenses.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-4:

"As a separate item, list extraordinary property losses related to property previously included in cost of service when the gain or loss on this property has occurred or is likely to occur in the future test year. The proposed ratemaking treatment of extraordinary gains and losses must also be disclosed. Sufficient supporting data must be provided."

RESPONSE:

There are no extraordinary property losses.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-5:

"Provide the amount of accumulated reserve for uncollectible accounts, method and rate of accrual, amounts accrued and amounts written off in each of the last 3 calendar years."

RESPONSE:

The future estimate of uncollectible accounts is based on a historically determined average of net write-offs to sales for each utility company. For the Uncollectible Customer Reserve, the regulated utility companies at FirstEnergy determine a 3-year rolling average of net write-offs to sales (36 months of net write-offs/ 36 months of sales). This percentage is then multiplied by the latest 6 months of sales to arrive at a reserve.

Beginning in 2013, the Uncollectible Customer Reserve includes a reserve for the Purchase of Receivables program (POR). This is determined by using a percentage of Non- POR Uncollectible Customer Reserve to Non- POR Customer Receivable Arrears (Uncollectible Customer Receivable Reserve/Non-Current Customer Receivable Arrears). This percentage is then multiplied by the POR Non-Current Customer Receivable Arrears to arrive at a reserve.

The Utility may record additional uncollectible customer reserve amounts as deemed necessary to fairly value Accounts Receivable.

The accruals, net write-offs and balance in FERC Account No. 144.1 Accumulated Reserve for Uncollectible Accounts for the last three calendar years are as follows:

Line No.	Description	Amount
1	**Balance, January 1, 2011**	$ (3,867,730)
2	Accruals	$ (11,522,378)
3	Write-offs (Net)	$ 12,374,770
4	**Balance, December 31, 2011**	$ (3,015,338)
5	Accruals	$ (12,841,208)
6	Write-offs (Net)	$ 12,833,226
7	**Balance, December 31, 2012**	$ (3,023,320)
8	Accruals	$ (14,333,240)
9	Write-offs (Net)	$ 10,315,484
10	**Balance, December 31, 2013**	$ (7,041,076)

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-6:

"Supply detailed calculations to support the total claim for rate case expense, including supporting data for outside service rendered. Provide the items comprising the estimated rate case expense claim for the current rate case."

RESPONSE:

The claim in the current rate case proceeding for rate case expenses, shown on Met-Ed Exhibit RAD-2 page 18, is based on the following total estimated expenses proposed to be amortized for ratemaking purposes over two years:

	Amount ($000)
Legal Expenses	$ 275
Expert Witnesses	33
Other	187
Total	$ 495

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-7:

"Submit schedules for the test year and for the 12-month period immediately prior to the test year showing by major components, if included in claimed test year expenses, the expenses incurred in each of the following expense categories:

(a) Miscellaneous general expenses, including account 930.
(b) Outside service expenses.
(c) Regulatory commission expenses.
(d) Advertising expenses, including advertising engaged in by trade associations whenever the utility has claimed a contribution to the trade association as a ratemaking claim - provide explanation of types and purposes of such advertising.
(e) Research and development expenses – provide a listing of major projects.
(f) Charitable and civic contributions, by recipient and amount.

Explain major variances between the test year expenses and those expenses for the prior 12-month period."

RESPONSE:

(a) – (d) See Page 2 of 3
(e) – (f) See Page 3 of 3

Line No.	Description	12 Months Ending April 30 2016	March 31 2015	March 31 2014
			(in thousands)	
	Acct 913 - Advertising & 930 - Miscellaneous General Expense			
	Institutional or Goodwill Advertising Expenses (913 & 930.1)			
1	Goodwill Advertising	$ 35	$ 34	$ 24
2	Print Advertising	-	-	65
3	Radio Advertising	-	-	8
2	Total Institutional or Goodwill Advertising	$ 35	$ 34	$ 97
	Misc. General Expenses (930.2)			
3	Bank Fees	$ 209	$ 209	$ 174
4	Misc Regulatory Expenses	192	242	236
5	Corporate Dues - Trade	133	133	116
6	Financing Admin Fees	123	123	195
7	Corporate Dues - Civic	39	39	27
8	Association Fees and Dues	3	3	4
9	Licenses, Permits & Regulation	-	-	7
10	FENOC - Benefits	-	-	6
11	FENOC - Tax	-	-	3
12	Other Miscellaneous Expenses	-	-	11
13	Total Miscellaneous General Expenses	$ 698	$ 748	$ 778
14	Accounts 913 & 930	$ 733	$ 782	$ 876
	Account 923 - Outside Services Employed			
1	Outside Contractors	$ 19,232	$ 22,987	$ 17,732 (A)
2	FE Service Co. Assessments	16,146	15,840	14,831
3	FENOC	7	7	42
4	West Penn	2	2	1
5	Penelec	1	1	1
6	Total Account 923	$ 35,388	$ 38,837	$ 32,607
	Account 928 - Regulatiory Commission Expenses			
1	Regulatory Commission Expense	$ 2,632	$ 2,469	$ 2,460
2	Total Account 928	$ 2,632	$ 2,469	$ 2,460

(A) The variance in Outside Contractors expense is due primarily to fluctuations in Smart Meter and Energy Efficiency programs.

Line No.	Description of Project	12 Months Ending April 30 2016	12 Months Ending March 31 2015	12 Months Ending March 31 2014	
		(in thousands)			
1	***Research and Development Expenditures***	$ 145	$ 141	$ 218	(B)

(B) For the year ended March 31, 2014, R&D expenses represents actual amounts included in the income statement. Future amounts are projected expenditures which will settle to either capital or expense depending on the nature of the project.

Acct. 426.1 -- Donations

Organizations				
1	Property Donations	$ 117	$ 117	$ 108
2	Civic Donations	19	19	29
4	Total charitable and civic contributions	$ 136	$ 136	$ 137

Metropolitan Edison Company
Charges by Affiliates
(000's)

Line No.	Description	Twelve Months Ending April 30, 2016 Labor *	Other than Labor **	Total	Twelve Months Ending March 31, 2015 Labor *	Other than Labor **	Total	Twelve Months Ending March 31, 2014 Labor *	Other than Labor **	Total
1	Production	$ -	$ -	$ -	$ -	$ -	$ -	$ 161	213	$ 374
2	Transmission	967	1,186	2,153	933	1,153	2,086	971	628	1,600
3	Distribution	2,623	1,395	4,018	2,479	1,372	3,852	3,517	2,293	5,810
4	Customer Accounting and Information	3,941	3,405	7,346	3,917	3,419	7,336	4,963	3,592	3,480
5	Administrative and General	5,904	11,531	17,435	6,509	10,179	16,689	6,054	6,533	17,661
6	Total	$13,435	$ 17,516	$ 30,951	$13,839	$ 16,124	$ 29,963	$ 15,666	$ 13,260	$ 28,925

* Labor is direct payroll only; excludes payroll overhead
** OTL includes payroll overhead

SERVICE AGREEMENT

This Service Agreement ("Agreement") is entered into as of the 25th day of February, 2011, by and between each of the associate companies listed on the signature page hereto (each a "Client Company"), and FirstEnergy Service Company, an Ohio corporation ("Service Company").

WHEREAS, Service Company is a direct wholly-owned subsidiary of FirstEnergy Corp., a holding company under the Public Utility Holding Company Act of 2005, as amended (the "Act");

WHEREAS, Service Company has been formed for the purpose of providing administrative, management and other services to FirstEnergy Corp. and its associate companies, including Client Company (together, the "Client Companies"); and

WHEREAS, Client Company believes that it is in its interest to enter into an arrangement whereby Client Company may agree to purchase such administrative, management and other services from Service Company as Client Company may choose at cost as determined in accordance with this Agreement and the Act;

NOW, THEREFORE, in consideration of the mutual covenants contained herein and other valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, intending to be legally bound, hereby agree as follows:

1. DESCRIPTION OF SERVICES.

Service Company agrees to provide certain administrative, management or other services (the "Services") to Client Company similar to those supplied to other Client Companies of Service Company. Such services are and will be provided to Client Company only at the request of Client Company. Exhibit A hereto lists and describes all of the Services that are available from Service Company.

2. PERSONNEL.

In order to provide the Services, Service Company will employ executive officers, accountants, financial advisers, technical advisers, attorneys and other persons with the necessary qualifications. If necessary, Service Company may also arrange for the services of nonaffiliated experts, consultants and attorneys in connection with the performance of any of the Services provided under this Agreement.

3. COMPENSATION AND ALLOCATION.

As and to the extent required by law, Service Company provides and will provide such services at fully allocated cost, determined in accordance with the Act. Exhibit A hereof contains rules for determining and allocating such costs.

4. TERMINATION AND MODIFICATION.

Either party to this Agreement may terminate this Agreement by providing 60 days written notice of such termination to the other party. This Agreement is subject to termination or modification at any time to the extent its performance may conflict with the provisions of the Act or with any rule, regulation or order of the Federal Regulatory Energy Commission (the "Commission") adopted before or after the making of this Agreement. This Agreement shall be subject to the approval of any state commission or other state regulatory body whose approval is, by the laws of said state, a legal prerequisite to the execution and delivery or the performance of this Agreement.

5. SERVICE REQUESTS.

Client Company and Service Company will prepare a Service Request on or before September 30th of each year listing Services to be provided to Client Company by Service Company and any special arrangements related to the provision of such Services for the coming year, based on Services provided during the preceding year. Client Company and Service Company may supplement the Service Request during the year to reflect any additional or special Services that Client Company wishes to obtain from Service Company, and the arrangements relating thereto.

6. BILLING AND PAYMENT.

Unless otherwise set forth in a Service Request, payment for Services provided by Service Company shall be by making remittance of the amount billed or by making appropriate accounting entries on the books of Client Company and Service Company. Billing will be made on a monthly basis, with the bill to be rendered as soon as practicable after the close of the month, and remittance or accounting entries completed within 30 days of billing. Any amount remaining unpaid after 30 days following receipt of the bill shall bear interest thereon from the due date of the bill until payment at a rate equal to the prime rate on the due date.

7. NOTICE.

Where written notice is required by this Agreement, all notices, consents, certificates, or other communications hereunder shall be in writing and shall be deemed given when mailed by United States registered or certified mail, postage prepaid, return receipt requested, addressed as follows:

To Client Company: c/o President
76 South Main St.
Akron, Ohio 44308

To Service Company: c/o Vice President and Controller
76 South Main Street
Akron, Ohio 44308

8. GOVERNING LAW.

This Agreement shall be governed by and construed in accordance with the laws of the State of Ohio, without regard to its conflict of laws provisions.

9. MODIFICATION.

No amendment, change or modification to this Agreement shall be valid, unless made in writing and signed by both parties hereto.

10. ENTIRE AGREEMENT.

This Agreement, together with its exhibits, constitutes the entire understanding and agreement of the parties with respect to its subject matter, and effective upon the execution of this Agreement by the respective parties hereof, any and all prior agreements, understandings or representations with respect to this subject matter are hereby terminated and canceled in their entirety and are of no further force and effect, except to the extent transactions thereunder have taken place prior to such effective date in which case such agreements will govern the terms of such transactions.

11. WAIVER.

No waiver by either party hereto of a breach of any provision of this Agreement shall constitute a waiver of any preceding or succeeding breach of the same or any other provision hereof.

12. ASSIGNMENT.

This Agreement shall inure to the benefit and shall be binding upon the parties and their respective successors and assigns. No assignment of this Agreement or either party's rights, interests or obligations hereunder may be made without the other party's consent, which shall not be unreasonably withheld, delayed or conditioned.

13. SEVERABILITY.

If any provision or provisions of this Agreement shall be held by a court of competent jurisdiction to be invalid, illegal, or unenforceable, the validity, legality, and enforceability of the remaining provisions shall in no way be affected or impaired thereby.

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed effective as of the 25th day of February, 2011. This Agreement supercedes any previous agreement between the Service Company and the Client Companies.

FirstEnergy Service Company

By: _____
Harvey L. Wagner
Vice President & Controller

Client Companies:

Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company
Pennsylvania Power Company
American Transmission Systems, Incorporated
Pennsylvania Electric Company
Waverly Electric Power & Light Company
Metropolitan Edison Company
Monongahela Power Company
The Potomac-Edison Company
West Penn Power Company
PATH - Allegheny Land Acquisition Company
PATH Allegheny Maryland Transmission Company, LLC
PATH Allegheny Transmission Company, LLC
PATH Allegheny Virginia Transmission Corporation
AYE Series, Potomac-Appalachian Transmission Highline, LLC
Trans-Allegheny Interstate Line Company

By: _____
Charles E. Jones
President

Jersey Central Power & Light Company

By: _____

Donald M. Lynch
President

EXHIBIT A
DESCRIPTION OF SERVICES AND ALLOCATION METHODOLOGY

1. Description Of Services

Overview

This Exhibit provides a description of all services provided by Service Company departments and the cost allocation methodologies to be used in connection therewith. All products and services are subject to Service Level Standards as negotiated between the Service Company department and Client Company. Each Client Company is classified as either a "Utility Subsidiary" or a "Non-Utility Subsidiary".

2. Cost Allocation Methodology

Overview

The costs of services provided by Service Company will be directly assigned, distributed or allocated by activity, project, program, work order or other appropriate basis. The primary basis for charges to affiliates is the direct charge method. The methodologies listed below pertain to all other costs which are not directly assigned but which make up the fully allocated cost of providing the product or service. The costs of product and services provided by the ServeCo that cannot be charged directly to the Subsidiary receiving the product or service will be allocated among the associate companies by utilizing one of the methods described below that most accurately distributes the costs. The method of cost allocation varies based on the department rendering the service. The allocation methods used by Service Company are as follows:

a. **"Multiple Factor – All"** - For the Indirect Costs for products or services benefiting the entire FirstEnergy system, FirstEnergy and all Subsidiaries will bear a fair and equitable portion of such costs. FirstEnergy will bear 5% of these Indirect Costs. The remaining Indirect Costs will be allocated among the Utility Subsidiaries and the Non-Utility Subsidiaries benefiting from the services provided based on FirstEnergy's equity investment in the respective groups. A subsequent allocation step will then occur. Among the Utility Subsidiaries, allocations will be based upon the **"Multiple Factor - Utility"** method. Among the Non-Utility Subsidiaries, allocations will be based upon the **"Multiple Factor - Non-Utility"** method.

b. **"Multiple Factor – Utility"** - For the Indirect Costs for a product or service solely benefiting one or more of the Utility Subsidiaries, each such Utility Subsidiary so benefiting will be charged a portion of the Indirect Costs based on the sum of the weighted averages of the following factors:

1. Gross transmission and/or distribution plant
2. Operating and maintenance expense excluding purchase power and fuel costs

3. Transmission and/or distribution revenues, excluding transactions with affiliates

These three (3) factors have been determined to be the most appropriate for the Utility Subsidiaries in the FirstEnergy system. Each factor will be weighted equally so that no one facet of the electric utility operations inordinately influences the distribution of Indirect Costs.

c. **"Multiple Factor - Non-Utility"** - For the Indirect Costs for products or services solely benefiting the Non-Utility Subsidiaries, each Non-Utility Subsidiary so benefiting receiving the product or service will be charged a proportion of the Indirect Costs based upon the total assets of each Non-Utility Subsidiary, including the generating assets under operating leases from the Utility Subsidiaries.

d. **"Multiple Factor - Utility and Non-Utility"** - For the Indirect Costs for a product or service benefiting one or more of the Utility and Non-Utility Subsidiaries, each such Subsidiary so benefiting is first assigned a distribution ratio that is in proportion to the Indirect Costs based on FirstEnergy's equity investment in such Subsidiaries. Following this distribution, a subsequent allocation step will then occur. Among the Utility Subsidiaries, allocations will be based upon the **"Multiple Factor-Utility."** Among the Non-Utility Subsidiaries, allocations will be based upon **"Multiple Factor - Non-Utility"**

e. **"Direct Charge Ratio"** - The ratio of direct charges for a particular product or service to an individual Subsidiary as a percentage of the total direct charges for a particular product or service to all Subsidiaries benefiting from such services. Indirect Costs are then allocated to each Subsidiary based on the calculated ratios.

f. **"Number of Customers Ratio"** - For costs of products and services driven by the number of Utility customers, the allocation method that will be used will be the number of Utility customers for the respective Utility Subsidiary receiving the product or service divided by the total number of utility customers.

g. **"Number of Shopping Customers Ratio"** - A "shopping customer" is defined as a Utility customer who has selected a competitive electric generation supplier. For costs of products and services driven by the number of shopping customers, the allocation method that will be used will be the number of shopping customers for the respective Utility Subsidiary receiving the product or service divided by the total number of shopping customers.

h. "Number of Participating Employees – General" - For costs of products and services driven by all participating employees within the FirstEnergy system, the allocation method that will be used will be the number of participating employees for the respective Subsidiary receiving the product or service divided by the total number of participating employees.

i. "Number of Participating Employees - Utility and Non-Utility" - For costs of products and services driven by participating employees who work for the Utility and Non-Utility Subsidiaries, the Subsidiaries receiving the product or service are first assigned a distribution ratio that is in proportion to the Indirect Costs based on FirstEnergy's equity investment in the respective groups. Costs are further allocated by using the number of participating employees for the respective Subsidiary divided by the total number of participating FirstEnergy employees.

j. "Gigabytes Used Ratio" - Number of gigabytes utilized by a Subsidiary receiving the product or service divided by the total number of gigabytes used by the FirstEnergy system companies applicable to that respective product or service.

k. "Number of Computer Workstations Ratio" - Number of computer workstations utilized by a Subsidiary receiving the product or service divided by the total number of computer workstations in use by the FirstEnergy system companies applicable to that respective product or service.

l. "Number of Billing Inserts Ratio" - Number of billing inserts performed for a Subsidiary receiving the product or service divided by the total number of billing inserts performed for the FirstEnergy system companies applicable to that respective product or service.

m. "Number of Invoices Ratio" - Number of invoices processed for a Subsidiary receiving the product or service divided by the total number of invoices processed for the FirstEnergy system companies applicable to that respective product or service.

n. "Number of Payments Ratio" - Number of monthly payments processed for a Subsidiary divided by the total monthly number of payments processed for the FirstEnergy system companies applicable to that respective product or service. This will not be utilized until some historical information is available out of our new automated system.

o. "Daily Print Volume" - Average daily print volume performed for a Subsidiary receiving the service divided by the total average daily print volume performed for the entire FirstEnergy system.

p. "Number of Intel Servers" - Number of Intel servers utilized by a Subsidiary receiving the product or service divided by the total number of Intel servers utilized by the FirstEnergy system.

q. "Application Development Ratio" - Number of application development hours budgeted for a Subsidiary receiving the service divided by the total number of budgeted application development hours for the year.

r. "Server Support Composite" - The average ratio of unix gigabytes, SAP gigabytes and Intel number of servers for a Subsidiary receiving the service.

3. Descriptions of Products and Services

CALL CENTER

Product or Service	Product / Service Description	Indirect Allocation Methods
Field All Inbound Regulated Calls	Field calls related to billing, credit, new service, service order completion, outages, and other miscellaneous activities.	Multiple Factor – Utility and Non-Utility
Field All Inbound Unregulated Calls	Field calls related to billing, credit, new service, service order completion, outages, and other miscellaneous activities.	Multiple Factor – Utility and Non-Utility

CUSTOMER SERVICE

Product or Service	Product / Service Description	Indirect Allocation Methods
Supplier Services	Provide customer services support to electric generation suppliers, administer and maintain Electronic Data Interface (EDI) functions and invoice suppliers.	Number of Shopping Customers Ratio
Regulatory Interface and Process Improvement: Supplier	Liaison to ensure Customer Choice requirements and develop and execute plans to improve supplier services processes.	Number of Shopping Customers Ratio
Market Support Generation (MSG) Administration	Administer and support MSG supplier functions.	Number of Shopping Customers Ratio
Regulatory Interface and Process Improvement: Regulatory	Respond to regulatory complaints from customers and develop and execute plans to improve regulatory compliance processes.	Number of Customers Ratio
Compliance	Work with regions to communicate and ensure regulatory requirements.	Multiple Factor – Utility
Power Billing	Provide billing functions for large commercial/industrial contract customers.	Number of Customers Ratio
Revenue Reporting	Perform and manage revenue reporting functions.	Number of Customers Ratio
Billing Exception Processing	Process billing exceptions.	Number of Customers Ratio
Remittance Processing	Process customer payments and deposit funds.	Number of Payments Ratio
Human Services	Coordinate and administer the various social services programs.	Number of Customers Ratio

Arrears Management/ Outsourcing Services Incorporated (OSI) Administration	Coordinate and perform arrears, credit and bankruptcy functions. Manage outside collections agencies' performance and OSI credit activities.	Number of Customers Ratio
Revenue Protection Administration	Perform revenue reporting and compliance functions.	Number of Customers Ratio
Metrics and Budget/ Customer Satisfaction Measurement	Manage Customer Services and Call Center Departments' budgets and measure performance and customer satisfaction results.	Number of Customers Ratio
Policy/Procedures Development and Documentation	Develop, document and communicate Customer Services policies and procedures.	Number of Customers Ratio
Bill Administration/ Forms Administration	Design standardized customer bills, envelopes, and forms.	Number of Customers Ratio
Meter Reading Support	Coordinate Meter Reading schedules and routing activities.	Number of Customers Ratio
Customer Information System (CIS) Control	Operate and maintain CIS.	Number of Customers Ratio

ECONOMIC DEVELOPMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Economic Development Services	Foster economic development to encourage capital investment in FirstEnergy's service areas.	Multiple Factor – Utility

TRANSMISSION & DISTRIBUTION TECHNICAL SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Forestry	Provide forestry services.	Multiple Factor – Utility
Distribution Reliability and Asset Records	Services include Joint User contracts, public works coordination, reliability reporting to regions and Public Utility Commissions, mutual assistance coordination, PowerOn support, cable locate ticket screening and tariff support.	Multiple Factor – Utility

Design Standards	Services include line material and construction standards, distribution line and underground maintenance practices and support, new business process support, and service practices.	Multiple Factor – Utility
Substation Services Support	Services include Substation maintenance plan coordination, practices and support, mobile substation administration and planning, and environmental compliance support.	Multiple Factor – Utility
Equipment Repair/Testing Services	Services include the maintenance, installation, maintenance, testing and repair of utility equipment.	Multiple Factor – Utility
Fleet Services	Develop fleet strategy, and perform fleet maintenance practices and support.	Multiple Factor – Utility
Financial Services	Identify revenue enhancements and cost reductions.	Multiple Factor – Utility
Substation Design and Transmission-Line Maintenance Support	Perform substation and transmission line design and project management and transmission line and substation design and material standards, right-of-way and survey services, transmission line maintenance plan coordination, practices and support, FAA activity coordination.	Multiple Factor – Utility
Planning and Protection	Perform planning and protection support for subtransmission system and overall radial system capacity planning overview, and interconnection coordination for distributed technology applications on distribution system.	Multiple Factor – Utility
Capital Budget and Equipment Support	Capital budget development and support, and major equipment specifications and procurement/repair activities for major equipment.	Multiple Factor – Utility

WORKFORCE DEVELOPMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Transmission and Distribution Skills Training	Develop and facilitate technical and safety training for workers associated with distribution activities, including line, substation, meter, fleet, warehouse, field engineering, and dispatch. Provide support through equipment evaluation, training analyses, job assessments, and project coordination.	Number of Participating Employees – General
Customer Service Skills Training	Develop and facilitate skills training for customer service groups.	Multiple Factor – Utility
External Learning Opportunities Through the Power Systems Institute	Develop educational partnerships with colleges to offer two-year degrees in electric utility technology.	Multiple Factor – Utility

ADMINISTRATIVE SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Administrative Support Services	Provides services in production printing, document imaging, graphic services, food services, corporate mailroom and corporate courier.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*
Provide Records Management Services	Provides services in records storage, records retrieval, records retention, records planning and engineering records.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*
Provide Business Services	Provides services in convenience copiers, fax machines, pagers, printers, and business information center.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*

* For services rendered only to the utilities.

EXECUTIVE

Product or Service	Product / Service Description	Indirect Allocation Methods
Executive Management	Consultation and services in management and administration of all aspects of the business.	Multiple Factor – All

COMMUNICATIONS

Product or Service	Product / Service Description	Indirect Allocation Methods
Public Relations	Provides services in media relations, financial communications, annual reports, executive presentation, public relations counsel, corporate writing, internet support and special projects.	Multiple Factor – All
Employee Communications	Provides services with update, retirees, satellite broadcast, human resource-related communications and special projects.	Number of Participating Employees – Utility and Non-Utility
Production	Provides services related to display, photography, Corporate ID, video and employee merchandise.	Multiple Factor – All
Sponsorship	Provides services related to sports marketing, university support and special projects.	Multiple Factor – All
Non-Utility Advertising	Provides services related to broadcast/print, collateral, direct mail, internet/intranet, display/merchandise, yellow/white pages, production/agency support and special projects.	Multiple Factor – Non-Utility
Utility Advertising	Provides services related to TV, radio, print, outdoors, Internet/Intranet, special projects, production, agency support and creative media placement.	Multiple Factor – Utility
Utility Bill Inserts	Provides services developing regulated bill service to Ohio, Pennsylvania and New Jersey.	Multiple Factor – Utility
Utility : Yellow / White Pages	Provides services with regulated yellow/white pages.	Multiple Factor – Utility
Utility: Research	Provides research services.	Multiple Factor – Utility
Ohio Consumer Education	Provides services related to Ohio Consumer Education statewide and locally.	Multiple Factor – Utility
Ohio Deregulation Education	Provides service related to Deregulation Education.	Multiple Factor – Utility

CORPORATE AFFAIRS AND COMMUNITY INVOLVEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Corporate Affairs Activities	Provide administrative support through oversight of the business practices and planning and implementation of staff, senior management and related meetings. Serves as community liaison.	Multiple Factor – Utility
Direct Community Involvement Initiatives	Provides direction in employee volunteerism, supports viable community partnerships and educational initiatives.	Multiple Factor – Utility
Energy Efficiency Programs	Directing and coordinating Ohio Weatherization and Energy Efficiency Programs for Low Income Customers.	Multiple Factor – Utility
Community Initiatives Consulting Services	Consults to regional operations and other business units and client managers for the various community programs.	Multiple Factor – Utility
Contributions Management	Directs, coordinates, monitors, and manages contributions.	Multiple Factor – Utility

CORPORATE

Product or Service	Product / Service Description	Indirect Allocation Methods
Investor Services	Stock administration, perform recordkeeping, transfer agent, registrar, paying agent, reinvestment plan administration and other services for shareholders.	None (All Direct Charge to Holding Co.)
Board of Directors Support	Support and administration of Board of Directors meetings and director compensation.	None (All Direct Charge to Holding Co.)
Annual Meeting Coordination	Coordinate the Annual Meeting of Shareholders, including the preparation and mailing of proxy materials and annual reports and the tabulation of proxies.	None (All Direct Charge to Holding Co.).
Indenture Compliance	Administer the company's indentures	Multiple Factor – Utility

HUMAN RESOURCES

Product or Service	Product / Service Description	Indirect Allocation Methods
Manage Employee Executive Compensation and Benefits	Provide management and supervision for employee and executive compensation and benefits.	Number of Participating Employees – General
Manage Workers Compensation and Disability Management	Provide management and supervision for workers compensation and disability programs.	Number of Participating Employees – General
Provide and Coordinate Human Resources Training	Design, prepare and conduct training.	Number of Participating Employees – General
Provide Employment Services	Provide staffing, relocation and employment expertise.	Number of Participating Employees – General
Provide HRIS Services.	Provide and maintain Human Resources information.	Number of Participating Employees – General
Provide Diversity Management Services	Manage Affirmative Action programs, provide EEO/AA consulting services, and respond to charges.	Number of Participating Employees – General
Manage/ Administer Medical Services and Wellness Programs	Establish compliance, develop, implement, and administer medical and wellness programs.	Number of Participating Employees – General

INDUSTRIAL RELATIONS

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Labor Contract Negotiations	Provide contract negotiation services for all labor agreements.	Number of Participating Employees – General
Provide Labor Consulting Services	Provide labor consulting services.	Number of Participating Employees – General
Manage/Administer Safety Programs	Develop, implement and administer occupational safety programs.	Number of Participating Employees – General

REAL ESTATE

Product or Service	Product / Service Description	Indirect Allocation Methods
Facilities Management	Management and maintenance of office facilities.	Multiple Factor – All or Multiple Factor Utility*
Facilities Planning and Project Management	Manage office design services, furniture, project management and other capital improvements.	Multiple Factor – All or Multiple Factor Utility*
Management of Real Estate Assets	Support internal and external inquiries regarding the acquisition, divestiture and management of real estate assets	Multiple Factor – All or Multiple Factor Utility*
Manage/Administer Security Programs	Administer physical security, special investigations, security audits, security consultation and contract guard services.	Multiple Factor – All or Multiple Factor Utility*

* For services rendered only to the utilities.

FIRSTENERGY TECHNOLOGIES

Product or Service	Product / Service Description	Indirect Allocation Methods
Strategic Technologies	Develop, support and implement EPRI programs, industry initiatives, research and development programs, collaboratives and activities with universities, labs and the Department of Energy.	Multiple Factor – Utility
New Technology Assessment	Perform assessment activities for strategic technology pilots, technology assessments, marketing tests, customer pilots and due diligence reviews.	Multiple Factor – Utility and Non-Utility
Technical Application and Product Innovation	Develop, analyze and support strategic alliances, joint ventures, strategic startups, direct investments and Portfolio initiatives.	Multiple Factor – Utility and Non-Utility
New Technology and Product Market Deployment	Develop, support and implement the following initiatives: tailored solutions with existing products, commercial packages, operational efficiencies and business area solutions.	Multiple Factor – Utility and Non-Utility
Demand Response Initiatives	Provide support for corporate demand response initiatives.	Multiple Factor – Utility and Non-Utility
Renewable Energy Program and Strategy	Provide support for various corporate and regulatory initiatives to develop and implement renewable energy programs and products.	Multiple Factor – Utility

Regulated Programs and Services	Develop, support and implement programs and strategies to meet corporate initiatives and regulatory mandates and commitments related to Comprehensive Resource Assessment(CRA), customer end-use. technology, distributed generation and load management.	Multiple Factor – Utility
Project Implementation Management Services	Develop and implement end-use and distributed generation technology-based products and services.	Multiple Factor – Utility and Non-Utility

TECHNOLOGY & SUPPORT SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Network Services	Provide Internal Network Services.	Multiple Factor – Utility and Non-Utility
Maintain wireless cell sites and fiber optics network	Maintain internal wireless cell sites and fiber optic network; provide engineering, procurement, and installation services.	Multiple Factor – Utility and Non-Utility

INFORMATION TECHNOLOGY

Product or Service	Product / Service Description	Indirect Allocation Methods
Application Development	Create new or enhance existing applications; including analysis design coding, testing, system integration, and implementation, as well as any required technical writing or project manual development.	Directly Billed
Development Supervision and Tool Support	Supervision of application development employees and the support of development software tools.	Application Development Ratio
Server Support (Unix, SAP)	Create and support the network and server infrastructure to accommodate unix and SAP client server applications.	Gigabytes Used Ratio
Client Server Storage Support	Support of storage requirements for all server applications.	Server Support Composite Ratio
Server Support (Intel)	Create and support the network and server infrastructure to accommodate windows and NT client server applications.	Number of Intel Servers Ratio
Mainframe Processing and Storage Support	Execute mainframe applications, including an appropriate portion of support, started tasks, mainframe backups and microfiche services.	Gigabytes Used Ratio

Desktop Support	Help desk email and end-user tools, remote access, repair services, and general workstation support.	Number of Computer Workstations Ratio
Network Services	Includes voice, data, EMS and radio access.	Direct Charge Ratio
Inserting Services	Provide document bursting, inserting and mailing.	Number of Billing Inserts Ratio
Printing Services	Provide mainframe and client server printing services at the data center.	Daily Print Volume Ratio
Technical Consulting	Provide consulting support to departments and end-users to enable them to leverage their IT capabilities. Provide advice and consultation regarding desktop setups and configurations.	Directly Billed
Training	Provide IT training.	Multiple Factor – Utility and Non-Utility
Business Application Support	Support business application related software licenses and / or hardware maintenance provided by an outside vendor.	Directly Billed
Data Security	Disaster recovery and data security services.	Multiple Factor – Utility and Non-Utility
Project Management Office	Oversee technology projects through benefit.	Multiple Factor – Utility and Non-Utility
Provide Telecommunication Services	Provide telecommunication services and equipment.	Direct Charge Ratio
Portal Support	Support the infrastructure to accommodate internet and infranet application access.	Multiple Factor – Utility and Non-Utility

PERFORMANCE PLANNING

Product or Service	Product / Service Description	Indirect Allocation Methods
Performance Planning Services	Develop, support and execute performance planning services.	Multiple Factor – All

SUPPLY CHAIN

Product or Service	Product / Service Description	Indirect Allocation Methods
Strategic Planning, Demand management and Procurement Projects	Provide assistance in materials and services planning (demand management) and performs special procurement projects.	Multiple Factor – Utility and Non-Utility
Goods and services procurement	Procure material, equipment and contractor services. Establish, manage and administer programs, which allow internal customers to obtain goods without having to process the need through Procurement. Develop specifications, construction standards, schedules, and bills of materials.	Multiple Factor – Utility and Non-Utility
Materials Management Support	Maintain the computerized purchasing and materials management systems, and material related modules; maintain and/or modify select management reports. Analyze Supply Chain processes and measure performance. Monitor and forecast demand to ensure a continuous supply of materials.	Multiple Factor – Utility and Non-Utility
Investment Recovery Projects	Develop and implement plans for disposition of surplus assets.	Multiple Factor – Utility and Non-Utility
Process, Refurbish and Sell Materials	Perform recovery processing, investment recovery processing, refurbishing and selling materials.	Multiple Factor – Utility and Non-Utility
Provide Warehousing Services - Non-nuclear	Receive and place material into stock, insure quality requirements are met at receipt, maintain inventory counts, and update information systems. Fill customer requests for material from stock.	Multiple Factor – Utility and Non-Utility
Provide Warehousing Services - Nuclear	Receive and place material into stock, insure quality requirements are met at receipt, maintain inventory counts, and update information systems. Fill customer requests for material from stock.	None (All direct charged)
Warehousing Space Charge	Provide warehousing space to internal customers.	Multiple Factor – Utility and Non-Utility

CONTROLLERS

Product or Service	Product / Service Description	Indirect Allocation Methods
Accounting Research	Provide accounting research and consulting to ensure compliance with existing and proposed financial reporting, and regulatory accounting requirements.	Multiple Factor - All
Accounts Payable	Nonpayroll corporate disbursement services including account distribution to the general ledger. Resolve problems associated with invoice processing and maintain the accounts payable system.	Multiple Factor - All
Billing Services	Prepare non-retail electric billings.	Multiple Factor Utility
Infrastructure and Corporate Reporting, Accounting and Budgeting	Prepare Corporate Sustaining reports, subsidiary accounting and corporate budgeting, which includes reporting and support of the ledger, property records and SAP system.	Multiple Factor - All
Due Diligence	Assist value centers to determine whether proposed business acquisitions/combinations and similar transactions are desirable from a financial perspective; extensive review/analysis following preliminary review and firm intent to proceed with transaction through commitment and closing phases.	None (All direct charged)
Value Center Accounting and Budgeting	Maintain the property accounting system and provide value center accounting such as management reporting.	Multiple Factor – Utility and Non-Utility
Property Record Maintenance	Maintain corporate continuing property records.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*
Tax Consulting and Research	Conduct tax research and tax consulting to assure compliance with statues, while evaluating alternative tax strategies within the constraints of regulations that provide additional shareholder value to the company. In addition, provide tax-consulting advice to the value centers on tax compliance and reporting issues, which includes business "start-up" support to organizations requiring assistance.	Multiple Factor – All

* For services rendered only to the utilities.

Tax Compliance	Prepare and process all schedules and information associated with corporate and subsidiary tax returns, audits, and tax litigation, assuring compliance with tax regulations and statues.	Multiple Factor – All or Multiple Factor Utility*

* For services rendered only to the utilities.

CREDIT MANAGEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Credit Analysis and Supporting Functions	Provide detailed written credit analysis issuing recommendations on counterparty creditworthiness and assigning credit limits.	Multiple Factor – Utility and Non-Utility
Credit Policies and Procedures	Develop and support credit policies and procedures for managing credit risk. Implement and support standardized credit approval processes.	Multiple Factor – Utility and Non-Utility
Credit Management Information System	Develop and support credit management reports and calculate credit exposure on a corporate wide basis.	Multiple Factor - All

ENTERPRISE RISK MANAGEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
General Risk Management	Develop and maintain an enterprise risk management system.	Multiple Factor - All

INSURANCE SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Insurance Policies	Manage and support insurance policies for all the business units .	Multiple Factor – Utility and Non-Utility
Loss Control Services	Manage and support property inspections to prevent losses.	Multiple Factor – Utility and Non-Utility
Surety Bonds	Manage and support Surety Bonds.	Multiple Factor – Utility and Non-Utility
Risk Transfer and Risk Mitigation Services	Manage and support risk transfer and risk mitigation services.	Multiple Factor – Utility and Non-Utility
Ancillary Coverages	Manage and support ancillary coverages.	None (All direct charged)

INTERNAL AUDIT

Product or Service	Product / Service Description	Indirect Allocation Methods
Audit Services	Perform the following internal audit services based on risk levels and / or requests: financial, performance analysis, safeguarding of assets, computer- related and fraud investigations.	Multiple Factor – All or Multiple Factor – Utility*

INVESTMENT MANAGEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Qualified and Non-qualified Pension and Savings Plan	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Number of Participating Employees – Utility and Non–Utility
FirstEnergy Foundation	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Multiple Factor - All
Voluntary Employee Benefit Association (VEBA) Trust	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Number of Participating Employees – Utility and Non–Utility
Nuclear Decommissioning	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	None (All direct charged)
Non-Utility Generator Trust	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Multiple Factor – Non-Utility
Spent Nuclear Fuel	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	None (All direct charged)
Low-Income Housing Tax Credit Partnership	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Multiple Factor - All

INVESTOR RELATIONS

Product or Service	Product / Service Description	Indirect Allocation Methods
Investor Information	Compile and communicate information to investors.	Multiple Factor – Utility* or Direct Charge to Holding Co.
Investor Education	Target and educate potential investors to promote FirstEnergy's valuation characteristics and business strategy.	None (All Direct Charge to Holding Co.)

* For services rendered only to the utilities.

Regulations Compliance	Ensure compliance with SEC Fair Disclosure regulations.	Multiple Factor - All

FirstEnergy Management Education	Provide education to management of business concerns and valuation issues of analyst/investors	Multiple Factor – All
FirstEnergy Employee Education	Actively promote understanding of financial and investor relations' issues.	Multiple Factor – All

RATES AND REGULATORY AFFAIRS

Product or Service	Product / Service Description	Indirect Allocation Methods
Regulatory Activities and Consulting	Manage regulatory activities and interfaces, including tariff development and interpretation. Monitor and participate in regulatory affairs at the local, state and federal levels.	Multiple Factor – Utility
Customer Pricing and Contracting	Develop pricing programs for regulated electric service for retail and wholesale customers, including "unbundled" costs and prices for generation, transmission and distribution service and support justification to regulators. Provide support in developing pricing for special-purpose customer programs and non-regulated energy services (e.g. prepayment, economic development, interruptible load, conjunctive-billing electric service programs).	Multiple Factor – Utility
Billing Support	Provide assistance calculating customer (external and internal) invoices and operate and maintain systems to render, collect and account for these invoices.	Multiple Factor – Utility
Sales and Load Forecasting	Develop short-term and long-term sales forecast, peak load projections and customer counts	Multiple Factor – Utility and Non-Utility

TREASURY

Product or Service	Product / Service Description	Indirect Allocation Methods
Capital Structure Management and Administration	Perform all activities related to acquiring capital and establish and administer funding, legal documentation, and record-keeping activities associated with finance programs	Multiple Factor – All
Corporate Funds Management	Plan, manage, and operate the corporate "cash-flow-cycle."	Multiple Factor – All
Corporate Forecasting	Provide regulatory support, strategy support, financial modeling and forecasting, financial and economic analysis and development of annual corporate KPI target.	Multiple Factor – All

Capital Project Evaluation and Support	Provide analytical support in the areas of financing, profitability, capital structure and cash flow.	Multiple Factor – Utility and Non-Utility
Investor Relations Activities	Provide institutional and retail security holder, buy and sell-side analysts, rating agencies, and other key members of the financial community with qualitative and quantitative information.	Multiple Factor – All

BUSINESS DEVELOPMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Mergers and Acquisitions Support	Support, evaluate and assist in the management of merger, asset acquisition and asset disposition activities.	None (All direct charged)
Internal Consulting	Perform strategic analysis/business fit, and economic analysis. Provide integration and transitional management services as needed.	None (All direct charged)

GOVERNMENTAL AFFAIRS

Product or Service	Product / Service Description	Indirect Allocation Methods
Federal Governmental Affairs Support	Activities associated with developing and maintaining relationships with federal government institutions; includes lobbying, and other support activities.	None (All direct charged)
State Governmental Affairs Support	Activities associated with developing and maintaining relationships with state government institutions; includes lobbying, and other support activities.	None (All direct charged)

LEGAL

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Governmental Affairs Support	Activities associated with developing and maintaining relationships with government institutions; includes lobbying, litigation, and other support activities.	None (All direct charged)
Nuclear Legal Consultation and Case Management	Provide legal advice for federal and state nuclear matters.	None (All direct charged)
Human Resources Legal Consultation & Case Management	Provide legal advice for human resource matters (including workers compensation, union negotiations, arbitrations, class action lawsuits, etc.).	Multiple Factor – Utility and Non-Utility

Product or Service	Product / Service Description	Indirect Allocation Methods
Employee Benefits Legal Consultation & Case Management	Provide legal advice for employee benefits matters (including health and welfare benefits, tax-qualified and non-tax qualified benefit plans and programs, pension administration, etc.).	Number of Participating Employees – Utility and Non-Utility
Tax Legal Consultation & Case Management	Provide legal advice for tax matters including federal, state & local tax matters (land tax, sales & use tax, IRS, etc.).	Multiple Factor – All
Bankruptcy Legal Consultation & Case Management	Provide legal advice for bankruptcy matters.	Multiple Factor – Utility and Non-Utility
International Legal Consultation & Case Management	Provide legal advice for international matters– contract negotiations, sale/lease agreements.	None (All direct charged)
Non-Utility Legal Consultation & Case Management	Provide legal advice on federal and state matters to Non-Utility Subsidiaries.	Multiple Factor – Non-Utilities
Regulatory Legal Consultation & Case Management	Provide legal advice for federal and state regulatory matters.	Multiple Factor – Utility
Environmental Legal Consultation & Case Management	Provide legal advice for environmental matters (other than PCB – related matters) - federal (EPA) and state (EPA), regulatory/legislative compliance issues.	None (All direct charged)
PCB Environmental Legal Consultation & Case Management	Provide legal advice for PCB-related matters - federal (EPA) and state (EPA), regulatory/legislative compliance issues.	Multiple Factor – Utility
Real Estate Legal Consultation & Case Management	Provide legal advice for real estate matters.	Multiple Factor – Utility and Non-Utility
Corporate Legal Consultation & Case Management	Provide legal advice for general corporate and transactional matters (including SEC filings, Board of Directors matters, PUHCA, Financings, Securities Matters, Intellectual Property, Technology, General Counsel matters, etc.).	Multiple Factor – All
Claims Legal Consultation & Case Management	Provide legal advice for Claims matters.	Multiple Factor – All

CLAIMS

Product or Service	Product / Service Description	Indirect Allocation Methods

Process Receivable Claims	Provide management, supervision, and performance of tasks associated with the resolution and chargeback of receivable claims.	Multiple Factor - All
Provide Corporate Support	Claims support in evaluating claims, and procuring appropriate external/internal legal resources.	Multiple Factor - All

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-8:

"Provide an analysis by function of charges by affiliates, for the test year and the 12-month period immediately prior to the test year, for services rendered included in the operating expenses of the filing company. Explain the nature of the service and the basis on which charges or allocations are made, including a copy of an applicable contract. Also, explain major variances between the charges for the test year and the corresponding charges for the prior 12-month period."

RESPONSE:

See Met-Ed Exhibit RAD-25 Attachment A for a summary of charges budgeted to be billed to Met-Ed by First Energy Service Company for the twelve months ending April 30, 2016 and the 12 months ending March 31, 2015. Met-Ed Exhibit RAD-25 Attachment A also shows the charges billed to Met-Ed by First Energy Service Company for the twelve months ended March 31, 2014.

Also included is a copy of the Service Agreement between the operating subsidiary Metropolitan Edison Company and FirstEnergy Service Company (FE Service) outlining the services to be provided by FE Service and the basis on which charges are to be billed. See Met-Ed Exhibit RAD-25 Attachment B.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-9:

"Prepare a detailed schedule for the test year showing types of social and service organization memberships paid for, the cost thereof, the accounting treatment and whether included in claimed test year expenses."

RESPONSE:

Metropolitan Edison Company
Social and Service Organization Memberships Paid
(000's)

Line No.	Organization	12 Months Ending April 30, 2016 (1)	March 31, 2015 (2)	March 31, 2014 (3)
	Business Associations			
	Account 930			
1	Edison Electric Institute	$ 132	$ 132	$ 116
2	Chamber of Commerce, Economic Development, & Local Community Organizations	40	40	27
3	Southeastern Electric Exchange Inc.			4
4	Other Business / Trade Organizations	3	3	
5	Total Account 930.20	$ 175	$ 175	$ 147
	Account 923			
6	Southeastern Electric Exchange Inc.	-	-	4
		$ -	$ -	$ 4
	Account 426			
7	Edison Electric Institute	31	31	33
		$ 31	$ 31	$ 33
8	Total (line 5 + line 6 + line 7)	$ 206	$ 206	$ 184

Metropolitan Edison Company (Met-Ed)

Payroll and Employee Benefits
($000)

Line No.	Description	12 Months Ending 4/30/2016 Full-Time Bargaining	12 Months Ending 4/30/2016 Full-Time NonBargaining	12 Months Ending 4/30/2016 Total	12 Months Ending 3/31/2015 Full-Time Bargaining	12 Months Ending 3/31/2015 Full-Time NonBargaining	12 Months Ending 3/31/2015 Total	12 Months Ending 3/31/2014 Full-Time Bargaining	12 Months Ending 3/31/2014 Full-Time NonBargaining	12 Months Ending 3/31/2014 Total
	Number of Employees									
1	Average	467	164	631	469	165	634	491	162	653
2	Year-End	467	164	631	467	164	631	485	152	637
3	Straight Time Payroll	$ 36,777	$ 15,679	$ 52,455	$ 35,333	$ 15,043	$ 50,377	$ 33,939	$ 14,583	$ 48,522
4	Overtime Payroll	5,432	774	6,206	5,987	780	6,767	10,068	1,691	11,759
5	Incentive Compensation	1,629	887	2,516	1,706	912	2,618	2,654	2,003	4,657
6	Total Payroll	$ 43,838	$ 17,339	$ 61,177	$ 43,026	$ 16,735	$ 59,762	$ 46,660	$ 18,277	$ 64,937
	Total Company Employee Benefits:									
7	Workers Compensation	$ 317	$ 111	$ 428	$ 317	$ 111	$ 428	$ 310	$ 109	$ 419
8	Pension Costs	(3,303)	(1,160)	(4,463)	(3,833)	(1,348)	(5,181)	(9,172)	(3,221)	(12,392)
9	OPEB	(3,661)	(1,286)	(4,946)	(8,713)	(3,064)	(11,777)	(16,340)	(5,738)	(22,078)
10	Life Insurance	68	24	91	73	26	99	31	11	42
11	Medical/Dental Insurance	4,285	1,505	5,790	4,015	1,412	5,427	4,525	1,589	6,114
12	Executive Benefits	0	660	660	0	636	636	0	(406)	(406)
13	Restricted Stock	0	121	121	0	117	117	0	136	136
14	Savings Plan	2,090	734	2,824	1,657	583	2,240	979	344	1,323
15	Long Term Disability	119	42	161	119	42	161	43	15	57
16	Education Assistance	45	16	60	49	17	67	16	6	21
17	Employee Awards	5	2	7	5	2	7	0	0	0
18	Employee Assistance Program	9	3	12	9	3	12	9	3	12
19	Wellness Program	170	60	230	156	55	211	71	25	96
20	Relocation	0	322	322	0	351	351	0	790	790
21	Other	14	5	19	16	6	22	43	15	58
22	Total Employee Benefits	$ 158	$ 1,159	$ 1,317	$ (6,129)	$ (1,052)	$ (7,181)	$ (19,485)	$ (6,323)	$ (25,808)

(1) Employee Counts exclude Part-time and Temporary employees
(2) Benefit costs allocated to Bargaining/NonBargaining based on average number of employees
except for Executive Benefits, Restricted Stock and Relocation expenses (100% non-bargaining)

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-11:

"Describe costs relative to leasing equipment, including computer rentals, and office space, including terms and conditions of the leases. State method for calculating monthly or annual payments."

RESPONSE:

Line No.	Name of Lessor	Basic Detail of Lease	12 Months Ended April 30, 2016 *(In thousands)*
1	GE Capital Commercial Inc. (successor-in-interest to BLC Corporation)	Motor Vehicles & Trailers – Base term 36-120 months with fixed rate & maximum expected residual of 25% and unguaranteed residual of 13%. At end of base term, option for renewal exists for up to 24 months at 474 BPS plus federal 2 year swap rate. At end of renewal term, option to continue to rent for monthly fee equivalent of 1/12 of 1% of acquisition cost until unit is sold or returned to Lessor. Other Equipment – Base term of 36-120 months with a fixed rate & maximum expected residual of 20% with unguaranteed residual of 13%. At end of base term, option for renewal exists for up to 24 months at 474 BPS plus federal 2 year swap rate. At end of renewal term, option to continue to rent for monthly fee equivalent of 1/12 of 1% of acquisition cost until unit is sold or returned to Lessor.	$955

2	RBS Asset Finance, Inc.	Motor Vehicles & Trailers – Base term 60 months for light and medium duty vehicles, 96 months for heavy duty high use trouble trucks and 120 months for all other heavy duty vehicles & trailers with a $1 buy out at end of term for all. Other Equipment – Base term 96 months for miscellaneous equipment like ATVs, sweeper/scrubbers, etc. and 120 months for construction equipment & forklifts with a $1 buy out at end of term for all. Rates for both motor vehicles/trailers & other equipment leases are fixed based on 200 BPS plus Bloomberg Avg Life swap rate (2.5 years for 60 month term, 4 years for 96 month term and 5.5 years for 120 month term).	$3,642

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-12:

"Submit a statement of past and anticipated changes, since the previous rate case, in major accounting procedures, explain any differences between the basis or procedure used in allocations of revenues, expenses, depreciation and taxes in the current rate case and that used in the prior rate cases, and list all internal and independent audit reports for the most recent 2 year period."

RESPONSE:

A list of all internal audit reports performed by the Internal Audit Department from April 2012 through March 2014 appears on pages 3 through 6.

A list of all independent audits performed from April 2012 thru March 2014 appears on page 6.

The following is a list of major changes in accounting procedures adopted since the previous rate case:

1. In 2006, the Company adopted SFAS 158 (ASC 715), *Accounting for Defined Benefits.* This statement requires employers to recognize an asset or liability for the overfunded or underfunded status of their pension and other postretirement benefit plans (OPEB). For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. The Statement required employers to recognize all unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive income (AOCI), net of tax. Such amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost or income pursuant to the current recognition and amortization provisions.

2. In 2007, the Company adopted FIN 48, *Accounting for Uncertainly in Income Taxes,* which provides guidance for accounting for uncertainty in income taxes in a company's financial statements in accordance with SFAS 109 (ASC 740), *Accounting for Income Taxes.* This interpretation prescribes a financial statement recognition threshold and measurement attribute for tax positions taken or

expected to be taken on a company's tax return. FIN 48 also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation is a two-step process. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination, based on the merits of the position, and should therefore be recognized. The second step is to measure a tax position that meets the more likely than not recognition threshold to determine the amount of income tax benefit to recognize in the financial statements.

FIN 48 also requires companies to recognize interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized in accordance with FIN 48 and the amount previously taken or expected to be taken on the tax return. The Company includes net interest and penalties in the provision for income taxes, consistent with its policy prior to implementing FIN 48.

3. In 2011, the Company changed its method of recognizing actuarial gains and losses for its defined benefit pension and OPEB plans. Previously, the Company recognized the net actuarial gains and losses as a component of AOCI and amortized the gains and losses into income over future periods.

   The Company, with this accounting change, elected to immediately recognize the change in fair value of plan assets and actuarial gains and losses annually in the fourth quarter of each year. The Company retroactively applied immediate recognition of gains and losses for its defined benefit pension and OPEB plans to each year, from 1986 through 2010.

Internal Audits Performed During – April through December 31, 2012

Compliance:

1. Audit of the IBM Consulting Services' Pennsylvania "Smart Meter Implementation and Procurement" Plan Development as of February 10, 2012
2. Limited Scope Review of US Bank Travel Card as of July 27, 2012
3. Audit of Substation Safety/Security Inspection and Corrective Maintenance as of October 3, 2012
4. Review of Purchasing Card Usage – Severed Employees as of December 12, 2012
5. Audit of Met-Ed Energy Delivery Inspection & Maintenance Programs as of November 26, 2012
6. 2012 Corporate Compliance Program Update
7. Annual Review of the Code of Business Conduct as of November 26, 2012

Operational:

1. Audit of the Streetlight Repair Process as of May 2, 2012
2. Data Analysis of Wood Pole Inspection Results (Years 2007-2011) as of October 8, 2012
3. Audit of Rate Change and Rate Adjustment Processes Documentation as of September 17, 2012
4. Energy Efficiency Program Support (Memorandum)

IT Related:

1. Audit of IT Merger Project - Consolidate IT Security Policies (L01) as of March 16, 2012
2. Audit of IT Merger Project - Energy Delivery Meter and Transformer Testing Systems (B07.1) as of February 27, 2012
3. Audit of IT Merge Project - Energy Delivery Graphical Information System (B02.3) as of March 23, 2012
4. Audit of IT Merger Project - Energy Delivery Outage Management Ancillary (B01.2) as of April 13, 2012
5. Audit of IT Merger Project - Energy Delivery Internet Vegetation Management System (B06.1) as of May 7, 2012
6. Audit of IT Merger Project - Cascade (B02.1) as of May 11, 2012
7. Audit of IT Merger Project - Energy Delivery Meter Reading and Route Completion (B07.2) as of May 18, 2012
8. Audit of IT Merger Project - Energy Efficiency & Conservation/Demand Response Program Integration (C03.1) as of May 11, 2012
9. Audit of IT Merger Project - Energy Delivery Outage Management (B01.1) as of May 11, 2012
10. Audit of IT Merger Project - Consolidate Sensitive Customer Information Programs (L01) as of May 21, 2012
11. Audit of IT Merger Project - SAP Project Light-year as of May14, 2012
12. Audit of IT Merger Project - Contact Center Technologies as of June 25, 2012
13. Audit of IT Merger Project - Energy Delivery Work Management System (B04.2) as of June 12, 2012
14. Audit of IT Merger Project - Rates/Load Forecasting System (B08.1) as of April 2, 2012

15. Audit of IT Merger Project - Consolidate eDiscovery and Record Retention Processes (L01.1) as of October 31, 2012

Financial:

1. Audit of the Pennsylvania Energy Efficiency Conservation Service Provider Invoice Validation Guidelines as of January 31, 2012
2. Audit of Hurricane Irene Actual Charges as of May 11, 2012
3. Audit of the October 2011 Snowstorm Actual Charges as of May 11, 2012
4. Reconciliation of Advanced Billing Platform System Data to Electric Distribution Company Data as of July 8, 2012
5. Audit of Regulated Metered But Unbilled Revenue as of September 27, 2012
6. Sarbanes-Oxley Annual Progress Report as of December 28, 2012
7. First Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of March 31, 2012
8. Second Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of June 30, 2012
9. Third Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of September 30, 2012
10. Sarbanes-Oxley Annual Progress Report as of December 28, 2012

Internal Audits Performed During – January through December 31. 2013

Compliance:

1. Audit of 2012 Occupational Safety & Health Administration (OSHA) Recordable Incident Rate as of January 15, 2013
2. Audit Pennsylvania Distribution Vegetation Maintenance Practices as of January 15, 2013 - Privileged and Confidential - Prepared at the Request of Counsel
3. Audit of FirstEnergy's Compliance With Section 114 of the Fair and Accurate Credit Transactions Act as of March 31, 2013
4. Audit of Contract Compliance of Osmose Utilities Services, Inc., as of September 24, 2013
5. Interim Report of the Pre-Implementation Audit of the State Code of Conduct Project as of December 6, 2013
6. 2013 Corporate Compliance Program Update
7. Annual Review of the Code of Business Conduct as of November 27, 2013

Operational:

1. Audit of Energy Delivery Joint Use Revenue as of October 26, 2012
2. Audit of the Implementation of Energy Delivery's Resources on-Demand Application as of November 4, 2013
3. Request for Guidance on Inflated Labor Rates for Diversified Services - Hurricane Sandy – Memorandum
4. Internal Auditing's Partnering Engagement in Documenting Regulated Settlements' Processes and High Risk Procedures

5. Internal Auditing Risk Assessment - Smart Meter Implementation Procurement (SMIP) Project

IT Related:

1. Interim Memorandum - Facilitation of the Control Design for the Office Productivity Transformation Project
2. Interim Report of the Pre-Implementation Audit of the Financial Transformation Project Budget, Forecast, and Planning System as of August 16, 2013
3. Audit of the Cascade Order Integration Project as of June 25, 2013
4. Office Productivity Transformation Testing and Pilot Project
5. Interim Report of the Pre-Implementation Audit of the Financial Transformation Project -
   New General Ledger Technology as of December 6, 2013
6. Interim Report of the Pre-Implementation Audit of the Financial Transformation Project -Business Objects Planning and Consolidation System as of December 6, 2013
7. PowerPlant Continuous Improvement Project

Financial:

1. Audit of FirstEnergy Utilities' Capital and Operation & Maintenance Expenses as of January 31, 2013
2. Audit of the PA Top 100 Hours Demand Response Program Invoicing Process as of February 13, 2013
3. Audit of Transmission Control Center Affiliate Rent Calculation as of July 12, 2013
4. Audit of the Smart Meter Tracking, Accounting and Cost Allocations Process as of November 7, 2013
5. Audit of the 2012 SOx 404 Assessment of Internal Controls as of December 31, 2012
6. First Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of March 31, 2013
7. Second Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of June 30, 2013
8. Third Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of September 30, 2013
9. Audit of the Purchasing Card Automated Reconciliation and Travel Expenses Implementation as of February 28, 2013
10. Vendor Payroll Tax Reconciliation Audit Review

Internal Audits Performed During – January through March 31, 2014

Compliance:

1. Audit of FirstEnergy Utilities Waste Management Practices as of November 7, 2013
2. Audit of FirstEnergy's Compliance to the Clean Air Act – Sulfur Hexafluoride Mandatory Emissions Tracking and Reporting as of January 21, 2014

Operational:

1. Audit of 2013 Occupational Safety & Health Administration (OSHA) Recordable Incident Rate as of January 10, 2014

IT Related:

1. IT Merger Support - EMS Auxiliary (F01.3)

Financial:

1. Revenew's Payment Recovery Audit for Accounts Payable – 2012
2. Sarbanes-Oxley Annual Progress Report as of December 31, 2013
3. Audit of Pennsylvania Storm Deferral Accounting as of January 14, 2014
4. Sarbanes-Oxley 404 Assessment of Internal Controls Over Financial Reporting as of December 31, 2013
5. Sarbanes-Oxley Annual Progress Report as of December 31, 2013

Independent Audits Performed for the years ended December 31, 2012 and 2013

PricewaterhouseCoopers LLP – Independent Registered Public Accounting Firm

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-13:

"Regardless of whether a claim for negative or positive net salvage is made, attach an exhibit showing gross salvage, cost of removal, third party reimbursements, if any, and net salvage for the test year and 4 previous years."

RESPONSE:

See Met-Ed Exhibit RAD-30 Attachment A

Metropolitan Edison Company
Third Party Reimbursement, Cost of Removal and Salvage

	Third Party Reimbursements (1)	Cost of Removal (2)	Salvage (3)	Net Salvage (4) = (2) + (3)
4/1/2009 thru 3/31/2010	(2,715,469)	17,818,561	(279,964)	17,538,597
4/1/2010 thru 3/31/2011	(2,572,758)	7,831,448	(730,293)	7,101,155
4/1/2011 thru 3/31/2012	(3,974,692)	17,901,617	(390,755)	17,510,862
4/1/2012 thru 3/31/2013	(5,356,002)	28,776,865	(529,057)	28,247,808
4/1/2013 thru 3/31/2014	(4,309,509)	10,625,421	(403,515)	10,221,906
4/1/2014 thru 3/31/2015	(6,676,242)	4,452,739	-	4,452,739
5/1/2015 thru 4/30/2016	(3,687,498)	4,509,478	-	4,509,478

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-14:

"State the amount of debt interest utilized for test year income tax calculations, including the amount so utilized which has been allocated from the debt interest of an affiliate, and provide details of debt interest and allocation computations."

RESPONSE:

Debt interest utilized in the normalized test year under present rates is $36,822,000 as calculated in Met-Ed Exhibit RAD-2, Adjustment No. 11 page 27.

METROPOLTAN EDISON COMPANY

FILING REQUIREMENT II-D-15:

"Provide a schedule for the test year of Federal and Pennsylvania taxes other than income taxes, per books, pro forma at present rates, and pro forma at proposed rates, including the following tax categories:

(a) Social Security.
(b) Unemployment.
(c) Capital stock.
(d) Public utility
(e) P.U.C. assessment.
(f) Other property taxes.
(g) Any other appropriate tax categories."

RESPONSE:

See Met-Ed Exhibit RAD-32 Attachment A for a schedule of taxes other than income taxes showing per budget and pro forma at present rates for the future test year.

Metropolitan Edison Company
Summary of Taxes other than Income Taxes
Twelve Months Ending April 30, 2016
($000)

Line No.	Description	Per Budget Total Electric Operating (1)	Pro Forma Under Present Rates Normalizing Adjustments (2)	As Adjusted (3)
	Federal			
1	Federal and State payroll taxes	$ 4,694	$ 490	$ 4,204
	State			
2	Capital Stock	149	33	116
3	Gross Receipts	38,732	-	38,732
4	Public utility realty	1,976	441	1,535
5	Gross premiums	-	-	-
6	Use tax	113	-	113
	Local			
7	Real estate & other	131	29	102
8	TOTAL	$ 45,795	$ 993	$ 44,802

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-16:

> "Submit a schedule showing the adjustments from taxable net income per books to taxable net income pro forma under existing rates and pro forma under proposed rates, together with an explanation of all normalizing adjustments. Submit detailed calculations supporting taxable income before State and Federal income taxes where the income tax is subject to allocation due to operations in another state or due to operation of other taxable utility or non-utility business, or by operating divisions or areas."

RESPONSE:

See Met-Ed Exhibit RAD-33 Attachment A.

Line No.	Description	In Thousands Fully Future Test Year Ending 4/30/16 Per Budget (1)	Pro-Forma Test Year Under Existing Rates (2)	Pro-Forma Test Year Under Proposed Rates (3)
1	Balance after preferred stock dividends	$ -		
	Net utility operating income:			
2	Exhibit RAD-2, page 1, line 23, column 13	$59,277	$ 29,730	
3	Exhibit RAD-2, page 3, line 23, column 33			$ 113,767
	Add:			
4	Income Taxes-Federal	29,037	19,923	65,173
5	Income Taxes-State	10,182	6,318	20,667
6	Provision for Deferred Income Taxes	7,347	3,598	3,598
7	Provision for Deferred Income Taxes-Credit	(1,011)	-	-
8	Investment Tax Credit	(364)	(283)	(283)
9	Book Income Subject to Tax	$ 104,468	$ 59,286	$ 202,922
	Adjustments:			
10	Book Depreciation	59,938	63,640	63,640
11	Tax Depreciation	(58,244)	(62,848)	(62,848)
12	Interest expense per Ratemaking	-	36,822	36,822
13	Business Meals	70		70
14	Life Insurance	(82)		(82)
15	NJ Min Tax	(2)		(2)
16	ESOP Dividend	(196)		(196)
17	Lobbying	31		31
18	Capitalized Interest-Avoided Costs in Excess of AFC	-		-
19	FAS 123R - Restricted Stock Units	-		-
20	FAS 143	-		-
21	Price to Compare Rider	7,483		7,483
22	ESOP Compensation Expense	-		-
23	Storm Damage & Other Deferrals	22,738		22,738
24	Deferrals / Amort SEIA			-
25	OPEBs	(2,549)		(2,549)
26	Tax Capitalized Interest	802		802
27	Reacquired Debt - Book Amortization of Loss	1,118		1,118
28	Casualty Loss	(17,909)		(17,909)
29	Section 263	(5,023)		(5,023)
30	T&D Repairs	(20,002)		(20,002)
31	AFUDC Equity	(1,343)		(1,343)
32	Capitalized Interest-Book AFC	(892)		(892)
33	PA PTC Deferral	7,483		7,483
34	Pension Accrual	(3,253)		(3,253)

Line No.	Description	In Thousands Fully Future Test Year Ending 4/30/16 Per Budget (1)	Pro-Forma Test Year Under Existing Rates (2)	Pro-Forma Test Year Under Proposed Rates (3)
35	Research & Development - 174	(415)		(415)
36	Asset Retirement Obligation	49		49
37	Capital Lease Vehicle - Book Expense	745		745
38	Universal Service Program (incl interest)	6,265		6,265
39	Other Reg Assets / Liabilities	(5,979)		(5,979)
40	CIAC - Post 86	-		-
41	State Taxable Income before Tax Preferences	$ 95,301 0	$ 96,900	$ 229,675
42	State Tax Preference Items	-	-	-
43	State Taxable Income	$ 95,301	$ 96,900	$ 229,675
	State Income Tax:			
44	Current Year	10,182	9,680	22,945
45	Total State Tax	$ 10,182	$ 9,680	$ 22,945
46	Less: State Tax Preference Items	-		-
47	Federal Taxable Income (Line 40-L42-L43)	$ 85,119	$ 87,220	$ 206,730

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-17:

"Submit a schedule showing for the last 5 years the income tax refunds, plus interest - net of taxes, received from the Federal government due to prior years' claims."

RESPONSE:

See Met-Ed Exhibit RAD-34 Attachment A.

Metropolitan Edision Company
Income Tax Refunds Prior Year Claims

( ) represents refunds

		Tax Refunds	Interest Rec	0.414935 Tax On Interest	Net Interest
Received 2009					
Claim for Refund					
	2001	(1,043,681.00)	(315,072.98)	130,734.81	(184,338.17)
Received 2010					
Interest Netting Claim					
	2001		(9,124.65)	3,786.14	(5,338.51)
NOL Carryback Claim	2009	(57,805,978.00)			
Received 2011					
Audit Settlement					
	2001	(484,798.00)	(155,231.00)	64,410.77	(90,820.23)
	2003	(3,223,577.00)	(810,659.00)	336,370.79	(474,288.21)
	2004	(1,281,749.00)	(724,754.00)	300,725.80	(424,028.20)
	2007	(1,628,952.00)	(97,283.00)	40,366.12	(56,916.88)
Received 2012					
NOL Carryback Claim	2011	(3,485,470.00)			
Received 2013					
None					
Total		(68,954,205.00)	(2,112,124.63)	876,394.43	(1,235,730.20)

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-18:

"Furnish a breakdown of major items comprising prepaid and deferred income tax charges and other deferred income tax credits, reserves and associated reversals on liberalized depreciation."

RESPONSE:

See Met-Ed Exhibit RAD-35 Attachment A.

Metropolitan Edison Company
Accumulated Deferred Taxes
($000)

Line No.		Balance at 04/30/16 (1)	(2)	Balance at 03/31/15 (3)	(4)	Balance at 03/31/14 (5)	(6)	Balance at 12/31/13 (7)	(8)
	Account 190-Accumulated Deferred Income Taxes								
1	Above Market NUG Liability	10,870		10,870		10,870		10,870	
2	Amortization Premium/Discount on Debt	807		397		79		-	
3	Asset Retirement Obligation - TMI2 Rad	96,011		95,989		95,963		95,957	
4	Asset Retirement Obligation -TMI2 Non Rad	1,257		1,257		1,257		1,257	
5	Bad Debts	2,922		2,922		2,922		2,922	
6	Charitable Contribution Limitation	217		217		217		217	
7	Company Debt - Gain on Reacquisition	405		470		530		547	
8	Consumer Education	320		320		320		320	
9	Customer Advances for Construction Operating	26		26		26		26	
10	Customer Deposits - Electric Service	5		5		5		5	
11	Decom TMI2 Non - Qualified Trust Tax Exempt Interest	53,819		53,819		53,819		53,819	
12	Decommissioning TMI2	36,567		36,567		36,567		36,567	
13	Decommissioning Unrealized Gain/Loss	2,477		2,477		2,477		2,477	
14	Deferred Compensation	383		383		383		383	
15	Default Serv Support-Unbilled Def	(298)		(296)		238		345	
16	DOE Spent Nuclear Fuel Disposal Interest - TMI	13,467		13,467		13,467		13,467	
17	Energy Efficiency Conservation Phase 2	1,706		1,706		1,706		1,706	
18	Energy Efficiency Deferral - EEC-C	4,605		4,108		3,617		3,532	
19	Energy Efficiency Unbilled Deferral	107		107		107		107	
20	Environmental Asset - Ash Sites	23		23		23		23	
21	FAS 112 - Medical Benefit Accrual	449		449		449		449	
22	FAS 123 R - APIC	402		402		402		402	
23	FAS 123R - Performance Shares	8		8		8		8	
24	FAS 123R - Restricted Stock	282		282		282		282	
25	FAS 123R - Restricted Stock Units	733		733		733		733	
26	FAS 123R - Stock Options	19		19		19		19	
27	FAS 133 - Hedging Transactions OCI	-		-		-		21	
28	FAS 158 Pension	282		282		282		296	
29	Federal NOL	7,685		8,538		23,355		23,355	
30	FICA on Vacation Accrual	140		140		140		140	
31	Investment Tax Credit	3,297		3,577		3,835		3,974	
32	Lease Expense Merrill Creek	11,560		11,560		11,560		11,560	
33	Merrill Creek Lease Improvement	6		6		6		6	
34	NUG Unbilled Deferral	203		203		203		203	
35	OCI - EDCP	134		134		134		139	
36	OCI - GPU SERP	1		1		1		1	
37	PA CNI NOL	3,379		5,329		7,331		7,331	
38	Pension EDCP-SERP Payments	41		41		41		41	
39	Pensions & Benefits in Excess of Max	127		127		127		127	
40	Pensions Expense	170,375		171,834		173,394		173,809	
41	Price to Compare Unbilled Deferral	9,286		9,286		9,286		9,286	
42	Reserve for Obsolescence	456		456		456		456	
43	Self Insurance - General Liability	199		199		199		199	
44	Self Insurance Reserve Workmans Compensaton	208		208		208		208	
45	Severance Wages	3		3		3		3	
46	Smart Meter Deferral/AMI	65		65		65		65	
47	Smart Meter Unbilled Deferral	125		125		125		125	
48	Solar Photovoltaic Req-Unbilled Def	52		52		52		52	
49	Solar Photovoltaic Req Charge Rider	847		665		356		288	
50	Storm Adjustment	520		520		520		520	
51	Tax Audit Reserves - General Taxes	938		938		938		938	
52	TMI-2 Monitored Storage- Disallowed Costs	5,507		5,507		5,507		5,507	
53	Universal Service Fund	7,091		4,892		3,682		3,430	
54	USCR Unbilled Deferral	803		803		803		803	
55	Vacation Pay Accrual	1,657		1,657		1,657		1,657	
56	FIN47 ARO Asbestos Remediation	397		397		397		397	
	Total Account 190		452,973		454,272		471,149		471,377
	Account 281-283 Accum. Deferred Income Taxes								
57	Liberalized Depreciation	(590,527)		(569,234)		(556,746)		(552,214)	
58	2013 PTC Admin	(326)		(326)		(326)		(326)	
59	Accounts Receivable - Deferred Revenue	(1,163)		(1,163)		(1,163)		(1,163)	
60	Company Debt - Loss on Reacquisition	(1,094)		(1,205)		(1,431)		(1,646)	
61	Decommissioning TMI2 Qual Principal	(26,803)		(26,803)		(26,803)		(26,803)	
62	Decommissioning TMI2 Qualified Investment	(106,355)		(106,355)		(106,355)		(106,355)	
63	Decommissioning TMI2 Unrealized Gain/Loss	(2,544)		(2,544)		(2,544)		(2,544)	
64	Decommissioning Trust - Pour Over Deduction	(74,752)		(74,752)		(74,752)		(74,752)	
65	Energy Efficiency Phase 2 Unbilled Deferral	(711)		(711)		(711)		(711)	

Metropolitan Edison Company
Accumulated Deferred Taxes
($000)

Line No.		Balance at 04/30/16 (1) (2)	Balance at 03/31/15 (3) (4)	Balance at 03/31/14 (5) (6)	Balance at 12/31/13 (7) (8)
66	Energy Insurance Services Cell 6	(53)	(53)	(53)	(53)
67	FAS 109 Gross Up	(55,465)	(55,308)	(55,304)	(55,049)
68	FAS 115 - Investment in Securities	(34)	(34)	(34)	(34)
69	FAS 123R - Restricted Stock Deduction	(97)	(97)	(97)	(97)
70	FAS 123R - Restricted Stock Unit Deduction	(403)	(403)	(403)	(403)
71	FAS 123R - Stock Options Exercised Deduction	(452)	(452)	(452)	(452)
72	FAS 158 OPEB	(4,667)	(7,603)	(12,851)	(14,308)
73	FE Service Non Property Timing Allocation	(5,576)	(5,576)	(6,016)	(6,163)
74	FE Service RSU 162(m) Val. Allow Allocation	(332)	(332)	(332)	(332)
75	FE Service Tax Interest Allocation	(5)	(5)	(5)	(5)
76	Incentive Compensation	(6)	(6)	(6)	(6)
77	Incremental PJM Deferral & Interest	(21,324)	(21,324)	(21,324)	(21,324)
78	Interest on Universal Services	648	222	(61)	(117)
79	NUG Derivative	(11,582)	(11,582)	(11,582)	(11,582)
80	OPEB Adj - Health Reform Act	(1,916)	(1,916)	(1,916)	(1,916)
81	Other Post Employ Benefits - Deferred	(2)	(2)	(2)	(2)
82	Other Post Employment Benefits O&M%	(20,645)	(19,440)	(16,426)	(15,560)
83	PA Corporate Net Income	(359)	(359)	(359)	(359)
84	Pensions Contribution	(109,962)	(109,962)	(109,962)	(109,962)
85	Price to Compare Rider	1,088	(2,259)	(2,643)	(1,550)
86	Reverse Capital Gain	(12)	(12)	(12)	(12)
87	Regulatory Assets - Other	(494)	(494)	(494)	-
88	State Income Tax - Fed Deferred Only	(6,799)	(6,799)	(6,799)	(6,799)
89	State Income Tax - RAR - Federal	(233)	(233)	(233)	(233)
90	Storm Damage	1,666	(8,600)	(19,551)	(21,935)
91	Tax Basis Step-Up	(38)	(32)	(30)	(30)
92	Vegetation Management - Transmission	(437)	(437)	(437)	(437)
93	Carrying Charge on Plant Held for Future Use	(344)	(344)	(344)	(344)
	Total Account 281-283	(1,042,110)	(1,036,535)	(1,038,559)	(1,035,578)
	Total Deferred Taxes	(589,137)	(582,263)	(567,410)	(564,201)

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-19:

> "Explain how the Federal corporate graduated tax rates have been reflected for rate case purposes. If the Pennsylvania jurisdictional utility is part of a multi-corporate system, explain how the tax savings are allocated to each member of the system."

RESPONSE:

Met-Ed is not entitled to a Federal graduated tax rate. Met-Ed files as a member of a Consolidated group and its taxable income exceeds where graduated rates apply. Therefore, the Company uses a flat 35% Federal income tax rate in this filing.

FirstEnergy allocates its current federal consolidated income tax liability, pursuant to an agreement approved by the Securities and Exchange Commission, in accordance with the Energy Policy Act of 2005.

Members of the FirstEnergy consolidated group follow the allocation rules under the IRS Regulations under Code Section 1552. The consolidated group is treated as one taxpayer for federal income tax. Each member is required to compute its separate company taxable income. The members with positive taxable income (Paying Members) pay the consolidate tax liability based on an allocation of its separate company income. The aggregate of all amounts paid by Members of the consolidated, as a result of the excess of each Members' Separate Return Tax liability, (as determined under Section 1.1552-1(a)(2)(ii) of the IRS Regulations) over the amount allocated to such Member as its share of the Consolidated Tax Liability under Code Section 1552 (i.e., the Tax Benefit Amount) is paid by FirstEnergy to the other Members (the "Loss Members") which had tax deductions, losses and credits to which such payments by the Paying Members are attributable. The apportionment of such payments among Loss Members is allocated among the group Members pursuant to IRS Regulations Section 1.1502-21(b).

However, the Tax Benefit Amount allocated to FirstEnergy and paid to FirstEnergy as a result of its being a Loss Member is limited to its Tax Benefit Amount determined by multiplying it total loss benefit amount by a fraction, the numerator of which is FirstEnergy's interest deduction attributable to Acquisition Indebtedness, and the denominator of which is the sum of all of FirstEnergy's deductions. The portion of FirstEnergy's Tax Benefit Amount which cannot be allocated and paid to FirstEnergy due to the operation of this limitation is reallocated to Paying Members of the Consolidated Group other than FirstEnergy in accordance with the method described in Sections 1.1502-33(d)(3) and 1.1552-1(a)(2) of the IRS Regulations.

The general effect of the method is to first allocate the consolidated tax liability among the Members of the Consolidated Group on the basis of the percentage of the total consolidated tax which the tax of such Member, if computed on a separate return basis would bear to the total amount of the taxes for all Members of the group so computed. Then the method allocates an additional amount (the "Tax Benefit Amount") to each Member up to, but not greater than, the excess, if any, of its Separate Return Tax liability, over the amount allocated to such Member in the previous sentence. The total of the Tax Benefit Amounts allocated to Members results in payments to the Members who had items of deduction, loss or credits to which such Tax Benefit Amount is attributable.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-20:

"Explain the treatment given to costs of removal in the income tax calculation and the basis for such treatment."

RESPONSE:

On property acquired from 1971 to 1980, the company utilizes the A.D.R. Tax Depreciation Method.

Under those regulations, when an asset is retired, the cost of dismantling, demolishing, or removing is deductible as a current year's expense.

In June, 1977, Metropolitan Edison Company filed with the Internal Revenue Service an application for a change in accounting for cost of removal on pre-1971 property to conform with treatment for book and regulatory purposes. The Internal Revenue Service's acceptance of this application was dated October 19, 1977.

On property acquired in 1981 and subsequent thereto, the company (in accordance with ACRS and MACRS regulations) elected to use Cost of Removal in the calculation of gain or loss on retirements of 1981 and subsequent property.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-21:

"Show income tax loss/gain carryovers from previous years. Show loss/gain carryovers by years of origin and amounts remaining by years at the beginning of the test year."

RESPONSE:

See Met-Ed Exhibit RAD-38 Attachment A for the Net Operating Loss ("NOL") Carryforward schedule.

Metropolitan Edison Company
Net Operating Loss Carryforwards - Federal & State
Cumulative Balance at 12-31-14

	2011	2012	2013	2014	Total
Federal NOL	$ 42,333,963	$ 23,021,568	$ -	$ -	$ 65,355,531
2014 Utilization	(23,272,040)				(23,272,040)
Balance	$ 19,061,923	$ 23,021,568	$ -	$ -	$ 42,083,491
					-
PA NOL	$ 112,898,985	$ -	$ -	$ -	$ 112,898,985
2012 Utilization	(3,000,000)	-	-	-	(3,000,000)
2013 Utilization	(30,055,692)	-	-	-	(30,055,692)
2014 Utilization	(27,713,701)				(27,713,701)
Balance	$ 52,129,592	$ -	$ -	$ -	$ 52,129,592

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-22:

"State whether the company eliminates tax savings by the payment of actual interest on construction work in progress not in rate base claim. If response is affirmative:

(a) Set forth amount of construction claimed in this tax savings reduction, and explain the basis for this amount
(b) Explain the manner in which the debt portion of this construction is determined for purposes of the deferral calculations.
(c) State the interest rate used to calculate interest on this construction debt portion, and the manner in which it is derived.
(d) Provide details of calculation to determine tax savings reduction, and state whether State taxes are increased to reflect the construction interest elimination."

RESPONSE:

One of the revisions made to the Internal Revenue Code (IRC) by the Tax Reform Act of 1996 was the elimination of the current deduction for construction period interest. The IRC now requires construction period interest to be capitalized for tax purposes using an avoided cost methodology. This methodology results in a similar required capitalized interest amount for tax purposes than the debt component of AFUDC. Therefore, there are no current tax savings to eliminate.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-23:

"Under section 1552 of the Internal Revenue Code (26 U.S.C.A. § 1552) and 26 CFR 1.1552-1 (1983), if applicable, a parent company, in filing a consolidated income tax return for the group, must choose one of four options by which it must allocate total income tax liability of the group to the participating members to determine each member's tax liability to the Federal government (if this interrogatory is not applicable, so state):

(a) State what option has been chosen by the group.
(b) Provide, in summary form, the amount of tax liability that has been allocated to each of the participating members in the consolidated income tax return for the test year and the most recent 3 years for which data is available.
(c) Provide a schedule, in summary form, of contributions, which were determined on the basis of separate tax return calculations, made by each of the participating members to the tax liability indicated in the consolidated group tax return. Provide total amounts of actual payments to the tax depository for the tax year, as computed on the basis of separate returns of members.
(d) Provide the most recent annual income tax return for the group.
(e) Provide details of the amount of the net operating losses of any member allocated to the income tax returns of each of the members of the consolidated group for the test year and the 3 most recent years for which data is available, together with a summary of the actual tax payments for those years.
(f) Provide details of the amount of net negative income taxes, after all tax credits are accounted for, of any member allocated to the income tax return of each of the members of the consolidated group for the test year and the 3 most recent years for which data is available, together with a summary of the actual tax payments for those years."

RESPONSE:

(a) The option used is Reg. §1.1552-1(a)(2) – the tax liability of the group is allocated based on the percentage of total tax computed on a separate basis for each member over the total amount of tax for all members of the group so computed.

(b) See Met-Ed Exhibit RAD-40, Attachment A[1], page 1, for the amount of the tax liability that has been allocated to each of the participating members in the Consolidated Federal income tax return for the most recent three years.

(c) See Met-Ed Exhibit RAD-40, Attachment A, pages 7 – 39, for the payments and refunds made for the most recent filed returns for years 2010, 2011, and 2012 as computed on the basis of separate returns of members.

(d) See Met-Ed Exhibit RAD-40, Attachment A, pages 2 – 6, for a copy of the U.S. Corporation Income Tax Return (Form 1120) as filed by FirstEnergy Corp. and Subsidiaries for the year 2012.

(e) See Met-Ed Exhibit RAD-40, Attachment A, pages 2 - 39.

(f) See Met-Ed Exhibit RAD-40, Attachment A, pages 2 - 39.

[1] Attachment A to Met-Ed Exhibit RAD-40 is **Highly Confidential** and is being provided to the Commission in hard copy only.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-24:

"Provide detailed computations by vintage year showing State and Federal deferred income taxes resulting from the use of accelerated tax depreciation associated with post-1969 public utility property, ADR rates, and accelerated tax depreciation associated with post-1980 public utility property under the Accelerated Cost Recovery System (ACRS).

(a) Reconcile and explain any differences in the base used to calculate State and Federal deferred income taxes.

(b) State whether tax depreciation is based on all rate base items claimed as of the end of the test year, and whether it is the annual tax depreciation at the end of the test year.

(c) Reconcile differences between the deferred tax balance, as shown as a reduction to rate base, and the deferred tax balance as shown on the balance sheet."

RESPONSE:

(a) See Met-Ed Exhibit RAD-41 Attachment A. No basis difference, however, there is a timing difference due to PA disallowance in year one of the 50% Federal Bonus Depreciation.

(b) See Met-Ed Exhibit RAD-41 Attachment A. Tax depreciation for the future test year is based on all electric plant in service claimed as of 4/30/16 and the annual tax depreciation is based on the same plant.

(c) See Met-Ed Exhibit RAD-41 Attachment B.

METROPOLITAN EDISON COMPANY
Summary of Deferred Income Taxes
Based upon Electric Plant in Service April, 2013 - March, 2014

		Deferral of Taxes			Pro Forma Under Present Rates	
Vintage Year		State	Federal	Total	Normalizing Adjustments	Total
Provision:	1970	-	-	-		-
	1971	-	-	-		-
	1972	-	994	994		994
	1973	-	1,216	1,216		1,216
	1974	-	3	3		3
	1975	-	324	324		324
	1976	-	323	323		323
	1977	-	151	151		151
	1978	-	2,989	2,989		2,989
	1979	-	608	608		608
	1980	-	524	524		524
	1981	-	1,653	1,653		1,653
	1982	-	3,387	3,387		3,387
	1983	-	5,118	5,118		5,118
	1984	-	6,706	6,706		6,706
	1985	-	3,113	3,113		3,113
	1986	-	7,071	7,071		7,071
	1987	-	5,857	5,857		5,857
	1988	-	19,107	19,107		19,107
	1989	-	11,953	11,953		11,953
	1990	-	11,401	11,401		11,401
	1991	-	70,803	70,803		70,803
	1992	-	8,259	8,259		8,259
	1993	-	33,436	33,436		33,436
	1994	-	348,509	348,509		348,509
	1995	-	556,863	556,863		556,863
	1996	-	334,362	334,362		334,362
	1997	-	455,081	455,081		455,081
	1998	-	627,400	627,400		627,400
	1999	-	356,328	356,328		356,328
	2000	-	430,603	430,603		430,603
	2001	-	446,242	446,242		446,242
	2001 30%	-	16,759	16,759		16,759
	2002	-	70,482	70,482		70,482
	2002 30%	-	128,483	128,483		128,483
	2003	-	3,305	3,305		3,305
	2003 30%	-	102,719	102,719		102,719
	2003 50%	-	25,796	25,796		25,796
	2004	-	(6,700)	(6,700)		(6,700)
	2004 30%	-	134,720	134,720		134,720
	2004 50%	-	27,184	27,184		27,184
	2005	-	363,392	363,392		363,392
	2006	-	795,398	795,398		795,398
	2007	-	810,669	810,669		810,669
	2008	-	297,955	297,955		297,955
	2008 50%	-	187,419	187,419		187,419
	2009	-	364,375	364,375		364,375
	2009 50%	-	595,660	595,660		595,660
	2010	-	(14,489)	(14,489)		(14,489)
	2010 100%	-	-	-		-
	2010 50%	-	261,521	261,521		261,521
	2011	-	235,878	235,878		235,878
	2011 100%	-	3,305	3,305		3,305
	2011 50%	-	134,883	134,883		134,883
	2012	-	161,593	161,593		161,593
	2012 50%	-	1,569,236	1,569,236		1,569,236
	2013	-	229,209	229,209		229,209
	2013 50%	-	11,587,892	11,587,892		11,587,892
	2014	-	2,141,004	2,141,004		2,141,004
Total Provision		-	23,978,032	23,978,032	-	23,978,032

METROPOLITAN EDISON COMPANY
Summary of Deferred Income Taxes
Based upon Electric Plant in Service April, 2013 - March, 2014

Vintage Year	Deferral of Taxes State	Deferral of Taxes Federal	Total	Pro Forma Under Present Rates: Normalizing Adjustments	Pro Forma Under Present Rates: Total
Reversal					
1970	-	(4,636)	(4,636)		(4,636)
1971	-	(15,968)	(15,968)		(15,968)
1972	-	(13,356)	(13,356)		(13,356)
1973	-	(15,151)	(15,151)		(15,151)
1974	-	(16,365)	(16,365)		(16,365)
1975	-	(7,345)	(7,345)		(7,345)
1976	-	(71,384)	(71,384)		(71,384)
1977	-	(14,748)	(14,748)		(14,748)
1978	-	16,307	16,307		16,307
1979	-	22,161	22,161		22,161
1980	-	44,228	44,228		44,228
1981	-	(94,410)	(94,410)		(94,410)
1982	-	(100,051)	(100,051)		(100,051)
1983	-	(170,282)	(170,282)		(170,282)
1984	-	(162,105)	(162,105)		(162,105)
1985	-	(247,619)	(247,619)		(247,619)
1986	-	(275,896)	(275,896)		(275,896)
1987	-	(275,958)	(275,958)		(275,958)
1988	-	(292,748)	(292,748)		(292,748)
1989	-	(331,844)	(331,844)		(331,844)
1990	-	(347,057)	(347,057)		(347,057)
1991	-	(371,036)	(371,036)		(371,036)
1992	-	(372,071)	(372,071)		(372,071)
1993	-	(277,084)	(277,084)		(277,084)
1994	-	(328,666)	(328,666)		(328,666)
1995	-	(445,490)	(445,490)		(445,490)
1996	-	(282,369)	(282,369)		(282,369)
1997	-	(360,251)	(360,251)		(360,251)
1998	-	(439,378)	(439,378)		(439,378)
1999	-	(270,252)	(270,252)		(270,252)
2000	-	(333,594)	(333,594)		(333,594)
2001	-	(324,223)	(324,223)		(324,223)
2001 30%	-	(447)	(447)		(447)
2002	-	(171,193)	(171,193)		(171,193)
2002 30%	-	42,613	42,613		42,613
2003	-	(169,789)	(169,789)		(169,789)
2003 30%	-	35,419	35,419		35,419
2003 50%	-	10,166	10,166		10,166
2004	-	(271,769)	(271,769)		(271,769)
2004 30%	-	(5,753)	(5,753)		(5,753)
2004 50%	-	103,448	103,448		103,448
2005	-	(60,873)	(60,873)		(60,873)
2006	-	(529,054)	(529,054)		(529,054)
2007	-	(756,360)	(756,360)		(756,360)
2008	-	(346,644)	(346,644)		(346,644)
2008 50%	-	(55,327)	(55,327)		(55,327)
2009	-	(434,693)	(434,693)		(434,693)
2009 50%	-	342,458	342,458		342,458
2010	-	45,779	45,779		45,779
2010 100%	-	(159,460)	(159,460)		(159,460)
2010 50%	-	122,703	122,703		122,703
2011	-	(1,018,618)	(1,018,618)		(1,018,618)
2011 100%	-	(691,714)	(691,714)		(691,714)
2011 50%	-	(11,896)	(11,896)		(11,896)
2012	-	(100,801)	(100,801)		(100,801)
2012 50%	-	(210,754)	(210,754)		(210,754)
2013	-	30,949	30,949		30,949
2013 50%	-	159,393	159,393		159,393
2014	-	(78,714)	(78,714)		(78,714)
Total Reversal	-	(10,359,574)	(10,359,574)	-	(10,359,574)
Net Provision	-	13,618,458	13,618,458	-	13,618,458

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service April, 2013 - March, 2014

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
Provision						
1970	-	0%	35%	-	-	-
1971	-	0%	35%	-	-	-
1972	2,839	0%	35%	-	994	994
1973	3,474	0%	35%	-	1,216	1,216
1974	8	0%	35%	-	3	3
1975	926	0%	35%	-	324	324
1976	923	0%	35%	-	323	323
1977	431	0%	35%	-	151	151
1978	8,541	0%	35%	-	2,989	2,989
1979	1,738	0%	35%	-	608	608
1980	1,496	0%	35%	-	524	524
1981	4,625	0%	35%	-	1,619	1,619
1982	9,678	0%	35%	-	3,387	3,387
1983	14,624	0%	35%	-	5,118	5,118
1984	19,160	0%	35%	-	6,706	6,706
1985	8,894	0%	35%	-	3,113	3,113
1986	20,202	0%	35%	-	7,071	7,071
1987	16,133	0%	35%	-	5,646	5,646
1988	43,848	0%	35%	-	15,347	15,347
1989	33,205	0%	35%	-	11,622	11,622
1990	30,922	0%	35%	-	10,823	10,823
1991	197,360	0%	35%	-	69,076	69,076
1992	21,255	0%	35%	-	7,439	7,439
1993	84,370	0%	35%	-	29,530	29,530
1994	978,940	0%	35%	-	342,629	342,629
1995	1,496,098	0%	35%	-	523,634	523,634
1996	869,054	0%	35%	-	304,169	304,169
1997	1,232,880	0%	35%	-	431,508	431,508
1998	1,606,989	0%	35%	-	562,446	562,446
1999	909,832	0%	35%	-	318,441	318,441
2000	1,155,874	0%	35%	-	404,556	404,556
2001	1,194,770	0%	35%	-	418,169	418,169
2001 30%	45,291	0%	35%	-	15,852	15,852
2002	193,212	0%	35%	-	67,624	67,624
2002 30%	339,677	0%	35%	-	118,887	118,887
2003	7,924	0%	35%	-	2,774	2,774
2003 30%	176,771	0%	35%	-	61,870	61,870
2003 50%	62,376	0%	35%	-	21,832	21,832
2004	(17,422)	0%	35%	-	(6,098)	(6,098)
2004 30%	357,363	0%	35%	-	125,077	125,077
2004 50%	63,635	0%	35%	-	22,272	22,272
2005	907,656	0%	35%	-	317,680	317,680
2006	2,085,732	0%	35%	-	730,006	730,006
2007	2,104,433	0%	35%	-	736,552	736,552
2008	806,863	0%	35%	-	282,402	282,402
2008 50%	455,068	0%	35%	-	159,274	159,274
2009	1,008,045	0%	35%	-	352,816	352,816
2009 50%	1,531,603	0%	35%	-	536,061	536,061
2010	(42,279)	0%	35%	-	(14,798)	(14,798)
2010 100%	-	0%	35%	-	-	-
2010 50%	644,394	0%	35%	-	225,538	225,538
2011	631,979	0%	35%	-	221,193	221,193
2011 100%	9,442	0%	35%	-	3,305	3,305
2011 50%	344,570	0%	35%	-	120,599	120,599
2012	378,734	0%	35%	-	132,557	132,557
2012 50%	3,816,949	0%	35%	-	1,335,932	1,335,932
2013	571,085	0%	35%	-	199,880	199,880
2013 50%	32,882,828	0%	35%	-	11,508,990	11,508,990
2014	6,117,155	0%	35%	-	2,141,004	2,141,004
	65,452,172			**-**	**22,908,260**	**22,908,260**
Provision Gains/Losses Page (6)				**-**	**$1,069,737**	**$1,069,737**
Provision - Non - TMI				**-**	**$23,977,997**	**$23,977,997**

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service April, 2013 - March, 2014

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
Reversal						
1970	(9,688)	0%	48%	-	(4,636)	(4,636)
1971	(33,295)	0%	48%	-	(15,968)	(15,968)
1972	(27,856)	0%	48%	-	(13,356)	(13,356)
1973	(31,606)	0%	48%	-	(15,151)	(15,151)
1974	(34,145)	0%	48%	-	(16,365)	(16,365)
1975	(15,333)	0%	48%	-	(7,345)	(7,345)
1976	(148,772)	0%	48%	-	(71,384)	(71,384)
1977	(30,802)	0%	48%	-	(14,748)	(14,748)
1978	(13,643)	0%	48%	-	(6,501)	(6,501)
1979	(8,624)	0%	46%	-	(3,947)	(3,947)
1980	(21,780)	0%	46%	-	(9,992)	(9,992)
1981	(228,628)	0%	42%	-	(95,638)	(95,638)
1982	(247,484)	0%	41%	-	(100,275)	(100,275)
1983	(429,729)	0%	40%	-	(171,095)	(171,095)
1984	(418,085)	0%	39%	-	(162,492)	(162,492)
1985	(651,290)	0%	38%	-	(248,428)	(248,428)
1986	(752,780)	0%	37%	-	(276,187)	(276,187)
1987	(798,131)	0%	35%	-	(278,125)	(278,125)
1988	(834,692)	0%	35%	-	(292,748)	(292,748)
1989	(955,653)	0%	35%	-	(331,843)	(331,843)
1990	(1,001,168)	0%	35%	-	(347,057)	(347,057)
1991	(1,064,866)	0%	35%	-	(371,036)	(371,036)
1992	(1,062,239)	0%	35%	-	(371,749)	(371,749)
1993	(791,668)	0%	35%	-	(277,084)	(277,084)
1994	(939,046)	0%	35%	-	(328,666)	(328,666)
1995	(1,272,828)	0%	35%	-	(445,490)	(445,490)
1996	(806,769)	0%	35%	-	(282,369)	(282,369)
1997	(1,029,288)	0%	35%	-	(360,251)	(360,251)
1998	(1,255,366)	0%	35%	-	(439,378)	(439,378)
1999	(772,148)	0%	35%	-	(270,252)	(270,252)
2000	(953,126)	0%	35%	-	(333,594)	(333,594)
2001	(926,352)	0%	35%	-	(324,223)	(324,223)
2001 30%	(1,277)	0%	35%	-	(447)	(447)
2002	(489,124)	0%	35%	-	(171,193)	(171,193)
2002 30%	121,750	0%	35%	-	42,613	42,613
2003	(485,111)	0%	35%	-	(169,789)	(169,789)
2003 30%	101,198	0%	35%	-	35,419	35,419
2003 50%	29,047	0%	35%	-	10,166	10,166
2004	(776,482)	0%	35%	-	(271,769)	(271,769)
2004 30%	(16,437)	0%	35%	-	(5,753)	(5,753)
2004 50%	295,566	0%	35%	-	103,448	103,448
2005	(173,923)	0%	35%	-	(60,873)	(60,873)
2006	(1,511,584)	0%	35%	-	(529,054)	(529,054)
2007	(2,161,030)	0%	35%	-	(756,360)	(756,360)
2008	(990,412)	0%	35%	-	(346,644)	(346,644)
2008 50%	(158,077)	0%	35%	-	(55,327)	(55,327)
2009	(1,241,979)	0%	35%	-	(434,693)	(434,693)
2009 50%	978,451	0%	35%	-	342,458	342,458
2010	130,796	0%	35%	-	45,779	45,779
2010 100%	(455,600)	0%	35%	-	(159,460)	(159,460)
2010 50%	350,579	0%	35%	-	122,703	122,703
2011	(2,910,337)	0%	35%	-	(1,018,618)	(1,018,618)
2011 100%	(1,976,325)	0%	35%	-	(691,714)	(691,714)
2011 50%	(33,989)	0%	35%	-	(11,896)	(11,896)
2012	(288,003)	0%	35%	-	(100,801)	(100,801)
2012 50%	(602,155)	0%	35%	-	(210,754)	(210,754)
2013	88,425	0%	35%	-	30,949	30,949
2013 50%	455,408	0%	35%	-	159,393	159,393
2014	(224,897)	0%	35%	-	(78,714)	(78,714)
Reversal Non-TMI	(29,512,402)			**-**	**(10,468,308)**	**(10,468,308)**
Total Net Provison - Non-TMI				**-**	**13,509,689**	**13,509,689**

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service April, 2013 - March, 2014
Deferred Income Taxes Related to Gains/Losses

Vintage Year	Per Power Tax Report 52 Basis of Property	Accumulated Tax Depreciation	(Gain)/Loss recognized	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
	1	2	3	4	5	6 = 3 x 4	7 =3 x 5	8 = 6+7
Provision - 4/13-3/14								
1987	317,244	316,641	602	0%	35%	-	211	211
1988	263,933	253,188	10,745	0%	35%	-	3,761	3,761
1989	357,749	356,803	946	0%	35%	-	331	331
1990	893,880	892,229	1,652	0%	35%	-	578	578
1991	398,725	393,792	4,933	0%	35%	-	1,726	1,726
1992	336,196	333,854	2,342	0%	35%	-	820	820
1993	449,618	438,456	11,162	0%	35%	-	3,907	3,907
1994	335,669	318,868	16,800	0%	35%	-	5,880	5,880
1995	1,060,613	965,673	94,940	0%	35%	-	33,229	33,229
1996	721,828	635,561	86,267	0%	35%	-	30,193	30,193
1997	413,505	346,155	67,350	0%	35%	-	23,573	23,573
1998	899,997	714,414	185,583	0%	35%	-	64,954	64,954
1999	420,800	312,553	108,247	0%	35%	-	37,887	37,887
2000	258,751	184,330	74,421	0%	35%	-	26,047	26,047
2001	233,836	153,629	80,207	0%	35%	-	28,072	28,072
2001 30%	7,609	5,017	2,592	0%	35%	-	907	907
2002	24,205	16,041	8,164	0%	35%	-	2,857	2,857
2002 30%	70,722	43,303	27,418	0%	35%	-	9,596	9,596
2003	3,240	1,722	1,518	0%	35%	-	531	531
2003 30%	269,391	152,678	116,712	0%	35%	-	40,849	40,849
2003 50%	26,390	15,064	11,326	0%	35%	-	3,964	3,964
2004	(831)	888	(1,719)	0%	35%	-	(602)	(602)
2004 30%	59,850	32,300	27,550	0%	35%	-	9,643	9,643
2004 50%	29,922	15,889	14,034	0%	35%	-	4,912	4,912
2005	249,780	119,173	130,607	0%	35%	-	45,712	45,712
2006	328,810	141,976	186,834	0%	35%	-	65,392	65,392
2007	351,003	139,239	211,764	0%	35%	-	74,117	74,117
2008	69,404	24,967	44,437	0%	35%	-	15,553	15,553
2008 50%	124,233	43,819	80,414	0%	35%	-	28,145	28,145
2009	81,761	48,734	33,027	0%	35%	-	11,559	11,559
2009 50%	243,575	73,291	170,284	0%	35%	-	59,599	59,599
2010	2,208	1,326	881	0%	35%	-	308	308
2010 100%	-	-	-	0%	35%	-	-	-
2010 50%	170,232	67,424	102,808	0%	35%	-	35,983	35,983
2011	51,287	9,330	41,957	0%	35%	-	14,685	14,685
2011 100%	-	-	-	0%	35%	-	-	-
2011 50%	93,202	52,392	40,810	0%	35%	-	14,283	14,283
2012	89,609	6,648	82,961	0%	35%	-	29,036	29,036
2012 50%	722,465	55,881	666,583	0%	35%	-	233,304	233,304
2013	85,276	1,479	83,797	0%	35%	-	29,329	29,329
2013 50%	229,163	3,729	225,434	0%	35%	-	78,902	78,902
Provision - Non-TMI (gains/losses)							1,069,737	1,069,737

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - TMI #2
Based upon Electric Plant in Service April, 2013 - March, 2014

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Deferral of Taxes State	Federal	Total
Provision				
1978	-	-	-	-
1979	-	-	-	-
1980	-	-	-	-
1981	99	-	35	35
1982	-	-	-	-
1983	-	-	-	-
1984	-	-	-	-
1985	-	-	-	-
1986	-	-	-	-
1987	-	-	-	-
1988	-	-	-	-
1989	-	-	-	-
1992	-	-	-	-
	99	-	35	35

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Deferral of Taxes State	Federal	Total
Reversal				
1978	47,517	-	22,808	22,808
1979	56,758	-	26,109	26,109
1980	117,870	-	54,220	54,220
1981	(3)	-	1,228	1,228
1982	-	-	224	224
1983	-	-	813	813
1984	-	-	387	387
1985	-	-	809	809
1986	-	-	291	291
1987	-	-	2,168	2,168
1988	-	-	(1)	(1)
1989	-	-	(1)	(1)
1992	-	-	(322)	(322)
	222,142	-	108,734	108,734

METROPOLITAN EDISON COMPANY
Summary of Deferred Income Taxes
Based upon Electric Plant in Service April, 2014 - April, 2015

		Deferral of Taxes			Pro Forma Under Present Rates	
	Vintage Year	State	Federal	Total	Normalizing Adjustments	Total
Provision:	1970	-	-	-		-
	1971	-	-	-		-
	1972	-	745	745		745
	1973	-	1,309	1,309		1,309
	1974	-	2	2		2
	1975	-	293	293		293
	1976	-	291	291		291
	1977	-	161	161		161
	1978	-	3,239	3,239		3,239
	1979	-	657	657		657
	1980	-	567	567		567
	1981	-	1,376	1,376		1,376
	1982	-	1,669	1,669		1,669
	1983	-	2,164	2,164		2,164
	1984	-	2,304	2,304		2,304
	1985	-	2,698	2,698		2,698
	1986	-	3,187	3,187		3,187
	1987	-	10,734	10,734		10,734
	1988	-	19,751	19,751		19,751
	1989	-	19,635	19,635		19,635
	1990	-	20,718	20,718		20,718
	1991	-	111,593	111,593		111,593
	1992	-	17,367	17,367		17,367
	1993	-	12,286	12,286		12,286
	1994	-	124,974	124,974		124,974
	1995	-	452,679	452,679		452,679
	1996	-	337,405	337,405		337,405
	1997	-	535,769	535,769		535,769
	1998	-	658,098	658,098		658,098
	1999	-	381,272	381,272		381,272
	2000	-	513,426	513,426		513,426
	2001	-	539,087	539,087		539,087
	2001 30%	-	24,269	24,269		24,269
	2002	-	87,032	87,032		87,032
	2002 30%	-	176,487	176,487		176,487
	2003	-	5,172	5,172		5,172
	2003 30%	-	97,205	97,205		97,205
	2003 50%	-	62,415	62,415		62,415
	2004	-	(9,913)	(9,913)		(9,913)
	2004 30%	-	198,213	198,213		198,213
	2004 50%	-	60,765	60,765		60,765
	2005	-	462,623	462,623		462,623
	2006	-	944,154	944,154		944,154
	2007	-	878,976	878,976		878,976
	2008	-	325,382	325,382		325,382
	2008 50%	-	264,184	264,184		264,184
	2009	-	358,251	358,251		358,251
	2009 50%	-	697,076	697,076		697,076
	2010	-	(35,423)	(35,423)		(35,423)
	2010 100%	-	-	-		-
	2010 50%	-	325,477	325,477		325,477
	2011	-	366,972	366,972		366,972
	2011 100%	-	-	-		-
	2011 50%	-	45,722	45,722		45,722
	2012	-	136,217	136,217		136,217
	2012 50%	-	1,134,495	1,134,495		1,134,495
	2013	-	384,597	384,597		384,597
	2013 50%	-	641,658	641,658		641,658
	2014	-	7,620,876	7,620,876		7,620,876
	2015	-	3,711,808	3,711,808		3,711,808
Total Provision		-	22,740,145	22,740,145	-	22,740,145

METROPOLITAN EDISON COMPANY
Summary of Deferred Income Taxes
Based upon Electric Plant in Service April, 2014 - April, 2015

Vintage Year	Deferral of Taxes State	Deferral of Taxes Federal	Total	Pro Forma Under Present Rates: Normalizing Adjustments	Pro Forma Under Present Rates: Total
Reversal					
1970	-	(4,853)	(4,853)		(4,853)
1971	-	(16,071)	(16,071)		(16,071)
1972	-	(13,689)	(13,689)		(13,689)
1973	-	(15,539)	(15,539)		(15,539)
1974	-	(16,915)	(16,915)		(16,915)
1975	-	(7,464)	(7,464)		(7,464)
1976	-	(71,662)	(71,662)		(71,662)
1977	-	(14,979)	(14,979)		(14,979)
1978	-	16,252	16,252		16,252
1979	-	22,160	22,160		22,160
1980	-	44,274	44,274		44,274
1981	-	(82,271)	(82,271)		(82,271)
1982	-	(89,611)	(89,611)		(89,611)
1983	-	(147,188)	(147,188)		(147,188)
1984	-	(145,200)	(145,200)		(145,200)
1985	-	(215,727)	(215,727)		(215,727)
1986	-	(241,138)	(241,138)		(241,138)
1987	-	(245,412)	(245,412)		(245,412)
1988	-	(253,339)	(253,339)		(253,339)
1989	-	(292,662)	(292,662)		(292,662)
1990	-	(335,497)	(335,497)		(335,497)
1991	-	(327,227)	(327,227)		(327,227)
1992	-	(322,355)	(322,355)		(322,355)
1993	-	(317,478)	(317,478)		(317,478)
1994	-	(256,920)	(256,920)		(256,920)
1995	-	(405,394)	(405,394)		(405,394)
1996	-	(300,725)	(300,725)		(300,725)
1997	-	(383,294)	(383,294)		(383,294)
1998	-	(463,536)	(463,536)		(463,536)
1999	-	(290,122)	(290,122)		(290,122)
2000	-	(356,402)	(356,402)		(356,402)
2001	-	(345,526)	(345,526)		(345,526)
2001 30%	-	(451)	(451)		(451)
2002	-	(181,516)	(181,516)		(181,516)
2002 30%	-	47,482	47,482		47,482
2003	-	(181,535)	(181,535)		(181,535)
2003 30%	-	30,673	30,673		30,673
2003 50%	-	11,192	11,192		11,192
2004	-	(292,960)	(292,960)		(292,960)
2004 30%	-	(3,809)	(3,809)		(3,809)
2004 50%	-	109,301	109,301		109,301
2005	-	(20,084)	(20,084)		(20,084)
2006	-	(549,874)	(549,874)		(549,874)
2007	-	(730,277)	(730,277)		(730,277)
2008	-	(343,389)	(343,389)		(343,389)
2008 50%	-	(56,642)	(56,642)		(56,642)
2009	-	(430,221)	(430,221)		(430,221)
2009 50%	-	347,392	347,392		347,392
2010	-	53,969	53,969		53,969
2010 100%	-	(135,766)	(135,766)		(135,766)
2010 50%	-	59,335	59,335		59,335
2011	-	(1,023,862)	(1,023,862)		(1,023,862)
2011 100%	-	(600,376)	(600,376)		(600,376)
2011 50%	-	(48,495)	(48,495)		(48,495)
2012	-	(109,046)	(109,046)		(109,046)
2012 50%	-	(195,393)	(195,393)		(195,393)
2013	-	45,787	45,787		45,787
2013 50%	-	233,831	233,831		233,831
2014	-	(424,122)	(424,122)		(424,122)
2015	-	(52,315)	(52,315)		(52,315)
Total Reversal	-	(10,336,688)	(10,336,688)	-	(10,336,688)
Net Provision	-	12,403,457	12,403,457	-	12,403,457

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service April, 2014 - April, 2015

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
Provision						
1970	-	0%	35%	-	-	-
1971	-	0%	35%	-	-	-
1972	2,128	0%	35%	-	745	745
1973	3,741	0%	35%	-	1,309	1,309
1974	5	0%	35%	-	2	2
1975	836	0%	35%	-	293	293
1976	833	0%	35%	-	291	291
1977	460	0%	35%	-	161	161
1978	9,253	0%	35%	-	3,239	3,239
1979	1,878	0%	35%	-	657	657
1980	1,620	0%	35%	-	567	567
1981	3,822	0%	35%	-	1,338	1,338
1982	4,769	0%	35%	-	1,669	1,669
1983	6,183	0%	35%	-	2,164	2,164
1984	6,582	0%	35%	-	2,304	2,304
1985	7,710	0%	35%	-	2,698	2,698
1986	9,106	0%	35%	-	3,187	3,187
1987	28,225	0%	35%	-	9,879	9,879
1988	52,237	0%	35%	-	18,283	18,283
1989	52,272	0%	35%	-	18,295	18,295
1990	52,421	0%	35%	-	18,347	18,347
1991	298,884	0%	35%	-	104,609	104,609
1992	39,917	0%	35%	-	13,971	13,971
1993	5,598	0%	35%	-	1,959	1,959
1994	332,536	0%	35%	-	116,388	116,388
1995	1,271,677	0%	35%	-	445,087	445,087
1996	941,117	0%	35%	-	329,391	329,391
1997	1,495,439	0%	35%	-	523,404	523,404
1998	1,834,332	0%	35%	-	642,016	642,016
1999	1,058,754	0%	35%	-	370,564	370,564
2000	1,420,461	0%	35%	-	497,161	497,161
2001	1,481,935	0%	35%	-	518,677	518,677
2001 30%	65,984	0%	35%	-	23,095	23,095
2002	236,947	0%	35%	-	82,931	82,931
2002 30%	474,454	0%	35%	-	166,059	166,059
2003	8,953	0%	35%	-	3,133	3,133
2003 30%	259,746	0%	35%	-	90,911	90,911
2003 50%	162,008	0%	35%	-	56,703	56,703
2004	(20,853)	0%	35%	-	(7,299)	(7,299)
2004 30%	528,214	0%	35%	-	184,875	184,875
2004 50%	149,566	0%	35%	-	52,348	52,348
2005	1,176,219	0%	35%	-	411,677	411,677
2006	2,526,278	0%	35%	-	884,197	884,197
2007	2,338,924	0%	35%	-	818,623	818,623
2008	864,897	0%	35%	-	302,714	302,714
2008 50%	665,761	0%	35%	-	233,017	233,017
2009	962,706	0%	35%	-	336,947	336,947
2009 50%	1,786,413	0%	35%	-	625,245	625,245
2010	(102,643)	0%	35%	-	(35,925)	(35,925)
2010 100%	-	0%	35%	-	-	-
2010 50%	824,151	0%	35%	-	288,453	288,453
2011	1,004,758	0%	35%	-	351,665	351,665
2011 100%	-	0%	35%	-	-	-
2011 50%	119,173	0%	35%	-	41,710	41,710
2012	364,290	0%	35%	-	127,501	127,501
2012 50%	3,049,214	0%	35%	-	1,067,225	1,067,225
2013	1,028,742	0%	35%	-	360,060	360,060
2013 50%	1,684,396	0%	35%	-	589,539	589,539
2014	21,688,106	0%	35%	-	7,590,837	7,590,837
2015	10,605,166	0%	35%	-	3,711,808	3,711,808
	62,876,298			-	22,006,704	22,006,704
Provision Gains/Losses Page (12)				**-**	**733,403**	**733,403**
Provision - Non - TMI				**-**	**22,740,107**	**22,740,107**

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service April, 2014 - April, 2015

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
Reversal						
1970	(10,147)	0%	48%	-	(4,853)	(4,853)
1971	(33,520)	0%	48%	-	(16,071)	(16,071)
1972	(28,652)	0%	48%	-	(13,689)	(13,689)
1973	(32,424)	0%	48%	-	(15,539)	(15,539)
1974	(35,302)	0%	48%	-	(16,915)	(16,915)
1975	(15,587)	0%	48%	-	(7,464)	(7,464)
1976	(149,363)	0%	48%	-	(71,662)	(71,662)
1977	(31,303)	0%	48%	-	(14,979)	(14,979)
1978	(13,986)	0%	48%	-	(6,653)	(6,653)
1979	(8,882)	0%	46%	-	(4,060)	(4,060)
1980	(22,202)	0%	46%	-	(10,177)	(10,177)
1981	(198,725)	0%	42%	-	(83,504)	(83,504)
1982	(221,510)	0%	41%	-	(89,837)	(89,837)
1983	(370,832)	0%	40%	-	(148,004)	(148,004)
1984	(374,089)	0%	39%	-	(145,589)	(145,589)
1985	(565,347)	0%	38%	-	(216,540)	(216,540)
1986	(655,399)	0%	37%	-	(241,431)	(241,431)
1987	(708,199)	0%	35%	-	(247,589)	(247,589)
1988	(727,302)	0%	35%	-	(253,338)	(253,338)
1989	(839,669)	0%	35%	-	(292,662)	(292,662)
1990	(967,688)	0%	35%	-	(335,497)	(335,497)
1991	(939,179)	0%	35%	-	(327,227)	(327,227)
1992	(920,041)	0%	35%	-	(322,032)	(322,032)
1993	(907,080)	0%	35%	-	(317,478)	(317,478)
1994	(734,056)	0%	35%	-	(256,920)	(256,920)
1995	(1,158,268)	0%	35%	-	(405,394)	(405,394)
1996	(859,214)	0%	35%	-	(300,725)	(300,725)
1997	(1,095,126)	0%	35%	-	(383,294)	(383,294)
1998	(1,324,389)	0%	35%	-	(463,536)	(463,536)
1999	(828,921)	0%	35%	-	(290,122)	(290,122)
2000	(1,018,291)	0%	35%	-	(356,402)	(356,402)
2001	(987,216)	0%	35%	-	(345,526)	(345,526)
2001 30%	(1,287)	0%	35%	-	(451)	(451)
2002	(518,617)	0%	35%	-	(181,516)	(181,516)
2002 30%	135,662	0%	35%	-	47,482	47,482
2003	(518,673)	0%	35%	-	(181,535)	(181,535)
2003 30%	87,636	0%	35%	-	30,673	30,673
2003 50%	31,977	0%	35%	-	11,192	11,192
2004	(837,030)	0%	35%	-	(292,960)	(292,960)
2004 30%	(10,883)	0%	35%	-	(3,809)	(3,809)
2004 50%	312,288	0%	35%	-	109,301	109,301
2005	(57,383)	0%	35%	-	(20,084)	(20,084)
2006	(1,571,069)	0%	35%	-	(549,874)	(549,874)
2007	(2,086,507)	0%	35%	-	(730,277)	(730,277)
2008	(981,111)	0%	35%	-	(343,389)	(343,389)
2008 50%	(161,835)	0%	35%	-	(56,642)	(56,642)
2009	(1,229,202)	0%	35%	-	(430,221)	(430,221)
2009 50%	992,547	0%	35%	-	347,392	347,392
2010	154,197	0%	35%	-	53,969	53,969
2010 100%	(387,902)	0%	35%	-	(135,766)	(135,766)
2010 50%	169,528	0%	35%	-	59,335	59,335
2011	(2,925,319)	0%	35%	-	(1,023,862)	(1,023,862)
2011 100%	(1,715,360)	0%	35%	-	(600,376)	(600,376)
2011 50%	(138,556)	0%	35%	-	(48,495)	(48,495)
2012	(311,560)	0%	35%	-	(109,046)	(109,046)
2012 50%	(558,267)	0%	35%	-	(195,393)	(195,393)
2013	130,820	0%	35%	-	45,787	45,787
2013 50%	668,087	0%	35%	-	233,831	233,831
2014	(1,211,777)	0%	35%	-	(424,122)	(424,122)
2015	(149,473)	0%	35%	-	(52,315)	(52,315)
Reversal Non-TMI	(29,470,979)			**-**	**(10,445,884)**	**(10,445,884)**
Total Net Provison - Non-TMI				**-**	**12,294,223**	**12,294,223**

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service April, 2014 - April, 2015
Deferred Income Taxes Related to Gains/Losses

Vintage Year	Per Power Tax Report 52 Basis of Property	Accumulated Tax Depreciation	(Gain)/Loss recognized	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
	1	2	3	4	5	6 = 3 x 4	7 =3 x 5	8 = 6+7
Provision - 4/14-4/15								
1987	181,423	178,979	2,445	0%	35%	-	856	856
1988	191,025	186,830	4,195	0%	35%	-	1,468	1,468
1989	223,391	219,562	3,829	0%	35%	-	1,340	1,340
1990	238,097	231,323	6,774	0%	35%	-	2,371	2,371
1991	308,466	288,514	19,952	0%	35%	-	6,983	6,983
1992	271,570	261,868	9,703	0%	35%	-	3,396	3,396
1993	274,339	244,833	29,505	0%	35%	-	10,327	10,327
1994	250,165	225,632	24,533	0%	35%	-	8,587	8,587
1995	241,924	220,233	21,692	0%	35%	-	7,592	7,592
1996	154,881	131,985	22,897	0%	35%	-	8,014	8,014
1997	224,494	189,165	35,329	0%	35%	-	12,365	12,365
1998	267,265	221,318	45,948	0%	35%	-	16,082	16,082
1999	143,528	112,934	30,594	0%	35%	-	10,708	10,708
2000	213,433	166,963	46,470	0%	35%	-	16,264	16,264
2001	203,435	145,121	58,314	0%	35%	-	20,410	20,410
2001 30%	11,251	7,895	3,356	0%	35%	-	1,175	1,175
2002	45,827	34,112	11,715	0%	35%	-	4,100	4,100
2002 30%	86,630	56,836	29,794	0%	35%	-	10,428	10,428
2003	12,637	6,814	5,823	0%	35%	-	2,038	2,038
2003 30%	72,238	54,254	17,984	0%	35%	-	6,294	6,294
2003 50%	41,962	25,641	16,321	0%	35%	-	5,712	5,712
2004	(4,365)	3,104	(7,469)	0%	35%	-	(2,614)	(2,614)
2004 30%	90,256	52,147	38,109	0%	35%	-	13,338	13,338
2004 50%	55,924	31,875	24,049	0%	35%	-	8,417	8,417
2005	301,965	156,404	145,561	0%	35%	-	50,946	50,946
2006	328,674	157,369	171,305	0%	35%	-	59,957	59,957
2007	336,091	163,654	172,436	0%	35%	-	60,353	60,353
2008	107,837	43,072	64,765	0%	35%	-	22,668	22,668
2008 50%	147,507	58,457	89,050	0%	35%	-	31,168	31,168
2009	98,122	37,253	60,869	0%	35%	-	21,304	21,304
2009 50%	320,398	115,166	205,232	0%	35%	-	71,831	71,831
2010	6,694	5,258	1,436	0%	35%	-	503	503
2010 100%	-	-	-	0%	35%	-	-	-
2010 50%	156,471	50,689	105,782	0%	35%	-	37,024	37,024
2011	54,577	10,845	43,732	0%	35%	-	15,306	15,306
2011 100%	-	-	-	0%	35%	-	-	-
2011 50%	21,842	10,381	11,461	0%	35%	-	4,011	4,011
2012	29,169	4,268	24,901	0%	35%	-	8,715	8,715
2012 50%	223,501	31,300	192,201	0%	35%	-	67,270	67,270
2013	77,816	7,711	70,105	0%	35%	-	24,537	24,537
2013 50%	168,444	19,532	148,912	0%	35%	-	52,119	52,119
2014	100,037	14,212	85,825	0%	35%	-	30,039	30,039
Provision - Non-TMI (gains/losses)							733,403	733,403

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - TMI #2
Based upon Electric Plant in Service April, 2014 - April, 2015

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Deferral of Taxes State	Federal	Total
Provision				
1978	-	-	-	-
1979	-	-	-	-
1980	-	-	-	-
1981	108	-	38	38
1982	-	-	-	-
1983	-	-	-	-
1984	-	-	-	-
1985	-	-	-	-
1986	-	-	-	-
1987	-	-	-	-
1988	-	-	-	-
1989	-	-	-	-
1992	-	-	-	-
	108	-	38	38

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Deferral of Taxes State	Federal	Total
Reversal				
1978	47,719	-	22,905	22,905
1979	56,999	-	26,220	26,220
1980	118,371	-	54,450	54,450
1981	(3)	-	1,233	1,233
1982	-	-	225	225
1983	-	-	817	817
1984	-	-	389	389
1985	-	-	813	813
1986	-	-	292	292
1987	-	-	2,177	2,177
1988	-	-	(1)	(1)
1989	-	-	(1)	(1)
1992	-	-	(324)	(324)
	223,086	-	109,196	109,196

METROPOLITAN EDISON COMPANY
Summary of Deferred Income Taxes
Based upon Electric Plant in Service May, 2015 - April, 2016

		Deferral of Taxes		
	Vintage Year	State	Federal	Total
Provision:	1970	-	-	-
	1971	-	-	-
	1972	-	-	-
	1973	-	459	459
	1974	-	0	0
	1975	-	38	38
	1976	-	80	80
	1977	-	55	55
	1978	-	1,136	1,136
	1979	-	230	230
	1980	-	199	199
	1981	-	171	171
	1982	-	206	206
	1983	-	268	268
	1984	-	302	302
	1985	-	350	350
	1986	-	440	440
	1987	-	2,252	2,252
	1988	-	4,480	4,480
	1989	-	4,498	4,498
	1990	-	4,718	4,718
	1991	-	26,911	26,911
	1992	-	3,847	3,847
	1993	-	(200)	(200)
	1994	-	(568)	(568)
	1995	-	14,381	14,381
	1996	-	69,573	69,573
	1997	-	156,507	156,507
	1998	-	194,671	194,671
	1999	-	112,429	112,429
	2000	-	152,218	152,218
	2001	-	159,620	159,620
	2001 30%	-	6,093	6,093
	2002	-	26,783	26,783
	2002 30%	-	46,034	46,034
	2003	-	1,568	1,568
	2003 30%	-	26,020	26,020
	2003 50%	-	8,397	8,397
	2004	-	(3,326)	(3,326)
	2004 30%	-	48,681	48,681
	2004 50%	-	12,693	12,693
	2005	-	128,637	128,637
	2006	-	282,124	282,124
	2007	-	256,951	256,951
	2008	-	94,243	94,243
	2008 50%	-	36,844	36,844
	2009	-	107,970	107,970
	2009 50%	-	131,368	131,368
	2010	-	(6,253)	(6,253)
	2010 100%	-	-	-
	2010 50%	-	53,652	53,652
	2011	-	69,435	69,435
	2011 100%	-	-	-
	2011 50%	-	9,907	9,907
	2012	-	33,918	33,918
	2012 50%	-	238,042	238,042
	2013	-	102,234	102,234
	2013 50%	-	127,530	127,530
	2014	-	1,310,796	1,310,796
	2015	-	2,904,167	2,904,167
	2016	-	1,877,566	1,877,566
Total Provision		-	8,841,345	8,841,345

METROPOLITAN EDISON COMPANY
Summary of Deferred Income Taxes
Based upon Electric Plant in Service May, 2015 - April, 2016

		Deferral of Taxes		
	Vintage Year	State	Federal	Total
Reversal				
	1970	-	(1,797)	(1,797)
	1971	-	(6,201)	(6,201)
	1972	-	(5,540)	(5,540)
	1973	-	(5,932)	(5,932)
	1974	-	(6,307)	(6,307)
	1975	-	(2,939)	(2,939)
	1976	-	(27,094)	(27,094)
	1977	-	(5,680)	(5,680)
	1978	-	6,148	6,148
	1979	-	8,376	8,376
	1980	-	16,738	16,738
	1981	-	(37,034)	(37,034)
	1982	-	(40,260)	(40,260)
	1983	-	(66,768)	(66,768)
	1984	-	(64,795)	(64,795)
	1985	-	(98,292)	(98,292)
	1986	-	(108,896)	(108,896)
	1987	-	(110,694)	(110,694)
	1988	-	(113,404)	(113,404)
	1989	-	(131,748)	(131,748)
	1990	-	(151,549)	(151,549)
	1991	-	(148,229)	(148,229)
	1992	-	(146,362)	(146,362)
	1993	-	(146,582)	(146,582)
	1994	-	(135,448)	(135,448)
	1995	-	(104,984)	(104,984)
	1996	-	(91,467)	(91,467)
	1997	-	(138,071)	(138,071)
	1998	-	(168,603)	(168,603)
	1999	-	(103,278)	(103,278)
	2000	-	(126,940)	(126,940)
	2001	-	(123,454)	(123,454)
	2001 30%	-	(175)	(175)
	2002	-	(64,747)	(64,747)
	2002 30%	-	17,476	17,476
	2003	-	(64,688)	(64,688)
	2003 30%	-	10,106	10,106
	2003 50%	-	3,868	3,868
	2004	-	(103,351)	(103,351)
	2004 30%	-	(2,416)	(2,416)
	2004 50%	-	36,619	36,619
	2005	-	(16,229)	(16,229)
	2006	-	(194,785)	(194,785)
	2007	-	(231,514)	(231,514)
	2008	-	(116,315)	(116,315)
	2008 50%	-	(23,063)	(23,063)
	2009	-	(135,843)	(135,843)
	2009 50%	-	128,431	128,431
	2010	-	14,538	14,538
	2010 100%	-	(61,151)	(61,151)
	2010 50%	-	15,027	15,027
	2011	-	(393,293)	(393,293)
	2011 100%	-	(267,620)	(267,620)
	2011 50%	-	(41,994)	(41,994)
	2012	-	(43,799)	(43,799)
	2012 50%	-	(73,522)	(73,522)
	2013	-	13,645	13,645
	2013 50%	-	66,781	66,781
	2014	-	(197,903)	(197,903)
	2015	-	(82,441)	(82,441)
	2016	-	(16,191)	(16,191)
Total Reversal		-	(4,211,636)	(4,211,636)
Net Provision		-	4,629,710	4,629,710

METROPOLITAN EDISON COMPANY
Computation of Deferred Icome Taxes - Non - TMI
Based upon Electric Plant in Service May, 2015 - April, 2016

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
Provision						
1970	-	0%	35%	-	-	-
1971	-	0%	35%	-	-	-
1972	-	0%	35%	-	-	-
1973	1,310	0%	35%	-	459	459
1974	0	0%	35%	-	0	0
1975	109	0%	35%	-	38	38
1976	227	0%	35%	-	80	80
1977	158	0%	35%	-	55	55
1978	3,247	0%	35%	-	1,136	1,136
1979	657	0%	35%	-	230	230
1980	569	0%	35%	-	199	199
1981	463	0%	35%	-	162	162
1982	588	0%	35%	-	206	206
1983	765	0%	35%	-	268	268
1984	862	0%	35%	-	302	302
1985	1,001	0%	35%	-	350	350
1986	1,257	0%	35%	-	440	440
1987	5,705	0%	35%	-	1,997	1,997
1988	11,541	0%	35%	-	4,039	4,039
1989	11,721	0%	35%	-	4,102	4,102
1990	11,364	0%	35%	-	3,977	3,977
1991	71,021	0%	35%	-	24,857	24,857
1992	7,831	0%	35%	-	2,741	2,741
1993	(10,332)	0%	35%	-	(3,616)	(3,616)
1994	(9,199)	0%	35%	-	(3,220)	(3,220)
1995	35,853	0%	35%	-	12,549	12,549
1996	192,920	0%	35%	-	67,522	67,522
1997	438,449	0%	35%	-	153,457	153,457
1998	544,337	0%	35%	-	190,518	190,518
1999	313,108	0%	35%	-	109,588	109,588
2000	422,195	0%	35%	-	147,768	147,768
2001	439,512	0%	35%	-	153,829	153,829
2001 30%	16,461	0%	35%	-	5,761	5,761
2002	73,070	0%	35%	-	25,574	25,574
2002 30%	122,897	0%	35%	-	43,014	43,014
2003	2,670	0%	35%	-	935	935
2003 30%	69,036	0%	35%	-	24,162	24,162
2003 50%	19,176	0%	35%	-	6,711	6,711
2004	(6,900)	0%	35%	-	(2,415)	(2,415)
2004 30%	127,681	0%	35%	-	44,688	44,688
2004 50%	29,067	0%	35%	-	10,174	10,174
2005	323,204	0%	35%	-	113,121	113,121
2006	753,644	0%	35%	-	263,776	263,776
2007	681,107	0%	35%	-	238,388	238,388
2008	249,228	0%	35%	-	87,230	87,230
2008 50%	77,721	0%	35%	-	27,202	27,202
2009	289,835	0%	35%	-	101,442	101,442
2009 50%	312,154	0%	35%	-	109,254	109,254
2010	(17,999)	0%	35%	-	(6,300)	(6,300)
2010 100%	-	0%	35%	-	-	-
2010 50%	120,586	0%	35%	-	42,205	42,205
2011	184,631	0%	35%	-	64,621	64,621
2011 100%	-	0%	35%	-	-	-
2011 50%	24,876	0%	35%	-	8,707	8,707
2012	89,108	0%	35%	-	31,188	31,188
2012 50%	619,811	0%	35%	-	216,934	216,934
2013	270,374	0%	35%	-	94,631	94,631
2013 50%	319,073	0%	35%	-	111,676	111,676
2014	3,647,605	0%	35%	-	1,276,662	1,276,662
2015	8,265,759	0%	35%	-	2,893,016	2,893,016
2016	5,364,474	0%	35%	-	1,877,566	1,877,566
	24,525,590			-	8,583,957	8,583,957
Provison Gains/Losses Page (18)				**-**	**257,380**	**257,380**
Provision - Non -TMI				**-**	**8,841,336**	**8,841,336**

METROPOLITAN EDISON COMPANY
Computation of Deferred Icome Taxes - Non - TMI
Based upon Electric Plant in Service May, 2015 - April, 2016

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
Reversal						
1970	(3,758)	0%	48%	-	(1,797)	(1,797)
1971	(12,936)	0%	48%	-	(6,201)	(6,201)
1972	(11,758)	0%	47%	-	(5,540)	(5,540)
1973	(12,379)	0%	48%	-	(5,932)	(5,932)
1974	(13,164)	0%	48%	-	(6,307)	(6,307)
1975	(6,156)	0%	48%	-	(2,939)	(2,939)
1976	(56,473)	0%	48%	-	(27,094)	(27,094)
1977	(11,873)	0%	48%	-	(5,680)	(5,680)
1978	(5,309)	0%	48%	-	(2,524)	(2,524)
1979	(3,396)	0%	46%	-	(1,551)	(1,551)
1980	(8,464)	0%	46%	-	(3,878)	(3,878)
1981	(89,712)	0%	42%	-	(37,501)	(37,501)
1982	(99,677)	0%	40%	-	(40,345)	(40,345)
1983	(168,538)	0%	40%	-	(67,077)	(67,077)
1984	(167,378)	0%	39%	-	(64,943)	(64,943)
1985	(259,020)	0%	38%	-	(98,599)	(98,599)
1986	(297,546)	0%	37%	-	(109,007)	(109,007)
1987	(319,571)	0%	35%	-	(111,519)	(111,519)
1988	(326,233)	0%	35%	-	(113,404)	(113,404)
1989	(378,646)	0%	35%	-	(131,747)	(131,747)
1990	(436,982)	0%	35%	-	(151,549)	(151,549)
1991	(425,403)	0%	35%	-	(148,229)	(148,229)
1992	(417,870)	0%	35%	-	(146,239)	(146,239)
1993	(418,805)	0%	35%	-	(146,582)	(146,582)
1994	(386,994)	0%	35%	-	(135,448)	(135,448)
1995	(299,955)	0%	35%	-	(104,984)	(104,984)
1996	(261,333)	0%	35%	-	(91,467)	(91,467)
1997	(394,489)	0%	35%	-	(138,071)	(138,071)
1998	(481,724)	0%	35%	-	(168,603)	(168,603)
1999	(295,081)	0%	35%	-	(103,278)	(103,278)
2000	(362,686)	0%	35%	-	(126,940)	(126,940)
2001	(352,725)	0%	35%	-	(123,454)	(123,454)
2001 30%	(500)	0%	35%	-	(175)	(175)
2002	(184,992)	0%	35%	-	(64,747)	(64,747)
2002 30%	49,931	0%	35%	-	17,476	17,476
2003	(184,822)	0%	35%	-	(64,688)	(64,688)
2003 30%	28,873	0%	35%	-	10,106	10,106
2003 50%	11,052	0%	35%	-	3,868	3,868
2004	(295,290)	0%	35%	-	(103,351)	(103,351)
2004 30%	(6,901)	0%	35%	-	(2,416)	(2,416)
2004 50%	104,624	0%	35%	-	36,619	36,619
2005	(46,369)	0%	35%	-	(16,229)	(16,229)
2006	(556,529)	0%	35%	-	(194,785)	(194,785)
2007	(661,468)	0%	35%	-	(231,514)	(231,514)
2008	(332,330)	0%	35%	-	(116,315)	(116,315)
2008 50%	(65,895)	0%	35%	-	(23,063)	(23,063)
2009	(388,122)	0%	35%	-	(135,843)	(135,843)
2009 50%	366,946	0%	35%	-	128,431	128,431
2010	41,536	0%	35%	-	14,538	14,538
2010 100%	(174,718)	0%	35%	-	(61,151)	(61,151)
2010 50%	42,935	0%	35%	-	15,027	15,027
2011	(1,123,693)	0%	35%	-	(393,293)	(393,293)
2011 100%	(764,627)	0%	35%	-	(267,620)	(267,620)
2011 50%	(119,982)	0%	35%	-	(41,994)	(41,994)
2012	(125,140)	0%	35%	-	(43,799)	(43,799)
2012 50%	(210,061)	0%	35%	-	(73,522)	(73,522)
2013	38,986	0%	35%	-	13,645	13,645
2013 50%	190,804	0%	35%	-	66,781	66,781
2014	(565,438)	0%	35%	-	(197,903)	(197,903)
2015	(235,546)	0%	35%	-	(82,441)	(82,441)
2016	(46,260)	0%	35%	-	(16,191)	(16,191)
Reversal Non-TMI	(11,999,033)			-	(4,252,981)	(4,252,981)
Total Net Provison - Non-TMI				**-**	**4,588,355**	**4,588,355**

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service May, 2015 - April, 2016
Deferred Income Taxes Related to Gains/Losses

Vintage Year	Per Power Tax Report 52 Basis of Property	Accumulated Tax Depreciation	(Gain)/Loss recognized	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
	1	2	3	4	5	6 = 3 x 4	7 =3 x 5	8 = 6+7
Provision - 5/15-4/16								
1987	61,111	60,381	731	0%	35%	-	256	256
1988	64,346	63,088	1,257	0%	35%	-	440	440
1989	75,248	74,118	1,130	0%	35%	-	396	396
1990	80,202	78,085	2,117	0%	35%	-	741	741
1991	103,905	98,037	5,868	0%	35%	-	2,054	2,054
1992	91,477	88,317	3,160	0%	35%	-	1,106	1,106
1993	92,410	82,647	9,762	0%	35%	-	3,417	3,417
1994	84,267	76,691	7,576	0%	35%	-	2,652	2,652
1995	81,491	76,257	5,234	0%	35%	-	1,832	1,832
1996	52,171	46,312	5,859	0%	35%	-	2,050	2,050
1997	75,620	66,904	8,715	0%	35%	-	3,050	3,050
1998	90,027	78,161	11,866	0%	35%	-	4,153	4,153
1999	48,347	40,228	8,119	0%	35%	-	2,841	2,841
2000	71,894	59,181	12,713	0%	35%	-	4,449	4,449
2001	68,526	51,981	16,545	0%	35%	-	5,791	5,791
2001 30%	3,790	2,842	947	0%	35%	-	332	332
2002	15,437	11,985	3,452	0%	35%	-	1,208	1,208
2002 30%	29,181	20,553	8,628	0%	35%	-	3,020	3,020
2003	4,257	2,446	1,811	0%	35%	-	634	634
2003 30%	24,333	19,027	5,306	0%	35%	-	1,857	1,857
2003 50%	14,135	9,319	4,816	0%	35%	-	1,686	1,686
2004	(1,470)	1,132	(2,602)	0%	35%	-	(911)	(911)
2004 30%	30,402	18,994	11,409	0%	35%	-	3,993	3,993
2004 50%	18,838	11,639	7,198	0%	35%	-	2,519	2,519
2005	101,715	57,385	44,330	0%	35%	-	15,515	15,515
2006	110,712	58,289	52,423	0%	35%	-	18,348	18,348
2007	113,210	60,172	53,039	0%	35%	-	18,564	18,564
2008	36,324	16,285	20,039	0%	35%	-	7,014	7,014
2008 50%	49,687	22,138	27,549	0%	35%	-	9,642	9,642
2009	33,052	14,402	18,650	0%	35%	-	6,527	6,527
2009 50%	107,925	44,741	63,184	0%	35%	-	22,114	22,114
2010	2,255	2,122	133	0%	35%	-	46	46
2010 100%	-	-	-	0%	35%	-	-	-
2010 50%	52,706	20,000	32,707	0%	35%	-	11,447	11,447
2011	18,384	4,630	13,754	0%	35%	-	4,814	4,814
2011 100%	-	-	-	0%	35%	-	-	-
2011 50%	7,358	3,929	3,429	0%	35%	-	1,200	1,200
2012	9,826	2,026	7,800	0%	35%	-	2,730	2,730
2012 50%	75,285	14,976	60,309	0%	35%	-	21,108	21,108
2013	26,212	4,488	21,724	0%	35%	-	7,603	7,603
2013 50%	56,739	11,441	45,298	0%	35%	-	15,854	15,854
2014	119,456	21,928	97,528	0%	35%	-	34,135	34,135
2015	37,138	5,277	31,861	0%	35%	-	11,151	11,151
Provision - Non-TMI (gains/losses)							257,380	257,380

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - TMI #2
Based upon Electric Plant in Service May, 2015 - April, 2016

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Deferral of Taxes State	Federal	Total
Provision				
1978	-	-	-	-
1979	-	-	-	-
1980	-	-	-	-
1981	26	-	9	9
1982	-	-	-	-
1983	-	-	-	-
1984	-	-	-	-
1985	-	-	-	-
1986	-	-	-	-
1987	-	-	-	-
1988	-	-	-	-
1989	-	-	-	-
1992	-	-	-	-
	26	-	9	9

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Deferral of Taxes State	Federal	Total
Reversal				
1978	18,068	-	22,814	8,673
1979	21,582	-	26,116	9,928
1980	44,819	-	54,235	20,617
1981	25	-	1,229	467
1982	-	-	224	85
1983	-	-	814	309
1984	-	-	387	147
1985	-	-	810	308
1986	-	-	291	111
1987	-	-	2,168	824
1988	-	-	(1)	(0)
1989	-	-	(1)	(0)
1992	-	-	(322)	(123)
	84,494	-	108,764	41,345

METROPOLITAN EDISON COMPANY
($000)

POST 1969 VINTAGES

	Per Power Tax	Pro Forma Under Present Rates Normalization Adjustment	Total
Liberalized Depreciation Deferred Taxes			
Balance per Budget 3/31/14	(460,362)		(460,362)
Balance per Budget 3/31/13	(447,575)		(447,575)
Liberalized Depreciation Activity - April, 2013 to March, 2014	(12,787)		(12,787)
Net Federal and State Provision	12,787		12,787
Less: Net State Provision (negative)	(1,279)		(1,279)
Net Federal Provision per Budget	14,066		14,066
Add: Federal Benefit (increase) of State	(448)		(448)
Net Federal - April, 2013 to March, 2014 Provision for Rates	13,618		13,618

POST 1969 VINTAGES

	Per Power Tax	Pro Forma Under Present Rates Normalization Adjustment	Total
Liberalized Depreciation Deferred Taxes			
Balance per Budget 4/30/15	(472,793)		(472,793)
Balance per Budget 3/31/14	(460,362)		(460,362)
Liberalized Depreciation Activity - April, 2014 to April, 2015	(12,431)		(12,431)
Net Federal and State Provision	12,431		12,431
Less: Net State Provision (negative)	43		43
Net Federal Provision per Budget	12,388		12,388
Add: Federal Benefit (increase) of State	15		15
Net Federal - April, 2014 to April, 2015 Provision for Rates	12,403		12,403

POST 1969 VINTAGES

	Per Power Tax	Pro Forma Under Present Rates Normalization Adjustment	Total
Liberalized Depreciation Deferred Taxes			
Balance per Budget 4/30/16	(477,639)		(477,639)
Balance per Budget 4/30/15	(472,793)		(472,793)
Liberalized Depreciation Activity - May, 2015 to April, 2016	(4,846)		(4,846)
Net Federal and State Provision	4,846		4,846
Less: Net State Provision (negative)	332		332
Net Federal Provision per Budget	4,514		4,514
Add: Federal Benefit (increase) of State	116		116
Net Federal - May, 2015 to April, 2016 Provision for Rates	4,630		4,630

Reconciliation of the Deferred Tax Balance Shown on the Rate Base and the Deferred Tax Balance on the Balance Sheet

	Met-Ed
Balance Sheet (RAD-54) @ 3/31/13	542,609
Total APB11 Deferreds on Rollforward Schedule @ 3/31/13	462,669
Difference	79,940
Reconciling Items:	
State Deferreds	-
3/31/13 Rollforward Schedule didn't tie to SAP	-
FAS 109 Gross-Up	-
FAS 109	79,940
Total Reconciling Items	79,940
Balance Sheet (RAD-54) @ 3/31/14	555,752
Adjustments needed for RAD-35	994
Adjusted Balance Sheet (RAD-35) @3/31/14	556,746
Total APB11 Deferreds on Rollforward Schedule @ 3/31/14	478,696
Difference	78,050
Reconciling Items:	
State Deferreds	-
State Offset Deferreds	-
FAS 109 Gross-Up	-
FAS 109	77,056
Smart Meters per RAD-35	310
Vegetation Management FERC Reclasses	684
Total Reconciling Items	78,050
Balance Sheet (RAD-54) @ 3/31/15	552,220
Adjustments needed for RAD-35	17,014
Adjusted Balance Sheet (RAD-35) @3/31/15	569,234
Total APB11 Deferreds on Rollforward Schedule @ 4/30/15	489,924
Difference	79,310
Reconciling Items:	
State Deferreds	-
State Offset Deferreds	-
B/S one month behind Rollforward Schedule	(864)
Smart Meters per RAD-35	996
Deferred Tax Pro-Ration on Rollforward Schedule	640
FAS 109 Gross-Up	-
FAS 109	78,538
Total Reconciling Items	79,310

Balance Sheet (RAD-54) @ 4/30/16	552,440
Adjustments needed for RAD-35	38,087
Adjusted Balance Sheet (RAD-35) @4/30/16	590,527
Total APB11 Deferreds on Rollforward Schedule @ 4/30/16	495,161
Difference	95,366
Reconciling Items:	
State Deferreds	-
State Offset Deferreds	-
B/S one month behind Rollforward Schedule	864
Smart Meters per RAD-35	2,037
Deferred Tax Pro-Ration on Rollforward Schedule	6,748
FAS 109 Gross-Up	0
FAS 109	85,717
Total Reconciling Items	95,366

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-25:

"Submit a schedule showing a breakdown of accumulated and unamortized investment tax credits, by vintage year and percentage rate, together with calculations supporting the amortized amount claimed as a reduction to pro forma income taxes. Provide details of methods used to write-off the unamortized balances."

RESPONSE:

Investment Tax Credit Balances, Provision and Amortization
($000)

	4% and 10%
Balance 3/31/13	$ 5,919
12 Months ended 3/31/14 Amortization	(398)
Balance 3/31/14	$ 5,521
12 Months ending 3/31/15 Amortization	(364)
Balance 3/31/15	$ 5,157
Amortization 1 month ending 4/30/15	(31)
Balance 4/30/15	$ 5,126
12 Months ending 4/30/16 Amortization	(364)
Balance 4/30/16	$ 4,762

Investment Tax Credit

Met-Ed is amortizing the deferred credit previously created by a ratable flow-through to income over the useful life of the property. On March 9, 1972, General Public Utilities Corporation (former parent company of respondent) filed with the District Director of Internal Revenue, Manhattan District, on behalf of its affiliated companies (Met-Ed being one of the affiliates), an election under paragraph (2) of Section 46(e) of the Internal Revenue Code of 1954, as amended, for allowance, with respect to public utility property, of the credit allowed by Section 38 of the Code. Such an election provides (a) to reduce the cost of service for ratemaking purposes or in its regulated books of account by no more than ratable portion of the credit allowable by Section 38, and (b) not to reduce the base to which its rate of return is applied for ratemaking purposes by any portion of the credit allowable by Section 38.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-26:

"Explain in detail by statement or exhibit the appropriateness of claiming any additional items, not otherwise specifically explained and supported in the statement of operating income."

RESPONSE:

The appropriateness of claiming the various items included in the statement of operating income is explained in the supporting schedules to Met-Ed Exhibit RAD-2 and the testimony and exhibits of the Company's witnesses.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-27:

"If the utility's operations include non-jurisdictional activities, provide a schedule which demonstrates the manner in which rate base and operating income date have been adjusted to develop the jurisdictional test year claim."

RESPONSE:

The Company does not maintain its books based on jurisdictional divisions. An allocation for PaPUC jurisdictional purposes will be supported by Met-Ed witness Hillary E. Stewart, Met-Ed Statement No. 5 through the cost of service study.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-E-1:

"Supply a copy of any budget utilized as a basis for any test year claim, and explain the utility's budgeting process."

RESPONSE:

The FirstEnergy budget guidelines details the items required for the preparation of the construction and operating budgets. See Met-Ed RAD-45 Attachment A for a review of the guidelines.

Beginning in 2014, FirstEnergy implemented a new budget and long-term planning application, UI Planner. See Met-Ed Exhibit RAD-45 Attachment B for an explanation of FirstEnergy's budget process.

A copy of the budget utilized for the test year claim is contained in Met-Ed Exhibit RAD-18.

FirstEnergy

2014 Budget Guidelines



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CHAPTER 1: INTRODUCTION

The integrated business planning process is critical to the success of FirstEnergy. A key component of this process is the annual budget which provides a method to quantify and report the current year's expectations and helps drive the enterprise toward achieving both short-term and long-term financial and operational objectives. The budget also helps facilitate the efficient usage of the Company's financial resources and allows us to measure actual performance against projections.

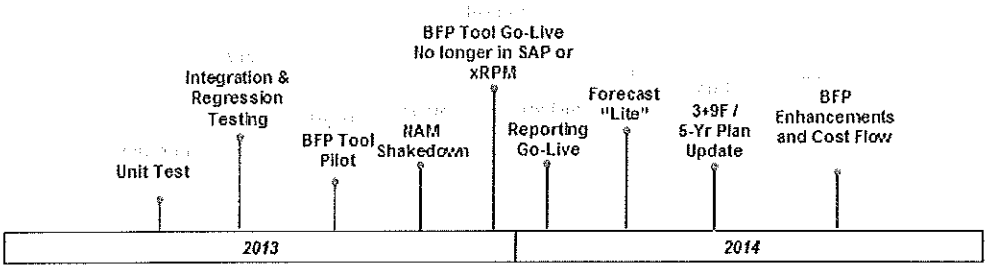
The guidelines in this booklet are intended to assist persons responsible for direct input of data into the SAP system as they prepare the 2014 annual budget. The 2014 budget should be based on your business unit's business plans and should align with Executive Council's expectations.

Business Unit Income Statements will be produced using the Profit Center Accounting module in SAP. Budget details will be developed and input using the various SAP cost collectors (i.e. cost centers, internal orders and WBSs). Through system mapping within SAP, these cost collectors are assigned to Profit Centers. Once data input is completed and the SAP system is closed, Business Unit Income Statements will be available for review. The Profit Center Hierarchy (PC0001B) serves as the source for the structure of Business Unit Income Statements). Earnings Driver reports which measure the impact and contribution of key items to the financial performance of each Business Unit will also be produced. Any questions concerning these statements should be directed to Mike Kreighbaum (825-2556) or Carrie Wokaty (825-6005).

Please Note: ***For the 2014 Forecast and the 2014 Annual Budget we will follow the same process as last year in SAP.*** *However, as part of the Financial Transformation project, we will be implementing the new Cost Accountability Model and begin doing our forecasting and budget inputs into a new financial tool, UIPlanner. Separate documentation and training for the tool will be provided through the FiT team. Below is a high level summary of the upcoming implementation timeline.*

Financial Transformation Project

Path to Implementation



Resource Activities	Date	Time Commitment
Training	August 20 – 22	~ 24 hours
BFP Pilot	Sept 2 – Oct 28	~ 10/week
Acct Model Shakedown	Sept 9 – Oct 28	~ 16/week
Train the Organization	November	~ 24 hours
Update End-User Queries	November - December	Varies
Assist with rollout	Dec - Jan	Varies

Note: 2014 budget documentation can be found in U:\Public\Budget Info\2014 Budget

Overview For Budget Input

Planning Must Be Done For The Following:
➢ Gross Payroll (Dollars)
➢ Staffing Level (Headcount) – Coordinate with IBP-Business Services and Workforce Planning
➢ Other – Than – Labor (OTL)
➢ Activity Input Planning (Hours to Cost Centers, WBSs and Internal Orders)
Versions
Annual Budget: ➢ 2014 Budget detail planning will be **input** in Version 20 ➢ 2014 Final Closed detail budget will be in Version 12 unless otherwise noted

Calendar of Events

The 2014 Forecast Schedule

Activity	Completion Date
➢ **SAP 2014 V20 Opens**	7/29/2013
➢ **Complete Headcount & Gross Payroll**	8/30/2013
➢ **All Revenues & Expenses updated to calculate deferrals**	9/6/2013
➢ **Lock SAP V20 @ 5 p.m.**	9/13/2013
➢ **IBP/Gen Accounting process 2014 Budget V13**	9/16 – 9/20/2013
➢ **Business Units to begin validation of results**	9/20/2013

Dates for the final budget will be announced after the forecast is completed.

The 2014 Budget Schedule

Activity: Business Units enter 2014 Detail Budgets	Completion Date
➢ **Gross Payroll Input Complete**	TBD
➢ **Headcount Input Complete**	TBD
➢ **HR Benefits Complete**	TBD
➢ **Revenues/Expenses Impacting Deferrals & Amortizations (Including Inter-Company Transactions)**	TBD
➢ **Transmission Revenues & Expenses**	TBD
➢ **Inter-company Transactions Input Complete**	TBD
➢ **Lockdown of SAP system**	TBD

THESE DATES ARE SUBJECT TO CHANGE

Throughout the budget cycle you should expect to receive communications as needed to ensure the schedule is met. The purpose of these communications will be to help individuals manage budgeting activities, ensure mid-process completion goals are met, and address any issues that arise during the budget entry period.

CHAPTER 2: LABOR

Straight Time Payroll

Straight time payroll for the 2014 Budget will be developed and input by the Business Units. The budget is based on projected staffing levels and estimated employee salaries based on a regular weekly schedule of 40 hours per week per full-time employee
Adjustments should be made for changes in payroll due to attrition, retirements, promotions, demotions, and all salary adjustments including general wage rate increases. **Annual wage rate increases need to be applied by the Business Units, based on the appropriate rate change and timing.** The assumed wage rate for non-bargaining employees is 3.0%. The non-bargaining WRI should be assumed to be effective September 1, 2014. For bargaining unit employees, the bargaining unit WRI is based on the terms of each union contract.

The monthly spread of straight time labor should be based on the number of pay weeks in each month according to the Payroll Calendar. Distribution key(s) for the monthly distribution of payroll are noted below for bi-weekly payroll and in the Reference Material Section for the weekly payroll. Keep in mind, the distribution keys are only used to spread the monthly data and **do not** increase the yearly or monthly totals for the wage rate increases. The budget preparer needs to calculate the annual payroll and inflate it for any expected WRI, then use the appropriate distribution key to spread the payroll. **Payroll must be spread by month, not summed and input into one month.**

The appropriate general ledger accounts/cost elements for Straight Time Labor:

Straight Time Payroll

520010	Payroll - Straight Time - Bargaining
520050	Payroll - Straight Time - Non-Bargaining
520051	Payroll - Straight Time - Temporary Help
520062	Payroll - Straight Time Coop Students
520063	Payroll - Straight Time-Part Time-Non-Barg
520064	Payroll - Straight Time-Part Time-Bargaining

NOTE: If a Business Unit(s) has a question about developing its straight time payroll estimates or the input of the dollars into SAP (including the appropriate spreads and wage rate increases), please contact Corporate Budgets and Forecasts before the Gross Payroll entry deadline. (See Key Contacts page 27)

Payroll Calendar Information:

2014 Bi-Weekly payroll

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Weeks	4	4	6	4	4	4	4	6	4	4	4	4	52
Hours	160	160	240	160	160	160	160	240	160	160	160	160	2080

Distribution Keys **P14S and P14B** both use this spread pattern. The P13B Distribution Key assumes a 3% March wage increase, while **P14S** assumes a 3% wage increase in September.

2014 Weekly payroll

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec	Total
Weeks	4	4	5	4	5	4	4	5	4	4	5	4	52
Hours	160	160	200	160	200	160	160	200	160	160	200	160	2080

For weekly payroll, refer to the list of Distribution Keys in the Reference Material Section (Chapter 7) for the distribution key that spreads payroll based on the effective month of the WRI. If additional distribution keys are needed, contact Corporate Budgets and Forecasts.

Overtime Payroll

Costs associated in a given pay week for work exceeding 40 hours. The addition of overtime dollars to the budget should be planned and approved accordingly. Planning for all overtime will be completed by the business units using the appropriate cost elements:

520110 Payroll - Overtime Bargaining
520150 Payroll - Overtime Non Bargaining
520151 Payroll - Overtime Temporary Help
520162 Payroll - Overtime Co-Op Student
520163 Payroll - Overtime Part Time Non Barg
520164 Payroll - Overtime Part Time Bargaining

Payroll Overheads

Payroll Overheads – Employee Benefits, Incentive Comp and Payroll Taxes will be applied as an overhead during the closing process. The rates will be determined by General Accounting and input into the SAP costing sheets after final payroll is determined and all gross benefit costs (medical, dental, prescription drug etc.) are input into the HR benefit cost centers.

Employee Benefits – Benefit costs *will be developed by Human Resources/Corp Budgets & Forecasts* and input into the Special Purpose Ledger (SPL) in HR benefit cost centers using the appropriate primary cost elements. Pension and OPEB costs are not included in the Employee Benefits overhead calculation but are applied to capital work as specific capital overheads.

The secondary cost element 850070 – Payroll Overhead Benefits – Straight Time will be used to apply the Benefit overhead on straight time payroll during the budget closing process.

Payroll Taxes - *will be budgeted by Corporate Budgets and Forecasts* and input into the SPL in Special Tax cost centers.

The secondary cost element 850080 – Payroll Overhead – Taxes will be used to apply the Payroll Tax overhead on straight time and overtime payroll during the closing process.

Incentive Comp - *will be budgeted by Human Resources/Corp Budgets and Forecasts* and input into the SPL in Special Incentive Comp cost centers.

The secondary cost element 850090 – Incentive Comp will be used to apply the Incentive Comp overhead on straight time and overtime payroll during the closing process.

Payroll Related Items

Other payroll related general ledger accounts/cost elements:

520019 Payroll Retention Bonuses – Budgeted by the Business Unit granting the bonus
520165 Payroll Accrual (Budgeted only by General Accounting)
520250 Payroll Bonuses - Represents annual bonuses and other bonuses awarded throughout the year for special circumstances and are the responsibility of the Business Units
520260 Payroll Additional Comp – MGRK (Budgeted by Business Units where appropriate)
520300 Payroll Restricted Stock (Budgeted only by HR/Corporate Budgets and Forecasts)
520400 Payroll Severance – (Budget only by HR/Corporate Budgets and Forecasts)
520500 Payroll Adjustments to Gross - Examples include retro pay, grievance settlements, remote reporting costs, and relocation expenses not covered by HR (See Relocation Policy found on the Services & Support section of the FirstPlace Portal).

SAP INPUT – TRANSACTIONS OVERVIEW for GROSS PAYROLL
Set Planner Profile => Transaction KP04
Profile = FE-CO01
Planning Input => Transaction KP06
Layout = CC Primary No Excel or CC Prime – Y4

Note: Under no circumstance, should any of the payroll-related costs listed, including straight time, overtime, or bonuses be budgeted directly in the SPL via Transaction GP12N. Transaction KP06 should be used.

Staffing

Staffing levels (Headcount) **must be input by month**, by individual Cost Center, using Statistical Key Figures (SKFs) – transaction KP46. Budget all full-time, part-time, and temporary FE employees on SAP Payroll. **New employees should be budgeted in the month in which they will start.** Do not include contractor/non-FE employees and do not assume all hires begin the month of January. The following SKFs should be used:

	Bargaining	Non-Bargaining
Full-Time	EMPFTB	EMPFTN
Part-Time	EMPPTB	EMPPTN
Temporary	EMPTPB	EMPTPN
Student Intern	EMPSIB	EMPSIN

SAP INPUT – TRANSACTIONS OVERVIEW for STATISTICAL KEY FIGURES
Set Planner Profile => Transaction KP04
Profile = FE-CO01
Planning Input => Transaction KP46
Layout = CCTR STAT Key Fig PL or SKF – Y4

Budget Tip: After input of staffing levels and payroll dollars is complete, check that the monthly payroll totals are consistent with the monthly headcount projections.

Activity Input Planning (Hours)

Payroll costs can be moved from the employee or responsible cost centers to a target or receiving cost collector (Cost Center, Order or WBS element) by planning productive hours by activity type. The activity price associated with each cost center/activity type combination is calculated and input by Corporate Budgets and Forecasts. These activity prices are then used to produce the standard labor activity allocations.

Unproductive Time – Planning for unproductive time (i.e. sick time, safety meetings, union business, etc.) is not required. These costs remain in the responsible cost center and the unproductive hours and associated costs are incorporated in the calculation of the activity prices.

SAP INPUT – TRANSACTIONS OVERVIEW for ACTIVITY INPUT PLANNING (HOURS)

Set Planner Profile => Transaction KP04
Profile for Hrs charged to Cost Centers = FE-CO01
Profile for Hrs charged to Int. Order = FE-CO01
Profile for Hrs charged to WBS Elem = TD-PS01 or GEN-FRMF or GEN-FRMN

Planning Input =>
Cost Centers => Transaction KP06
Layout = CC Act Inp No Excel or CC – Act – Y4
Int. Orders => Transaction KPF6
Layout = OR Act Inp No Excel or OR – Act- Y4
WBS Elem => Transaction CJR2
Layout = Act Input or WBS – Act – Y4

CHAPTER 3: OTHER THAN LABOR (OTL)

All input into the SAP system for non-labor items is entered in Special Purpose Ledger Z9 using transaction GP12N – Change Plan Data - Special Purpose Ledger.

All transactions for non-labor items must contain:

Responsible Cost Center
Cost Element
Target Cost Collector – Cost Center, Order, Network or WBS element
Target Cost Collector Type – (KS, OR, PR)
Cost Type (Capital, O&M, Other)

Responsible Cost Center for Other-Than-Labor is defined as the Cost Center with budget responsibility for the expenditure.

All OTL input into the Special Ledger must be entered as company SC00.

Cost Types are defined as follows:

Type 1 Capital - Capital is planned to WBS Elements. WBS Elements are defined as Cost Type 1 if they settle to:

107XXX Construction Work In Progress
108XXX Retirement Work In Progress
Capitalized Nuclear Fuel Accounts
CWIP and RWIP for Non-Utility assets

Type 2 O&M (Income Statement Accounts)

Type 2 is any cost that settles to a Cost Center and becomes part of the Income Statement (predominately O&M but includes revenues, interest income, depreciation etc.)

Type 3 Other

Type 3 charges are any costs that settle to Balance Sheet accounts and are not considered Capital.

SAP INPUT – TRANSACTIONS OVERVIEW FOR OTL
Set Planner Profile => Transaction GLPLSET
Profile = ZZSPL902
Planning Input => Transaction GP12N
Layout = ZZSPL90 or ZZSPL90 – Y4

Guidelines for General Business Items:

Office Supplies – Cost Element 540100
Stationary type items purchased through Staples or similar vendor, e.g., annual planners and calendars, etc. The budget should be at the department/plant level rather than the cost center level to maintain consistency and control within the business unit.

Telecommunications Equipment and Service – Cost Element 590000
Costs associated with Company approved/provided cellular telephone equipment and associated monthly cellular charges are to be budgeted by cellular user's business unit.

- Basic cellular voice/text service - $50 monthly per telephone.
- Smartphone (iPhone) - $100 monthly per telephone.
- Cellular broadband data service (laptop and MiFi's/HotSpot) - $55 monthly per device.

Business Units should refer to the Computer Peripherals Price List (page 11) to budget for costs associated with purchase of the cellular equipment.

Copies/Multi-functional devices (MFD), Printers, Faxes
Copier/MFD and printer equipment along with maintenance and supplies for general office use are budgeted by IT. Plotter purchase/lease, specialty copiers or printers, fax machines, and associated service/supply costs are to be budgeted by the responsible Business Unit. For special projects, short-term needs, and plant outages the cost for copy, fax, and print devices are to be budgeted by the responsible Business Unit. Contact IT to determine if existing devices may be redeployed for short term needs.
Budget printer equipment to G/L 580020, supplies to 560200, and maintenance to 550300.
Budget copier equipment to G/L 570052, supplies and maintenance to 560200.
Budget fax equipment and supplies to G/L 560200, maintenance to 550300.

Employee Expenses – Cost Element 540000
Miscellaneous expenses as a result of conducting company business not captured in other cost elements and reimbursed through an employee expense report.

Employee Meals – Cost Element 540010
Expensed meals as a result of company business.

Emergency Employee Expense / No Meals – Cost Element 540015
Miscellaneous expenses that were incurred unexpectedly (call-outs, storms, and outages).

Travel Expenses – Cost Element 540101
Expenses incurred while traveling on company business that are not reimbursed through employee expense reports. Each business unit should budget for use of the corporate jet by their employees at the rate of $220 per "one way trip". Example: For one person flying from Akron to Morristown, $220 is charged to the employee's responsible cost center. Persons budgeting for Executive travel will be provided more detailed information separately from these guidelines.

Per Diem – Cost Element 540102
Fixed rate for change in work location, outages, etc. Often used in lieu of meals and possibly other related employee expenses.

Travel Expenses – Corp Jet – Cost Element 540106
Costs associated with use of corporate jet. This cost element is used exclusively by the Flight Operations Group.

Employee Expense – Training – Cost Element 540020
External seminar fees and associated external training expenses.

Training Student Expenses – Cost Element 540103
Student training fees for internal courses coordinated by Human Resources.

Postage – Cost Element 650100
All non-customer mailings/billings, including large packages (UPS, FedEx, Overnight Express, etc) should be budgeted by each Business Unit. Postage for customer related mailings and billings should be budgeted by the Customer Service bill production cost centers.

Other Items:

Application Software Maintenance – Business application software maintenance will be budgeted by IT Business Unit Support. Portfolio Managers will be contacting your department to coordinate budget information and ensure that all maintenance fees are captured.

Banked Vacation – The payout of banked vacation ***should not be budgeted*** by the individual cost centers. It is budgeted by Human Resources/Corp Budgets/Forecasts.

Claims (Payable and Receivable) – The ED Operating Companies should budget for (payable) claims and lawsuits related to distribution facilities (including personal injury, property damage, and vegetation management claims), fleet vehicle accidents, and environmental injuries (such as asbestos) for historical ownership of generating plants, as well as the legal fees and other administrative costs to defend against such claims and lawsuits. The ED Operating Companies should also budget for damages caused to their respective distribution facilities by outside parties; applying offsets by taking into consideration historical recovery amounts achieved through (receivable) claims activities. Generating Plants should budget for anticipated (payable) claims and lawsuits related to their facilities, as well as the legal fees and other administrative costs to defend against such claims and lawsuits.

Company Facilities – Real Estate and Facilities will budget for the maintenance and service contracts for Corporate, FENOC and Fossil. Energy Delivery will budget for all Utility Company facilities. The WBS structure will be utilized for both budgeting and tracking of O&M spend. Budgets will be established using a WBS and WBS Element / Service Categories:

- Landscaping
- Janitorial
- Building Maintenance
- Waste Removal
- Paving repairs
- Elevators
- HVAC
- Roof repairs
- Electrical
- Mechanical Equipment
- Fire Protection
- Construction
- Fences
- Plumbing
- Painting
- Pest Control
- Utilities
- Snow Removal

- Costs will be segregated by line of business (Corporate, FENOC, Fossil, and ED Operating Company)
- Monthly reporting of actuals will include the WBS, the Service Category and Building Cost Center
- This will allow for a direct comparison of Budget to actual spend enabling a monthly view of actuals versus budget.

Real Estate will budget for all building and land leases.

Corporate membership dues and fees, contributions and donations – It is the Company's policy to enter into and maintain Corporate memberships in organizations deemed necessary to maintain

professional expertise in various aspects of the Company's operations and to establish and maintain relationships with selected organizations with whom we share common interests.
Corporate memberships will be budgeted and processed through the Contributions Department. The company should not pay dues for an employee's individual membership unless the membership is held at the Company's specific request. When this is the case, the dues and any fees or assessments associated with membership should be budgeted in the employee's administrative cost center. Contributions will also be budgeted through the Contributions Department, working with Operating Company management and the Corporate Affairs staff.

Desktop Computer Hardware and Software – Standard PC workstations and laptops are budgeted in IT Client Support based on a fixed replacement cycle (5 years for desktops, 3 years for laptops). **Peripheral equipment is not budgeted in IT.** All peripheral equipment requires director approval, will be ordered by the business unit (not IT) using a specific web site, **and should be budgeted as a purchase in the requesting business unit cost center**. Listed below are some commonly requested peripherals with pricing where applicable.

Computer Peripherals Price List:

Display Options	Description	Vendor / Model	Approximate Cost
For Laptops	Monitors not provided for laptops		n/a
For Desktops	17 inch CRT provided for desktops upon failure of previous unit	See HP or SHI catalog on portal for options.	
Cellular	**Description**	**Vendor / Model**	**Approximate Cost**
Cellular voice/text	Basic cellular handset and standard accessories.	First Communications	$30
iPhone	iPhone and standard accessories.	AT&T, Sprint, Verizon Wireless	$150
Data – MiFi/Hot Spot	Data device.	AT&T, Sprint, Verizon Wireless	$80 - $130
Laptop Options	**Description**	**Vendor / Model**	**Approximate Cost**
Port Replicator for nc8440p/8540p/8460/8470	Part # A7E34AA#ABA	HP	$130
Plotters	**Description**	**Vendor / Model**	**Approximate Cost**
Standard HP Plotter Purchase	Wide Format plotter/printer purchase and install	HP	$6,800
Standard HP Plotter Service	Annual service for HP Plotter	Print Service Provider	$1,654

Educational Assistance – Human Resources/Corp Budgets/Forecasts will budget for these expenses.

Environmental Fees – Permit and environmental reporting fees should be budgeted by each location. The Environmental Dept. will budget for all software maintenance fees associated with the ESC CEM data acquisition systems. The Environmental Department will also budget for all stack and CEM RATA testing including labor, materials and outside test contractors. Questions should be directed to **Brittany Cannato 879-6442.**

EPRI – Business Units should budget for EPRI expenses based on approved programs as well as approved participation in Tailored Collaboration Projects, Co Funding Projects, or Billable Service Agreements (Supplemental Agreements that are in addition to membership selections). Item numbers for EPRI subscriptions will be available from FE Technologies . Subscription payments should be budgeted monthly. Business Units who budget for EPRI should contact **Stephen B. Briggs 825-3870**, for further information.

Fuel – Nuclear: The nuclear fuel expense budget is developed and entered by the Nuclear Fuels group based on generation plans provided by each nuclear unit. Auxiliary boiler and diesel generator fuel is budgeted by each nuclear site and entered by the Nuclear Generation Business Services. Capital nuclear fuel purchases will be budgeted by the Nuclear Fuels group, to appropriate WBS elements.
Fossil: Coal, Oil (light-off and peaking), natural gas, SO2 allowances, NOX allowances, and reagent

requirements will be modeled by the FES Planning & Analysis Group and budgeted by the Fuel Supply Dept., using the plant/unit specific FERC cost centers.

Insurance – Property and liability insurance will be budgeted by Risk Management.

Internal Use of Electricity – The costs of electricity for buildings and power plants owned by FE legal entities within the Competitive Services Unit and Corporate Support Unit, for both generation and non-generation components will be budgeted by **William Shonk (825-5472)** of General Accounting Services in coordination with Customer Service, Retail Tariff Analysis & Forecasting and Facilities Management.

Inter-company Building Rent Revenue/Expense – The inter-company revenue and expense for building rent invoiced between companies will be budgeted by **Richard Snyder (500-6807)** of General Accounting Services and will be based upon building related operation and maintenance costs budgeted by others.

Materials and Equipment – Material costs for direct purchases and stores issues are budgeted directly in the cost center, order or WBS element along with the responsible cost center. An M&S overhead will be applied to stores issues. The Controller's Group will enter the rates into the costing sheets and the system will generate the M&S overheads as part of the budget closing process.

Professional Contractors & Outside Services – Contracted work from professional and outside services vendors should be accounted for using the categories and cost elements established by Business Unit. Please refer to the tables in Chapter 7 for further details.

Revenues – Budgeted revenues must be entered as **negative** numbers.

Sales Tax – Business Units should include sales taxes incurred as part of the purchase price of taxable items in their cost centers.

Medical Surveillance Testing – Occupational Health -The outside vendor costs for employees participating in the FirstEnergy Medical Surveillance Program (Regulatory required) should be budgeted in the individual employee's responsible Cost Center. Each Plant and Operating Company should account for these costs (i.e., regulatory required respirator fitness exams, hearing tests, asbestos and lead physicals, etc.). The Industrial Relations-Health & Safety section will provide specific cost information related to this activity, contact **Timothy Walter 825-1706 or Chuck Fabo 825-5162.**

Drug & Alcohol Testing Program – CDL/DOT, Maritime, Safety Sensitive, Ohio State Project Work, New Hires- The outside vendor costs for employees participating in FirstEnergy's Drug & Alcohol Testing Program (Company and Regulatory required) should be budgeted in the individual employee's responsible Cost Center. Each Plant and Operating Company should account for these costs in 2014. The Industrial Relations-Health & Safety section will provide specific cost information related to this activity, contact **Timothy Walter 825-1706 or Chuck Fabo 825-5162.**

Industrial Hygiene (IH) Assessments – The outside vendor costs associated with OSHA required routine IH monitoring, including associated laboratory analyses and processing costs, should be budgeted in the individual employee's responsible cost center. Routine monitoring (OSHA required) includes periodic assessment of the following hazards: Noise, Asbestos, Inorganic-arsenic, Lead, Personal Protective Equipment, Confined Space Entry, etc. The Industrial Relations–Health & Safety section will continue to support and budget for special, complex or unique IH assessment needs. Specific cost information related to this budgeting activity will be provided by the Industrial Relations-Health & Safety section, contact **Timothy Walter 825-1706 or Martin Duffy 825-3814.**

Satellite Airtime – The infrastructure cost to provide the service will be paid by IT Network Services. The usage is not an IT cost and should, therefore, be budgeted by the business units at these rates:

BTV broadcasts $800 /hour (Bandwidth 3.0Mb/hr)

Severance – Each Executive Council member is contacted by HR to determine the appropriate level of severance to be budgeted. Cost of severance payments, as determined by HR, will be entered into the SAP system by HR/Corp Budgets/Forecasts.

Supply Chain/Inventory Items – Inventory Adjustments - Each plant and Operating Company should budget for its own storeroom's inventory adjustments. Assets No Longer Used or Useful – Obsolete Inventory - Each location should budget for its own obsolete inventory write-offs. With market value of these items being unknown, it is recommended that Business Units not budget for proceeds from obsolete inventory sales. Assets Other Than Inventory - Investment recovery proceeds from the sale of items will be given to the Business Unit that provided the items. We will use the accounting the Business Unit provides.

Training – Business unit cost centers should budget for on-site classes that support company-wide, employee, or department-specific programs. **The Learning and Development Department (L&D) will budget for the New Supervisor/Manager program. However, the business unit cost centers should budget for associated travel and lodging expense.** Questions should be addressed to **Jacqueline Roth 825-7890.**

The Information Technology Dept (IT) will budget for on-site classes that support company-wide software applications. Business unit cost centers should budget for on-site classes that support department-specific software applications.

Training – External – The cost of external training and seminars, as well as the travel and lodging expenses will be budgeted in the cost center requesting the training.

Transportation – Energy Delivery Transportation costs will be manually planned to appropriate cost collectors using the cost element 545099 – Fleet usage manual plan. The responsible cost center used on the SPL is the appropriate Operating Company transportation contra cost center.

COMPANY	CONTRA COST CENTER	DESCRIPTION
Toledo Edison	416001	Transportation Costs Undist-TE-Wstrn Reg
CEI	426001	Transportation Costs Undist-CE-Nrth Reg
Ohio Edison	406001	Transportation Costs Undist-OE-Cntrl Reg
Ohio Edison	406005	Transportation Costs Undist-OE-Sthrn Reg
Ohio Edison	406003	Transportation Costs Undist-OE-Estrn Reg
Penn Power	436001	Transportation Costs Undist-PP-Estrn Reg
Penelec	456001	Transportation Costs Undist-PN-W PA Reg
Met Ed	446001	Transportation Costs Undist-ME-E PA Reg
JCP&L	466003	Transportation Costs Undist-JC-Nrth Reg
JCP&L	466001	Transportation Costs Undist-JC-Cntrl Reg
West Penn Power	492001	Transportation Costs Undistrib- WP01
Mon Power	470201	Transportation Costs Undistrib - MP01
Potomac Edison	483001	Transportation Costs Undistrib - PE10

The Operating Companies must also plan a credit to the contra cost center in the amount planned out to the cost collectors using the same Responsible Cost Center. The contra cost center should be used as the target cost center for these credits.

Vehicle Leases & Licenses –
Vehicle lease payments should be budgeted, using G/L account 570050 for all Operating Leases and 570075 for all Capital Leases, for the following:

- Fleet Services cost center for Operating Company vehicles, (it is no longer necessary to budget by each department in the Operating Company using the vehicle).
- Each fossil generation plant, each nuclear generation plant, environmental, generation technical services.
- Each non-Operating Company or non-plant department using a vehicle. This would include (but is not limited to): IT, Corporate Transportation, Workforce Development, Administrative Services, T&D Technical Services.

Vehicle licenses should be budgeted, using G/L account 650300, for the following:

- Fleet Services cost center for Operating Company vehicles.
- Each fossil generation plant, each nuclear generation plant, environmental, generation technical services.
- Each non-Operating Company or non-plant department using a vehicle. This would include (but is not limited to): IT, Corporate Transportation, Workforce Development, Administrative Services, T&D Technical Services.

All requests for vehicles and/or power operated equipment should be directed to the Fleet Manager (see below) responsible for the area where the vehicle and/or equipment will be assigned. The Fleet Manager will work with Corporate Fleet Services directly to place the order, etc. Any questions related to this matter should be directed to **Lisa Pfeifer 824-5090.**

Company	Fleet Services Manager	Internal Phone	External Phone
CEI	Bryan Komlos	824-5060	216-295-5060
Toledo Edison	Jeff Burgoon	883-5938	419-249-5938
Ohio Edison/Penn Power	Robert Pyles	835-4099	330-436-4099
West Penn Power	Mike Geitner	365-2020	724-743-2020
Penelec	Wally Cunningham	430-8803	814-868-8803
Met Ed	Frank Cummins	500-6573	610-921-6573
Mon Power	Forrest Miller	324-1211	304-284-1211
Potomac Edison	Jasan Hileman	300-5227	301-582-5227
JCP&L	Nick Dello Russo	210-2237	973-989-2237

Personal Computer Hardware Items that require direct funding by the Business Units:

Unique, non-standard PC configurations. IT budgets each year for standard notebook and desktop models and configurations. At the time IT approaches a client group to plan for the retirement / replacement of their existing computers, the client group will need to provide the funds to cover any cost above the standard model cost. Funding by the client will be required for special features such as:

- RAM (memory) above the standard configuration
- Higher CPU speeds or multiple CPU's
- Tower model
- Floppy drive (no longer provided on new PCs)
- Video graphic cards

- Extra network interface cards
- Optical or wireless mice or special trackball configurations
- Ergonometric keyboards
- Larger internal or external storage drives or memory sticks
- Port replicators or docking stations
- Second batteries for notebook PCs
- Glare shields
- DC power converters or adapters
- Monitors for notebooks (If you presently have one with your notebook, when it fails, it will not be replaced without business unit funding.)
- Local printer (all printer requests must be forwarded to **David A. Zeigler** for review).

Process related PCs. IT budgets each year for rollover of **20%** of the office desktop PCs and **33%** of the office notebook PCs. PCs that are not typically used by employees, but rather dedicated to a process are not funded out of the PC capital budget. Funding must be provided either within a capital project when these systems are upgraded, or by the business unit. Examples of process PCs include:

- AFSO and MRMS (TPP)
- EMS Consoles
- GMS Consoles
- HVAC controls
- Plant control systems
- Badge readers
- Field equipment testing or data logging PCs
- Special printer, scanner or plotter interfaces
- Cache PCs (pseudo servers)

Off-cycle (premature) replacement PCs. As mentioned earlier, IT budgets each year for rollover of 20% of the office desktop PCs and 33% of the office notebook PCs. The scheduling of replacements is determined by the local Desktop Support team. Should any department require a notebook PC to be replaced sooner than every 3 years, or a desktop model to be replaced sooner than every 5 years, the client group must fund the complete cost of the replacement.

Off-cycle upgrade of a desktop unit to a notebook unit. If an employee, because of their job responsibilities, requires switching from a desktop PC to a notebook PC, the full cost of the new notebook PC must be borne by the business unit if their desktop is not scheduled to be replaced. The exception to this rule is if the business unit still has un-deployed notebook PCs in its annual replacement allotment, the business unit leadership may elect to redirect a yet-to-be-deployed notebook from its pool to the employee in need, at the sacrifice of another employee within the business unit. That impacted employee would then be given the notebook recipient's existing desktop PC.

On-cycle upgrade of a desktop unit to a notebook unit. If an employee, because of their job responsibilities, requires switching from a desktop PC to a notebook PC, and the timing of this need coincides with our replacement schedule, IT will cover the higher cost of the notebook PC. New or replacement notebooks will require director level review and approval. There must be a valid business case for using a notebook model.

Second PCs. If an employee requires more than one PC to perform their job, the full cost of the additional PCs must be borne by the business unit. This includes instances where a hot-standby PC must be provided for a critical function. The exceptions to this rule are console-based PCs, such as those in plant control rooms or regional dispatch centers where 2-3 PCs and/or monitors are part of the console and required for the operator to perform their work. This second PC will be an asset managed and maintained by IT, following the same standards and practices used for IT-funded PCs.

<u>Moves, Adds, Changes (MACs) of Employee Services and Devices at Company Facilities –</u> For all locations other than Shared Services' workspace in Akron General Office and the Reading General Office - Business Units will be responsible for budgeting for their planned moves, adds and changes described below:

- Non-computer equipment, such as telephone sets, headsets, speakerphones etc.
- Install and terminate voice cabling to workstations.
- Creation of the workstations in the telephone system database.
- Cross-connected and install telephone instruments.
- Move telephones to existing or new jack locations.
- Install, terminate, and test data cabling to the workstations.
- Activate data jacks by patching through to data switches.
- Install, terminate, and test inside fiber optic cabling.
- Install and terminate coax cabling for applications such as Satellite for IDL.

This does not include maintenance or repair responsibilities for these items. Normally the moves, adds, and changes are considered an O&M cost, unless they are associated with a major project.

The usual way to schedule moves, adds and changes is to contact your local facilities management team. This team will contact IT Field Operations to arrange for the approved vendors to make your requested changes. MACs that do not require Facilities involvement can be requested by calling the IT Service Desk. Please adjust your 2014 budget to include your facilities plan.

CHAPTER 4: CAPITAL MANAGEMENT PROCESS

FE's capital investments are integral in helping the company achieve operational excellence and financial success. The capital expenditures, are necessary to ensure the reliable generation and distribution of electricity, and compliance with regulatory requirements.

The Capital Planning & Management Process is a formalized process that provides the platform for capital discussions and allocation decisions at all levels of the organization. The process helps senior management to effectively understand competing uses for FE's cash, funding requirements for capital investments, and to allocate capital dollars across various business units (ED, FENOC, Fossil, Corporate). Ref. Capital Planning & Management Corporate Policy CP-TPR-6101 and FE 5-year Capital Portfolio Development and Capital Management Procedure (FirstPlace Portal/About FirstEnergy/Policies and Practices/Overview/Capital Management Procedure.pdf)

Capital Categories:

Mandatory - Non-discretionary investment required by law, regulatory order, or duty to serve customers (e.g. new business). Other required investment to meet externally driven regulatory commitment.

Maintain - Discretionary investment to support and sustain existing infrastructure at existing performance levels. Specific operational performance and financial tracking support these projects (e.g. SAIDI, CAIDI, EFOR).

Improve - Discretionary investment to improve existing infrastructure or performnace levels beyond existing business plan key performance metric commitments. Improvement in specific operational performance and financial benchmark targets support these projects (e.g. SAIDI, EFOR, ROI).

Value - Discretionary, non-recurring investment for a defined initiative which improves or expands existing infrastructure or creates new business opportunities and drives improved economic value.

Capital questions contact:

Business Area	Business Area Contact	Capital Support
Corporate Services - IT	Debbie Luttner (350.6934)	Megan Gallagher (825.5821) Scott McBride (825.4888)
	Dave McGaha (850.2167)	
Corporate Services - Facilities	Bob Grosjean (825.6393)	
	Tom Yanks (825. 5926)	
Corporate Services - Other	Business Area Management	
FE Utilities/Transmission	Mark Myers (825.7961)	
	Marcus Geise (825.2542)	
Fossil Generation	Joe Walko (350.5722)	
	Denise Bracken (850.7237)	
FENOC	Jay Morris (879.5425)	
	Don Jacobson (879.7605)	
FES - Other	Ollie Pannell (850.6868)	
	Brandon Fedor (850.7226)	

Capital Projects – Only budget capital projects to the level of spending identified in Executive Council guidance

Work Breakdown Structures (WBS) - Labor is budgeted through Activity Input Planning using transaction CJR2. Loaded labor costs, which include overheads, are moved from the employee or sending cost center to a WBS element by planning productive hours by activity type. Instructions for Activity Input Planning are located in Chapter 2 - Labor. All 'Other than Labor' costs are input into the SPL using transaction GP12N and must include the cost element and the appropriate responsible cost center. Instructions for input are found in Chapter 3 – OTL.

If new WBSs are created, all master data fields (i.e., costing sheets, project type, interest profiles, settlement rules, etc.) must be entered into SAP. **(See Key Contact appendix, page 26, for names to set up the WBS Master Data.) In all cases, it is critical that the WBS and WBS element start and finish dates be accurate and the WBS should be established at the Company which will own the assets. Departments which complete work for other Companies should cross charge the other Company WBS. Planning must never be entered in months beyond the finish date.** These dates are used by Property Accounting Services to compute and input AFUDC and depreciation and in reporting, including rate cases. All WBSs with settlement rules to asset accounts (CWIP, RWIP & OWIP) require an AFUDC element regardless if the project would qualify for AFUDC.

The status of WBSs must be TECO (Technically Complete), when the project is ready for service. The TECO date is passed to PowerPlant and the project is placed in-service. If a project is suspended or ceases construction the WBS elements should be locked and the status of the project is changed to "suspended" in PowerPlant. This will shut off the AFUDC calculation. If a project is cancelled existing charges should be transferred to expense, the AFUDC should be reversed and once the charges have been removed from the WBS, the WBS should be 'business closed". **It is important to update the status to TECO on a timely basis since it directly reflects the calculation of AFUDC and the beginning of depreciation in PowerPlant.**

Construction Indirects (Supervisory, Engineering, Administrative and General Overheads) – Capital costs should be direct charged to the related WBS whenever possible. However, in those cases where certain costs have a proven relationship to construction, an assessment or allocation will be made from predefined cost centers to Operating Company construction indirect cost centers (Supervision, Engineering, and A&G). An example of this would be supervision of an engineering group that supports capital projects overall. A portion of those supervision costs will be allocated to capital using the prescribed process. Rates will be calculated by General Accounting Services for each Operating Company and overhead category and will be applied on the labor and contractor portion of the budgeted WBS elements.

PowerPlant Property Unit Catalog – The PowerPlant Property Unit Catalog should be used to determine what items or activities are capital. Assistance in using the Property Unit Catalog or questionable items should be directed to **Tim Clyde (825-5863)**, Property Accounting Services, prior to inclusion of an item in the budget as capital.

Small Tools and Equipment - Only small tools and equipment greater than $1,000 should be capitalized.

Corporate Facilities will budget for all facility-related Mandatory and Maintain capital project work across FirstEnergy. Each Business Unit will budget for any Value Added or Improve facility related capital work. If there are questions on definition, please refer to the Capital Definitions section.

Vehicles/Power Operated Equipment
When acquiring the equipment identified below, the acquisition should be coordinated with the Corporate Fleet Services Department. The Corporate Fleet Services Department will determine with Treasury whether to purchase or lease the equipment. If the decision is to purchase the equipment, Corporate Fleet Services will purchase the equipment and charge the appropriate capital WBS. The equipment will also be given a vehicle number and tracked in the M5 Fleet System.

All requests for vehicles and/or power operated equipment should be directed to the Fleet Manager (see below) responsible for the area where the vehicle and/or equipment will be assigned. The Fleet Manager will work with Corporate Fleet Services directly to place the order, etc. Any questions related to this matter should be directed to **Lisa Pfeifer 824-4090.**

Company	Fleet Services Manager	Internal Phone	External Phone
CEI	Bryan Komlos	824-5060	216-295-5060
Toledo Edison	Jeff Burgoon	883-5938	419-249-5938
Ohio Edison/Penn Power	Robert Pyles	835-4099	330-436-4099
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Penelec	Wally Cunningham	430-8803	814-868-8803
Met Ed	Frank Cummins	500-6573	610-921-6573
Mon Power	Forrest Miller	324-1211	304-284-1211
Potomac Edison	Jasan Hileman	300-5227	301-582-5227
JCP&L	Nick Dello Russo	210-2237	973-989-2237

Asset Class	Vehicle Type
1	Light Duty - primarily downsize pickups, mini vans, passenger cars & units impacted by EPAct
2	Medium Duty - includes full size pickups, vans, substation vehicles, small stake body trucks, etc
3	Heavy Duty - includes heavy trucks other than aerial units, digger derricks or crane trucks
4	Aerial Trucks - includes all manlift capabilities regardless of size
5	Digger Derrick Trucks - includes all digger derricks
6	Crane Trucks - includes all trucks with cranes mounted on them and licensed. Off road cranes are included in construction equipment
7	Trailers - includes all trailers regardless of size
8	Construction Equipment - includes backhoes, loaders, excavators, off-road cranes, dozers, etc
9	Forklifts, Mowers, Misc - includes forklifts, riding sweepers, scrubbers, snow removal equipment, mowers, ATV's & other.

Office Furniture – The Real Estate and Facilities Department manages and budgets all capital expenditures for furniture as well as maintains an inventory of existing furniture items. The Facilities Section has developed the Workspace Guidelines Policy and receives substantial discounted pricing on all furniture used by the Company.

All requests for furniture should be directed to **Kathy Tatman, Supervisor, Asset Planning** through an e-mail notification. Please base your request on budgeted new hire positions and/or replacement requirements for worn, damaged or obsolete furniture. Any purchases of furniture made outside of this arrangement will not be approved.

Software Costs - The following guidelines should be used for capitalizing computer software costs:

New Computer Software Costs:

- designed as a complete system
- has a life greater than 1 year
- capitalized cost is greater than **$5,000**

Preliminary study costs, data conversions, and training are expensed when installing computer software.

Upgrades and Enhancements of Existing Software:

Upgrades and enhancements of existing software are expensed unless additional functionality is added and the cost is greater than **$5,000** and is a significant upgrade or enhancement.

Questions concerning capitalization of Computer Software items should be discussed with **Tim Clyde (825-5863)**, Property Accounting Services, prior to inclusion in the budget.

Generation Employee Training Costs – All employee training costs should be expensed, **except for Yards Creek.**

IT Projects – Activity allocate appropriate labor charges to IT managed projects that require Business Unit support. *All IT projects created under SC00 WBSs that are for the benefit of other Companies should have settlement rules that settle these costs to other company WBSs*. IT Department should coordinate these projects with the appropriate Business Services group.

Depreciation – The computation and application of depreciation will be the responsibility of Property Accounting Services.

Major Retirements of Plant – For retirements of plant, in which the estimated original cost exceeds $5 million, the following information is required: the month the item is being retired, the estimated original cost, and a short description of the item being retired. For all other retirements, a historical average will be used by Property Accounting Services. Retirements related to replacement WBSs should be made at the time the WBS is placed in service.

Generation Cost of Removal and Salvage – The budgeting of cost of removal and salvage will be performed by Generation. Generation cost of removal is expensed, **except for Yards Creek.**

Energy Delivery (Distribution and Transmission) Cost of Removal and Salvage – The budgeting of distribution and transmission cost of removal and salvage will be performed by Energy Delivery. For Met-Ed, Penelec, and JCP&L, the cost of removal and salvage will be expensed as a component of the depreciation expense in accordance with the current rate making. The planned cost of removal and salvage will settle to Account 403, Depreciation Expense.

Note: Cost Type is a required input field when entering the plan into the SPL (SAP Transaction GP12N). Changing the settlement rule on the WBS master data does not change the Cost Type in the plan. It is important that the WBS master data and the Cost Type are reviewed for accuracy

and consistency prior to input (Cost Type 1 is for Capital, 2 is for O&M and all other P&L items including Depreciation account 403, and 3 is for Balance Sheets accounts not considered capital).

CHAPTER 5: INTERCOMPANY TRANSACTIONS

Unless given approval by Corporate Budgets and Forecasts, General Accounting Services working with Corporate Budgets and Forecasts, will enter the budget estimates for all inter-company expenses and revenues. Corporate Budgets and Forecasts **(Mike Kreighbaum 825-2556)** will coordinate this effort. Unless approved for entry by the Business Units, inter-company expenses or revenues must be forwarded to General Accounting Services or Corporate Budgets and Forecasts for entry into the system. The required information to be forwarded includes:

- Inter-company G/L Accounts (Assoc. Company wording is typically included in the account description)
- Cost Centers
- Monthly Budget Amounts
- Description of transaction and the Cost Centers and G/L Accounts used for the offsetting revenues or expenses (if known)

Some examples of inter-company transactions include:

- Purchased Power and Revenues including RFP and POLR sales
- Interest Income or Expense from Associated Companies
- Leases including ATSI ground lease
- Internal Use of Company Electricity
- Billings between subsidiaries (Bayshore Power, FE Properties, etc.)

CHAPTER 6: FIRSTENERGY SERVICE COMPANY

Service Company Cost Centers – Budgeting Guidelines:

Direct Charging
When preparing your budget and incurring actual expenditures, it is important to consider who the beneficiary of your services is. Direct charging of time and expenses to the entity for which the services are being rendered is the preferred approach, where possible. To the extent that costs can be readily identified and associated with a specific transaction, the charging of those costs should be directed to the company(ies) receiving the goods or services, even when there is more than one receiving company.

Indirect Charging
Indirect charging through the Service Company assessment process supplements the direct charging of costs. Assessments are used to allocate the costs that were not direct charged from a cost center. Frequently, costs can not be direct charged because the recipient cannot be readily identified, or excessive administrative expense would result. Indirect charging employs the use of one of FirstEnergy's approved assessment methods. An approved assessment method is assigned to each Service Company cost center. The assessment methodology and the targeted legal entities for the Service Company cost centers can be provided by General Accounting upon request.

Service Company Assessments
Any desired change to organizational structure or revisions to the methodology used to allocate expenses from a Service Company cost center to the other legal entities must be reviewed and approved by **Joseph Mulpas, Assistant Controller (825-4049)**, prior to the change being implemented. This review process in necessary to insure that inter-company service agreements remain current and valid and that all regulatory requirements are being satisfied.

CHAPTER 7: BUDGETING REFERENCE MATERIAL

Primary Distribution Keys Used for Monthly Spreads

NOTE: Distribution Keys **do not** perform the wage escalation of your planned labor dollars. You need to plan your total gross payroll. The distribution keys are used to allocate your planned gross payroll to the appropriate months in accordance with that year's payroll calendar and wage escalation assumptions.

Please contact Mke Kreighbaum (825-2556) to request set up of new distribution keys.

2014	Distribution Key	Description
	P14S	NonBarg Bi-Weekly Pay 3.00% WRI Sep 2014
	P14B	Payroll BiWeekly 2014 3% March
	P14W	Payroll Weekly 2014 3.25% March
	PBM4	Barg Weekly Pay 2014 March 3% Inc
	PMH4	Barg Weekly Pay 2014 March 2.5% Inc
	PBW4	2014 Bi Wkly with 3.75% WRI Mar 2014
	PMY4	2014 Barg/Wkly Pay - with 3.00% WRI MAY
	P14M	Payroll BiWeekly 2014 3% May
	PMB4	2014 Bi-Weekly PR with 2.0% WRI MAY
	PJL4	2014 Barg/Wkly Pay - with 3.00% WRI JUL
	PJY4	2014 Barg/Wkly Pay - with 2.75% WRI JUL
	PAU4	2014 Barg/Wkly Pay - with 3% WRI AUG
	POC4	2014 Barg/Weekly Pay - with 3% WRI OCT
	PNV4	2014 Barg/Weekly Pay - with 3% WRI NOV
	PNO4	2014 Barg/Weekly Pay - with 2.5% WRI NOV

Other Monthly / Quarterly Distributions

Distribution Key	Description
1	Equal Distribution January - December
QMO	Quarterly - Last Month of Quarter - Mar, Jun, Sep, Dec
QTRM	Quarterly - Middle Month of Quarter - Feb, May, Aug, Nov
H1SP	First Half of Year - spreads evenly over Jan - Jun
H2SP	Second Half of Year - spreads evenly over Jul - Dec
Q1SP	First Quarter Distribution - Spread evenly over Jan - Mar
Q2SP	Second Quarter Distribution - Spread evenly over Apr - Jun
Q3SP	Third Quarter Distribution - Spread evenly over Jul - Sep
Q4SP	Fourth Quarter Distribution - Spread evenly over Oct - Dec
JAN	January Only
FEB	February Only
MAR	March Only
APR	April Only
MAY	May Only
JUN	June Only
JUL	July Only
AUG	August Only
SEP	September Only
OCT	October Only
NOV	November Only
DEC	December Only

Payroll Accounting Periods

PAYROLL ACCOUNTING PERIODS - YEAR 2014

BI-WEEKLY

Acctg Month	End Date			Posting		
	Sat - Fri	Sun - Sat	Mon - Sun	Date	Weeks	Hours
January	01/24/2014	01/25/2014	01/26/2014	01/31/2014	6	240
February	02/21/2014	02/22/2014	02/23/2014	02/28/2014	4	160
March	03/21/2014	03/22/2014	03/23/2014	03/28/2014	4	160
April	04/18/2014	04/19/2014	04/20/2014	04/25/2014	4	160
May	05/16/2014	05/17/2014	05/18/2014	05/23/2014	4	160
June	06/13/2014	06/14/2014	06/15/2014	06/20/2014	4	160
July	07/11/2014	07/12/2014	07/13/2014	07/18/2014	4	160
August	08/22/2014	08/23/2014	08/24/2014	08/29/2014	6	240
September	09/19/2014	09/20/2014	09/21/2014	09/26/2014	4	160
October	10/17/2014	10/18/2014	10/19/2014	10/24/2014	4	160
November	11/14/2014	11/15/2014	11/16/2014	11/21/2014	4	160
December	12/12/2014	12/13/2014	12/14/2014	12/19/2014	4	160
					52	2080

WEEKLY

Acctg Month	End Date			Posting		
	Sat - Fri	Sun - Sat	Mon - Sun	Date	Weeks	Hours
January	01/24/2014	01/25/2014	01/26/2014	01/31/2014	5	200
February	02/21/2014	02/22/2014	02/23/2014	02/28/2014	4	160
March	03/21/2014	03/22/2014	03/23/2014	03/28/2014	4	160
April	04/18/2014	04/19/2014	04/20/2014	04/25/2014	4	160
May	05/23/2014	05/24/2014	05/25/2014	05/30/2014	5	200
June	06/20/2014	06/21/2014	06/22/2014	06/27/2014	4	160
July	07/18/2014	07/19/2014	07/20/2014	07/25/2014	4	160
August	08/22/2014	08/23/2014	08/24/2014	08/29/2014	5	200
September	09/19/2014	09/20/2014	09/21/2014	09/26/2014	4	160
October	10/24/2014	10/25/2014	10/26/2014	10/31/2014	5	200
November	11/21/2014	11/22/2014	11/23/2014	11/28/2014	4	160
December	12/19/2014	12/20/2014	12/21/2014	12/26/2014	4	160
					52	2080

Budget/Forecasting Transaction Overview & Template Uploads

BUDGET/FORECASTING TRANSACTION OVERVIEW

		Activity Input Planning (Hours)				
	Gross Payroll	Cost Center	Internal Orders	WBS Elements	OTL - Spec Ledger	Head Count
Planner Profile Transaction	KP04	KP04	KP04	KP04	GLPLSET	KP04
Profile	FE-CO01	FE-CO01	FE-CO01	TD-PS01 GEN-FRMF GEN-FRMN	ZZSPL902	FE-CO01
Input Transaction	KP06	KP06	KPF6	CJR2	GP12N	KP46
Layout	CC - Prime	CC - Act	OR - Act	WBS - Act	ZZSPL90	FE - SKF
4 Year Layout	CC - Prime - Y4	CC - Act - Y4	OR - Act - Y4	WBS - Act - Y4	ZZSPL90 - Y4	SKF - Y4

Notes/Versions:
Budget Input - Version 11
Forecast Input - Version 20

BUDGET TRANSACTION OVERVIEW WITH TEMPLATE UPLOADS

		Activity Input Planning (Hours)				
	Gross Payroll	Cost Center	Internal Orders	WBS Elements	OTL - Spec Ledger	Head Count
Planner Profile Transaction	KP04	KP04	KP04	KP04	GLPLSET	KP04
Profile	FE-CO01	FE-CO02	FE-CO02	TD-PS02 GEN-FRMF GEN-FRMN	ZZSPL902	FE-CO01
Input Transaction	KP06	KP06	KPF6	CJR2	GLPLUP	KP46
Template Upload	Extras > Excel Plan > Upload	Extras > Excel Plan > Upload	Extras > Excel Plan > Upload	Extras > Excel Plan > Upload		Extras > Excel Plan > Upload

Select path of text file, file description, and American decimal notation.

File Descriptions:	One year Input	Four year Input
Gross Payroll:	01_1P1_FE-CO02_002CC-PRIME-EXC	01_1P1_FE-CO02_003CC-PRIME-Y4
Cost Center (Hours):	01_1P1_FE-CO02_001CC-ACT-EXCEL	01_1P1_FE-CO02_001CC-ACT-Y4
Internal Order (Hours):	01_1P4_FE-CO02_001OR-ACT-EXCEL	01_1P4_FE-CO02_001OR-ACT-Y4
WBS Element (Hours):	01_1P7_TD-PS02_001FE-WBS-ACT2	01_1P7_TD-PS02_001WBS-ACT-Y4
SPL/Other than Labor:	07_ZZSPL90A_ZZSPL90_001ZZSPL90EXCEL	07_ZZSPL90A_ZZSPL90_003ZZSPL90-Y4
Headcount:	01_1P3_FE-CO02_001EXCEL-SKFS	01_1P3_FE-CO02_002SKF-Y4

Key Terms & Concepts

Activity Price
The price calculated for an activity type – used for charging labor hours and transportation usage to cost collectors.

Allocations
Used to: assess shared services costs; move charges to correct legal entity; and/or assign to capital where appropriate.

Assessments
Transactions that allocate costs from Cost Centers to receiver cost objects.

Cost Allocation
Distribution of costs from one collector to another to reflect actual usage or predefined rates.

Costing Sheet
Defines an overhead calculation. Contains the percentages to be applied to the base amount and the collector to be credited.

CREWS (Customer Request Work Scheduling)
Used to estimate and schedule Transmission and Distribution projects.

Customer Care Services (CCS)
The SAP R/3 software module for utility customer information.

EC-CS (Enterprise Controlling – Consolidation System)
The consolidation module of SAP R/3 used for legal consolidation reports.

Financial Accounting Module (FI)
SAP R/3's grouping of financial data required for external reporting purpose such as balance sheet, P&L statements, cash flows, and retained earnings.

Overhead Rate
A surcharge, expressed as a percentage, used to spread indirect costs over a defined base.

Project System (PS) SAP R/3 Module
Module is used to manage large projects. Accounting data used to manage WBS Elements are also located in this module.

Profit Center
Organizational unit that reflects a management-oriented structure for the purpose of internal control and reporting.

Profit Center Accounting (PCA)
A module of SAP used to manage the business by segregating costs and revenues by business units. Measures profitability by profit center or high-level business unit.

Settlement
The SAP process of allocating costs from temporary cost collectors such as orders or WBSs to other cost collectors such as FERC cost centers.

Settlement Rule
Set of instructions that define distribution of costs incurred on a temporary cost object such as an order or WBS.

Special Purpose Ledger (SPL)
A stand-alone ledger within SAP that maintains detail without creating additional master data. Used by FE to track costs by Responsible Cost Center.

Financial Accounting Module (FI)
SAP R/3's grouping of financial data required for external reporting purpose such as balance sheet, P&L statements, cash flows, and retained earnings.

Key Contacts

By Department:

Area	Key Contact	Responsibility
Corporate Budgets and Forecasts	• Gina Caskey • Mike Kreighbaum • Carrie Wokaty • Mark Dudley	• SAP specific budget system preparations • Activity prices • Communicating the dates and times for budget input • Oversight and management of the annual budgeting and forecast processes • Tracking budget status and ensuring completion of key budget mid-point deliverables • Ad-hoc budget related reporting • PCA
Business Services and Corporate Business Planning	• Gina Caskey • Mark Dudley • Carrie Wokaty	• Corporate Shared Services – budget and forecast coordination and support • HR Benefits and Special Item budgets and forecasts
Capital Management	• Megan Gallagher • Scott McBride	• Capital Management Processes
Controllers Department	• Denis Dorward • Mike Strozak • Diane McVey • Rich Snyder	• Processing/Closing of SAP Plan • Develop and input Costing sheets (overheads) • System Maintenance – Versions, SPL, CO • Accounting Issues
Business Planning & Strategy	• Paul Mallue	• Running of production cost modeling
Competitive Retail Group	• Trevor Fernandez	• Budget and forecasting of competitive retail sales, load & revenue
Rates	• Brad Eberts • Bill Moll/Rich Faschan	• Development of the Load, MWH Sales, and Wires Forecast • Forecasting of regulated revenue for budgeting
Supply Chain	• David Zeigler	• Personal Printer requests

For SAP Master Data questions or to set up new Master Data for the 2014 Budget:

Master Data		
Contact:		
➢ Cost Centers – Denis Dorward 500-8678; Michael Strozak 500-6554		
➢ Internal Orders – Denis Dorward 500-8678; Michael Strozak 500-6554		
➢ Cost Elements – Will Blair 825-5866		
➢ WBS Elements – By Business Unit		
Energy Delivery Operating companies:		
The Illuminating Co	Gregory Werner	824-8783
Ohio Edison/Penn Power	Eric Weaver	835-4021
Toledo Edison	Ann Toth	883-5016
Jersey Central	Sue Gabel	200-8673
Met Ed	Pete Dragoich	500-6892
Penelec	Guy Costa	430-8874
Mon Power	Sara Cetorelli	333-7320
Potomac Edison	Clarence Haden	300-5218
West Penn	Marianne Sobota	350-5847
ED Finance	Eric Herrmann	825-5444
Fossil Generation Group	Katie Pinkus Denise Bracken	850-6820 850-7237
Nuclear (FENOC)	Katie Pinkus Desiree Etchell	850-6820 850-6877
Information Technology, Security	Mark Dudley	825-1683
Facilities	Tim Goughnour	500-6974
All Other Groups	Mike Czubinski	825-5646

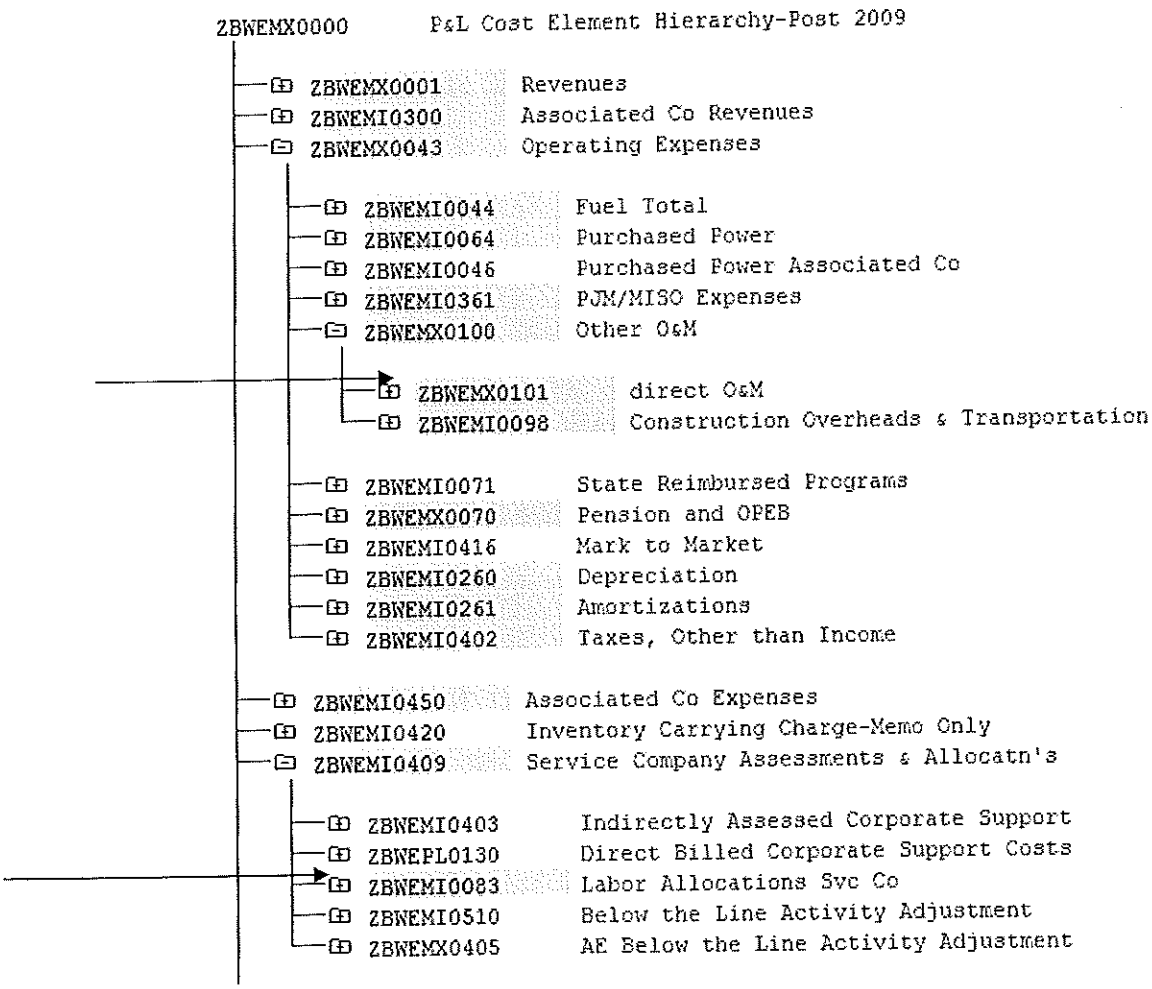
Key Contacts

For Questions by Topic or Business Unit:

Questions or Issue Topic	Name	Phone Number
Inter-company Billings	Mike Kreighbaum	825-2556
General SAP	Mike Kreighbaum	825-2556
	Mark Dudley	825-1683
	Carrie Wokaty	825-6005
	Marie Rote	825-3854
Profit Center Accounting	Mike Kreighbaum	825-2556
	Carrie Wokaty	825-6005
FE Solutions	Paul Mallue	850-7254
	Andy JayJack	850-7332
	Katie Pinkus	850-6820
Fossil Generation Group	Denise Bracken	850-7237
	Katie Pinkus	850-6820
Nuclear (FENOC)	Desiree Etchell	850-6877
Records Management/Corporate/Real Estate	Marie Rote	825-3854
Energy Delivery Business		
The Illuminating Co	Gregory Werner	824-8783
Ohio Edison/Penn Power	Eric Weaver	835-4021
Toledo Edison	Ann Toth	883-5016
Jersey Central	Sue Gabel	200-8673
Met Ed	Pete Dragoich	500-6892
Penelec	Guy Costa	430-8874
Mon Power	Sara Cetorelli	333-7320
Potomac Edison	Clarence Haden	300-5218
West Penn	Marianne Sobota	350-5847
Utility Support	Eugene DeChellis	825-7969
Customer Service & EE (Energy Efficiency)	Rob Wemhoff	825-7981
Finance	Marie Rote	825-3854
General Counsel (Legal, Claims, Communications, Corp. Affairs, Government Affairs)	Marie Rote	825-3854
Human Resources	Marie Rote	825-3854
Information Technology	Mark Dudley	825-1683
Supply Chain	Mark Dudley	825-1683
Corporate Security, Flight Operations	Mark Dudley	825-1683

Responsible Direct Cost O&M Reporting – Cost Elements Included

Use SAP Transaction KAH3 to view the Cost Element hierarchy shown below. Cost Element Groups **ZBWEMX0101 and ZBWEMI0083** are the two groups included in direct cost O&M reporting.



Corporate Shared Services – Professional & Contractor Services - Guidelines

GL	GL Short Name	GL Long Name	General Description	CSS Description/Examples
550100	OutContrctProNonLeg	Outside Services/Contractors - Professional Non-Legal	Service Contracts for unique skill-sets that we don't do in-house.	Security Equipment Installation & Investigations, Software Application Consulting/Training, Lobbying Firms, Ethnics Vendors, Expert Legal Witness, and Facility "White" Collar - Engineering, Electrical, etc.
550200	OutContractProLegal	Outside Services/Contractors - Professional Legal	Legal Fees/Legal Expenses	Law Firms Only
550300	OutContract-Other	Outside Services/Contractors - Other	Facilities	Security Guards, Annual Shareholders Meeting, Facility "Blue Collar" Contractors - Janitorial, Landscaping, Snow removal, etc.
550310	OutContractTreeTrim	Outside Services/Contractors - Tree Trim	Major Storm Deferrals	Major Storm Deferrals
550320	OutContractTempAgnc	Time and Material Contractor	Temp hires not managed by a staff service provider.	Guidant, Jet Professionals
550500	ONSITECONSLT/STFFAUG	On-Site Consultants/Staff Augmentation	Managed Service Provider - used to manage co-employment issues	Guidant, Garrettcom Utility Networks
550503	Envrmnt Wrk & Comp	Environmental Work and Compliance	Environmental	Warrenton River Terminal - Environmental

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Fossil – Professional & Contractor Services Guidelines (pgs. 30-31)

GL	GL Short Name	GL Long Name	General Description	Fossil Description/Examples
550100	OutContrctProNonLeg	Outside Services/Contractors - Professional Non-Legal	Labor outside of the plants possessing skills/knowledge that the plant does not have.	Examples include: NDE testing, Divers, Hydrochem (hydro blasting), Training Vendors (providing training on and off site), Guest Speakers, Inspection Services, Lab testing/services, Calibration, Non-repair/non-refurbishment of equipment, Welding Inspectors (x-ray team), Screening Systems International, David C Kissig Enterprises Inc., Turbine Services Incorporated, Structural Integrity Associates, Janx, Surveying, Schedulers, Ardmore, Gas line maintenance.
550105	OutsideSrvsContFees	Outside Srvs/Contractors - Profess Conting	Contingency Fees (jefferson wells for example)	Contingency and incentive fees paid to vendors.
550200	OutContractProLegal	Outside Services/Contractors - Professional Legal	Legal Fees/Legal Expenses	FERC relicensing (primarily used by CT/Hydro plants)
550210	OutContractEngineer	Outside Services/Contractors - Engineering	Contractors asked to provide engineering analysis/studies, project support, or technical development that cannot be completed with in-house engineering staff.	Examples include: Monitoring wells, Marland, RE Warner Consultants helping with outages, GE Energy, Kleinschmidt, Alstom, Siemens, Middough, Door maintenance (CT/Hydro).
550300	OutContract-Other	Outside Services/Contractors - Other	Facilities related work	Examples include: Scrap Removal, Janitorial work, Lawn care, Snow removal, Garbage and Sewage removal, HVAC/ Non-Plant Equipment, Sirens maintenance, Building and structures maintenance, General Pest Control, Elevator repairs, Grounds and roads maintenance, Auto Repair, Laundry Services, Fence Repairs, US Coast Guard, Fire Inspections, Vegetation Management.

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GL	GL Short Name	GL Long Name	General Description	Fossil Description/Examples
550305	OutContract-ProjMgmt	Outside Services/Contractors - Project Mgmt	Consultants providing project management services such as costing reports.	Examples include JR Johnson, Sargent and Lundy.
550335	OutContrRepairRefurb	Outside Services/Contractors - Repair/Refurbishment /Overhaul of Plant Equipment	Off-site labor repairing/refurbishing/replacing plant production equipment.	Examples include: Repair/refurbish valves, motors, circuit boards, etc.; CMT for Motor repairs, Cleveland Valve & Gauge for valves, Columbus Equipment Company, City Machine Technologies Inc., Monarch Electric Service Company, 3-D Service LTD.
550500	ONSITECONSLT/ STFFAUG	On-Site Consultants/Staff Augmentation	Managed Service Provider - used to manage co-employment issues	Example: Guidant
550501	PRIMMNT CONTRCRAFT	Primary Maintenance Contractor - Craft	On-site craft labor	Examples include: Enerfab, outage work/support, GMAs for bringing in Boilermakers, Insulators, Electrical Contractors, Mechanical Contractors, Patent Construction Systems, Enerfab, Burnham Industrial Contractors, McCarl's Incorporated, ERB Electric Company, Crane Inspections.
550503	Envrmnt Wrk & Comp	Environmental Work and Compliance	Contractors working on Environmental projects or performing work in support of Environmental Compliance.	Examples include: any fees, Consulting services, Test monitors, Replace monitors/analyzers, Ash site maintenance, Cleaning spills, air/water waste, Performing lab work.
550513	OnSiteContractedLbr	On-Site Contractor Labor	Labor outside of the plants providing "turn-key solutions".	Examples include: Fluor, Stein (preventative maintenance).

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Fossil - Project Construction – Professional & Contractor Services Guidelines

GL	GL Short Name	GL Long Name	General Description	Fossil - Project Construction Description/Examples
550100	OutContrctProNonLeg	Outside Services/Contractors - Professional Non-Legal	Labor outside of FirstEnergy possessing specialized skills/knowledge that we do not have in-house.	Examples include: Print Services, Nurses, Investigation Services, Background Checks/Investigations, Training, Inspection Services.
550105	OutsideSrvsContFees	Outside Srvs/Contractors - Profess Conting	Incentive fees	Examples include: Incentive arrangements, Contractor Shared Savings (for example B&W), Contractor Bonuses and Incentives.
550210	OutContractEngineer	Outside Services/Contractors - Engineering	Contractors asked to provide engineering analysis/studies, project support, or technical development that cannot be completed with in-house engineering staff.	Examples include: Conceptual Designs, Detailed Design Mods, Eng. Studies, Non-Mod, Calculations, Evaluations.
550300	OutContract-Other	Outside Services/Contractors - Other	Facilities related work	Facilities related work such as: Scrap Removal, Janitorial work, Lawn care, Snow removal, Garbage and Sewage removal, HVAC/ Non-Plant Equipment, Sirens maintenance, Building and structures maintenance, General Pest Control, Elevator repairs, Grounds and roads maintenance, Auto Repair, Laundry Services, Fence Repairs, US Coast Guard, Fire Inspections, Vegetation Management.
550305	OutContract-ProjMgmt	Outside Services/Contractors - Project Mgmt	Consultants providing project management services such as costing reports.	Examples include JR Johnson, Sargent and Lundy.
550501	PRIMMNT CONTRCRAFT	Primary Maintenance Contractor - Craft	On-site craft labor	Examples include: Enerfab, GMAs for bringing in Boilermakers, Insulators, Electrical Contractors, Mechanical Contractors.
550513	OnSiteContractedLbr	On-Site Contractor Labor	Fixed price, milestone payment, or other "turn key" type purchase agreement.	Examples include: OEM contracts (B&W), EPC contracts (Bechtel), Patent, ERB, contractors for excavating, painting, etc.

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Nuclear – Professional & Contractor Services Guidelines (pgs. 33-34)

GL	GL Short Name	GL Long Name	General Description	FENOC Description/Examples
550100	OutContrctProNonLeg	Outside Services/Contractors - Professional Non-Legal	Service Contracts for Unique skill sets that we don't do in-house	Divers, Vendor Reps, Training Vendors (providing training on and off site), Guest Speakers, Inspection Services, Vendor Source Inspections, Refueling Services, Chemistry Services, RP Services (excluding on-site support), Laundry Services, Management requested contractors/facilitators, Lab testing, Calibration of M&TE, Software customization (firm price), CNRB Members, Investigation Support, TLD Contracts, Supplier List Updates, ANI Support, Corrective Action Program Support, Print Services (Kinkos), Bulk Gas Delivery, Demurrage. Refer to cost element 550513 to ensure correct placement of vendor.
550210	OutContractEngineer	Outside Services/Contractors - Engineering	Engineering Expenses	Engineering support occurring predominantly offsite, Conceptual Design, Detailed Design Mods/ECR, Eng. Studies, Non-Mod, Calculations, Evaluations. Refer to cost element 550513 to ensure correct placement of vendor.
550300	OutContract-Other	Outside Services/Contractors - Other	Other	Lawn care and Snow removal, Garbage and Sewage removal, HVAC/ Non-Plant Equipment, Sirens (Maintenance), Building, Structures, Beta Security, Security Range Maintenance, General Pest Control. Refer to cost element 550513 to ensure correct placement of vendor.
550325	OutContractRadwstDsp	Outside Services/Contractors - Radwaste	FENOC specific	Transportation, Burial, Compacting, Processing and Analysis/Characterization of radwaste. Refer to cost element 550513 to ensure correct placement of resource.
550335	OutContrRepairRefurb	Outside Services/Contractors - Repair/Refurbishment /Overhaul of Plant Equipment	Self explanatory - see FENOC Description	Repair/refurbish valves, motors, circuit boards, etc. Security Repairs (Target Systems, Scope, NVG units), Beta test equipment. Refer to cost element 550513 to ensure correct placement of vendor.

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GL	GL Short Name	GL Long Name	General Description	FENOC Description/Examples
550500	ONSITECONSLT/ STFFAUG	On-Site Consultants/Staff Augmentation	Managed Service Provider - used to manage co-employment issues	Guidant
550501	PRIMMNT CONTRCRAFT	Primary Maintenance Contractor - Craft	Interfab/Day Zimmerman/etc	NPS contracted labor, site manager, administrative personnel.
550502	TIME&MATCONTR	Time and Material Contractor	Primary Security Contractor	Subcontracted outside security for Beaver Valley (Burns and Securitas).
550513	OnSiteContractedLbr	On-Site Contractor Labor	Goes back into capital allocation process for FENOC.	Contracted workers that are on site for a **continuous** period of 5 days or greater. Construction contractors other than NPS or Guidant that are brought on site to support a specific PRC, MERP, or outage project as identified by project managers. Contracted workers that are on site for a continuous period of time (e.g. 5 or greater continuous days i.e. Janitorial services). Part of fixed price, milestone payment, or other "turn key" type purchase agreement which represents the portion that is contract labor and performed on-site. Examples of included services are: Maxcom (telecommunication support), Assessment team support, Root Cause support, DZ Atlantic Group/Bartlett (RP Support), contractor Site Managers (with the exception of NPS). Excludes services with total annual cost <$15k, any materials included in the contract, and services provided on an "as needed" basis.

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Energy Delivery – Professional & Contractor Services Guidelines

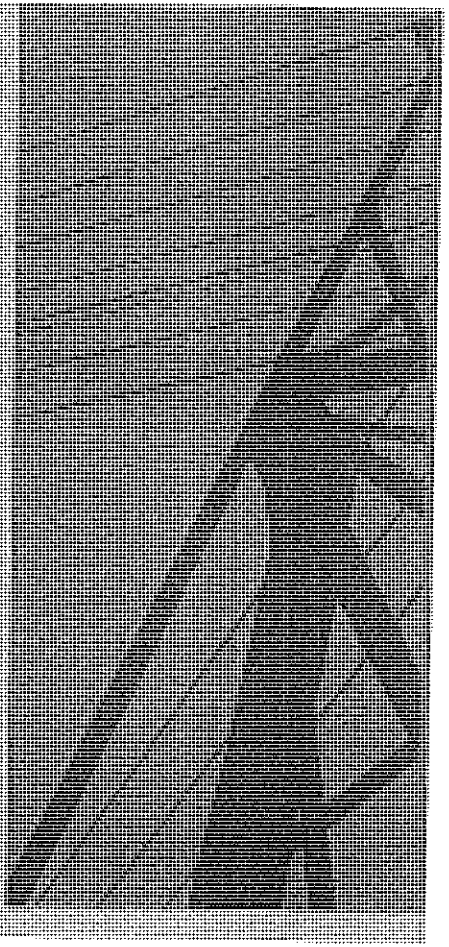
GL	GL Short Name	GL Long Name	General Description	FEU Description/Examples
550100	OutContrctProNonLeg	Outside Services/Contractors - Professional Non-Legal	Service Contracts for Unique skill sets that we don't do in-house	OSI inbound calling, Vendor services, Training
550210	OutContractEngineer	Outside Services/Contractors - Engineering	Engineering Expenses	Off-site engineering that is primarily in Transmission and Substation voltages.
550300	OutContract-Other	Outside Services/Contractors - Other	Other	Storms, Transmission aerial inspections, Facility improvements, Cable locating, Grass cutting, Snow removal, Janitorial, Heating, and Electrical repair
550310	OutContractTreeTrim	Outside Services/Contractors - Tree Trim	Tree trimming	Vegetation management
550320	OutContractTempAgnc	Outside Services/Contractors - Temporary	Temp hires not managed by a staff service provider.	Flaggers (Traffic control), Safety audits, Call-Center Temp Workers
550330	OutContrctEngDrawing	Outside Services/Contractors - Engineering Drawings	Engineering Drawings	Lightly used. Outside drafting distribution work. Roll into 550210.
550335	OutContrRepairRefurb	Outside Services/Contractors - Repair/Refurbishment/Overhaul of Plant Equipment	Outside Services/Contractors - Repair/Refurbishment/Overhaul of Plant Equipment	Outside Services/Contractors - Repair/Refurbishment/Overhaul of Plant Equipment
550500	ONSITECONSLT/ STFFAUG	On-Site Consultants/Staff Augmentation	Managed Service Provider	Guidant
550503	Envrmnt Wrk & Comp	Environmental Work and Compliance	Environmental	Claims follow-ups, Oil testing, and Clean-ups.
550506	CollAgencyCreditBur	Collection Agency - Credit Bureau	Collection Agencies	Revenue operations collections.

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FirstEnergy

Utilities International Planner
UIPlanner - Budget Advanced

February 2004



Ground Rules

- Please turn all cell phones and pagers off, or to silent setting
- Respect those speaking and asking questions by keeping side discussions to a minimum
- Please do not interrupt the person speaking
- All unanswered questions will be placed in the "Parking Lot" and answers will be distributed later
- Have fun and enjoy the opportunity to contribute to FirstEnergy's future success!

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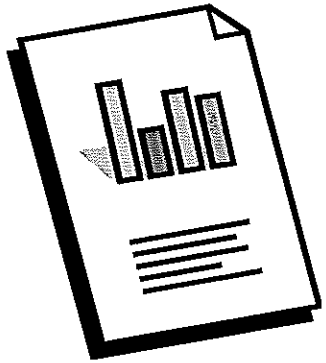
Financial Accountability Model

Financial Accountability Model

Vision – Establish a transparent financial view using standard SAP functionality

Why?

- Establishes "one source of the truth" for management reporting
- Increases accountability for total costs spent
- Reduces cost of ownership and customization of SAP



Conceptual Review

What is it?

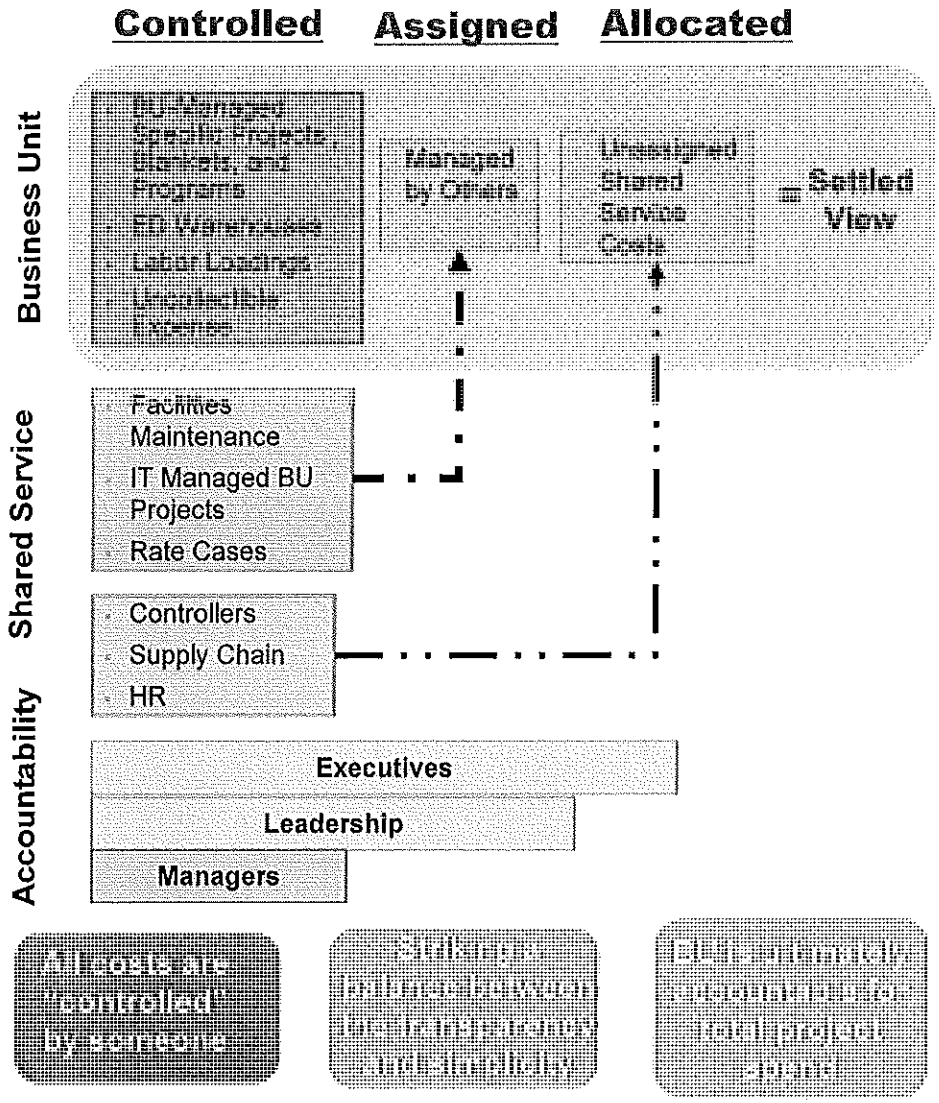
- Consistent financial view
- Establishes ownership for every dollar spent

Key Changes

- **Shift** accountability to **total spend**
- Changes in **roles and responsibilities** within budgeting process
- Changes in **level of reporting** and **reporting views**
- Changes in **target setting** within the business

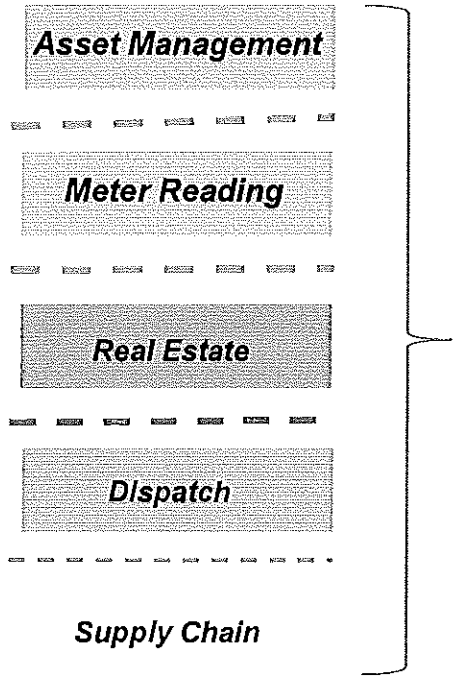
Business Impacts

- **People:**
  - Single owner accountable for total project spend, regardless of where costs originate
  - Increased roles and responsibilities for Project Owners
- **Process:**
  - Coordinate, manage, track budget and explain variances
  - Collaborate outside own organization
  - Reporting will be in alignment with the Accountability Model



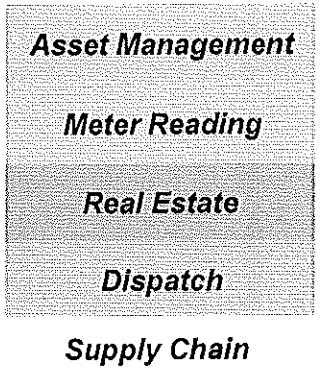
Total Project Ownership

Today



Individual ownership of pieces of a project budget

Post-Transformation



Single ownership of project budget

Outcomes

- ***One budget input for the total project including Labor & OTL***
- ***Required collaboration across the organization***
- ***Driving more comprehensive and consistent budget practices***

Roles & Responsibilities

- **Project Owners are responsible for:**
  - Developing, monitoring and updating budgeted and forecasted costs and revenues
  - Measuring and monitoring actual results, including explaining variances from budgets.
  - Collaborating with others when establishing their budgets, updating their forecasts, analyzing their actuals, and explaining variances between budget, forecast, and actual results
- **The responsibility for entering budgets and forecasts vary by Business Unit**
- **Standard financial management reports exist to support Cost Owners**

Business Unit Costs will be managed in one of two ways:

(1) Cost Owner Managed

- The labor, other-than-labor, and revenues will be assigned a specific owner (a cost center) in SAP
- Owners will be specific to each BU and each work type (e.g. blankets, programs, etc.)
- Includes Controlled, Assigned, and Allocated costs
  - *For a list of owners, by work type, by Business Unit, refer to the Financial Accountability Model policy on the FirstEnergy Today portal at: Communities>Finance>Policies and Procedures>FiT folder.*

(2) Line Item Managed

- Specific income statement line items not included above (i.e. interest expense, fuel, purchased power, etc.) will be centrally managed by defined group(s)
- This ownership is not assigned in the system but is implied based on the management of those revenues and costs

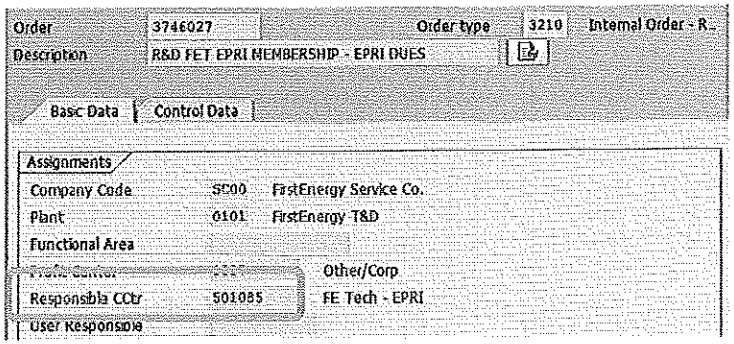
Illustrative Income Statement

Line Item	Ownership Type
Electric Revenues	
PJM/MISO Revenues	
Non-kWh Revenues	
Forfeited Discounts and Rental Revenue	
Miscellaneous Service Revenue	
Interest and Dividend Income	
Miscellaneous Revenues	
Other Income	
Other Revenues - Associated Company	
Total Revenues	
Fuel Total	
Purchased Power Total	
Fuel & Purchased Power	
O&M - Labor	
O&M - OTL	
Dues, Fees, Licenses	
Lease/Rental Costs Total	
General Business and Travel	
Materials and Equipment	
Professional and Contractor	
Uncollectible Exp	
Other OTL Total	
Other OTL Deductions	
Construction Overheads & Transportation	
Total O&M	
PJM/MISO Expenses	
State Reimbursed Programs	
Pension & OPEB	
Depreciation & Amortization	
Taxes, Other Than Income	
Operating Expenses - Associated Company	
Total Operating Expenses	
Operating Margin	
Service Company Billings	
Sale/Leaseback	
Interest	
Other Expenses	
Income Before Taxes	
Income Taxes	
Net Income	

Legend	
Controlled Costs + Settlements & Assessments	
Line Item Controlled	
Allocated	

How is Cost Ownership Assigned?

- **Representatives from each Business Unit were involved in assigning cost ownership to cost collectors**
  - Cost Owner field is a field on the SAP cost collectors called "Responsible Cost Center"
  - A Cost Owner is required on all cost collectors



- **A new cost center hierarchy, ZBWCAM0000, drives Standard Financial Management Reporting**
  - The hierarchy will provide line-of-sight into Controlled, Assigned, and Allocated costs

ZBWCAM0000 Accountability Model - CstCtr Hierarchy

- ZBWCAM1000 FEU
  - ZBWCAM1001 AYE Utilities
  - ZBWCAM1002 AYE Fed Reg Transm Segment
  - ZBWCAM1004 Compliance & Regulated Services
  - ZBWCAM1007 Customer Service
  - ZBWCAM1034 Distribution Support
  - ZBWCAM1068 ED and CS Senior VP
  - ZBWCAM1069 ED Safety Admin and Planning
  - ZBWCAM1070 Energy Efficiency Group
  - ZBWCAM1076 FE Utilities Admin
  - ZBWCAM1077 FERC - FE Utilities
  - ZBWCAM1098 Special Items - FEU
  - ZBWCAM1113 Transmission
  - ZBWCAM1127 Transmission Facilities Agreement
  - ZBWCAM1131 Utility Operations
- ZBWCAM2000 FES/FEG
  - ZBWCAM2001 FE Solutions
  - ZBWCAM3001 FE Generation
- ZBWCAM4000 Shared Services
  - ZBWCAM4001 AYE Other/Corp
  - ZBWCAM4002 Executive Administration
  - ZBWCAM4006 Finance Group
  - ZBWCAM4043 Human Resources Group
  - ZBWCAM4055 Legal and External Affairs
  - ZBWCAM4081 Special Items - Shared Services
  - ZBWCAM4085 Strategic Planning and Operations
- ZBWCAM9000 Unused

Benefits of Financial Accountability Model

- Identifies a single, accountable owner regardless of where costs originated
- Provides transparency and visibility into our financial statements
- Promotes an understanding of total spend by the work completed instead of a view by department
- Reduces customization and ad-hoc reporting
- Facilitates standard financial management reporting

Leadership Feedback:

- Overwhelming support for moving to one financial view
- Requires clearly defined guidelines
- Governance is required for sustainability

Q1) What is a 'Cost Owner'?

A. A Cost Owner is a cost center in SAP (not a specific individual) assigned to each and every cost collector.

Q2) How were Cost Owners determined for each cost?

A. A review was completed with each of the Business Services organizations to determine the appropriate Cost Owner for each dollar spent. Activities included:

- Validation of Cost Owner assignment to each cost collector
- Verification that Cost Owner hierarchy supports management reporting
- Comparison of "as-is" with "to-be" reporting and explanation of differences in reporting and accountability throughout the business
- Reconciliation of new reports to the existing internal reports/financial statements

Q3) Who are the Cost Owners?

A. Refer to the Financial Accountability Model policy, available effective January 1, 2014, for a list of work types and associated Cost Owners by Business Unit. The policy can be found on the FirstEnergy Today portal under Communities >Finance >Policies >FiT.

Q4) What if the Cost Owner disagrees with costs from another department?

A. The Cost Owner should discuss costs with the originating department. Changes to Cost Owners must be carefully controlled and are not permitted without prior approval. A process exists to request and receive approval for Cost Owner changes.

Refer to the Financial Accountability Model policy on the FirstEnergy Today portal at Communities>Finance>Policies and Procedures>FiT for more information.

Q5) When will the Financial Accountability Model be implemented?

A. It will form the foundation of all Reporting and Budget, Forecast, Planning activities beginning January, 1 2014.

Q6) The direct view (z8/z9) is going away. What do I use for my project or cost center reporting?

- Refer to chapter 2, Standard Financial Management reporting, of this training to understand the cost and labor reports available to you.

UIPlanner Software Overview

UIPlanner Overview

- Utilities International, Inc. is the leading provider of integrated planning solutions for utilities and related businesses

- UIPlanner (UIP) is a multi-user database system that supports Accounting and Finance functions

Planning
- Financial plans
- Strategic plans
- Regulatory plans

Treasury
- Daily forecasts
- Monthly forecasts
- Financing strategy

Tax
- Tax plans
- Tax strategies
- Actual taxes

Accounting
- Allocations
- Variance analysis
- Financial reporting

Budget Admin.
- Consolidation
- Administration
- Rolling forecasts

Regulatory
- Cost of service
- Rate design
- Clauses / riders

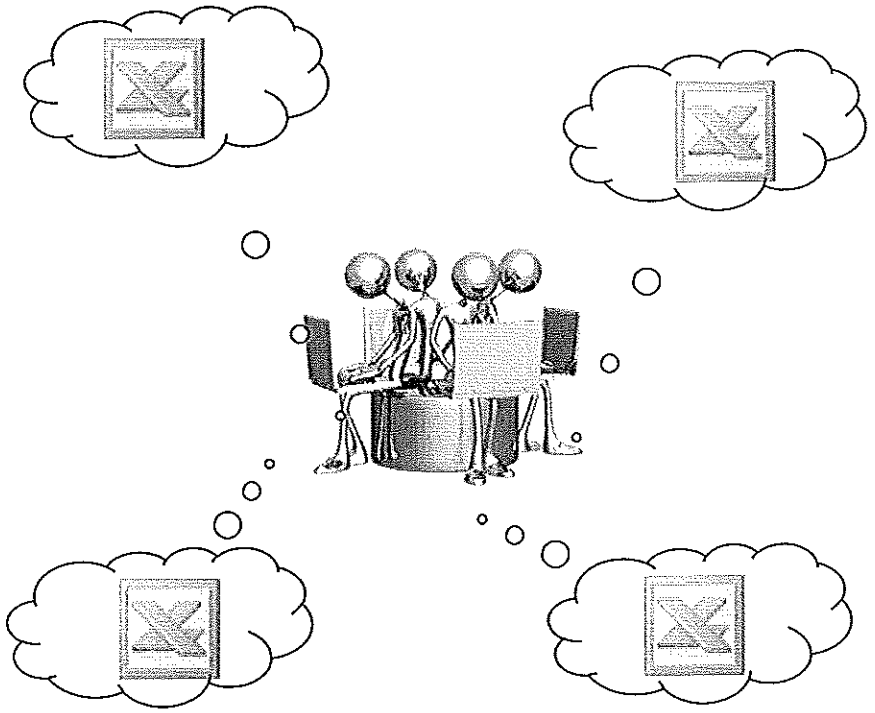
Customer Service
- Bill forecasts
- Analytics
- Energy Efficiency

Budget Users
- Unit-based budgeting
- Labor planning
- Project forecasts

Business Analyst
- Project evaluation
- Commitment tracking
- Performance analysis

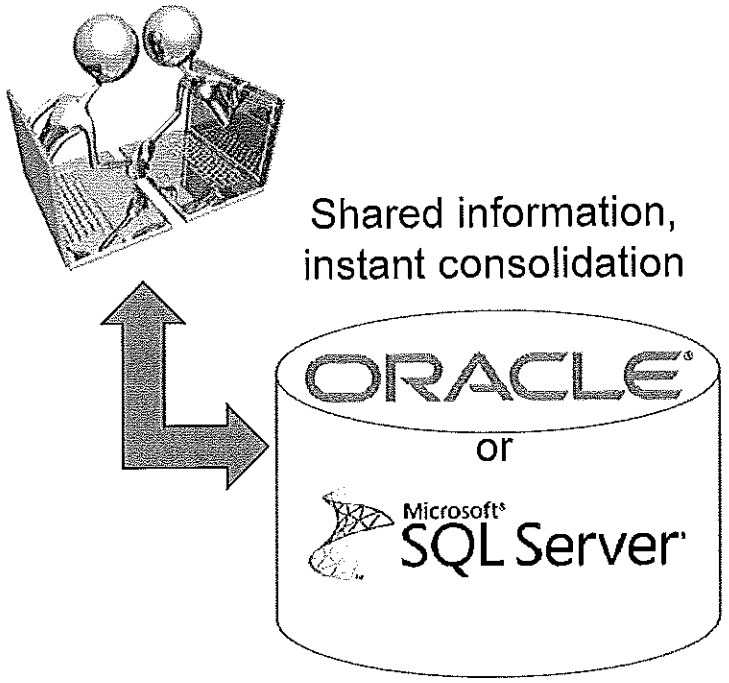
UIPlanner Overview

Individual Spreadsheets



Relies on manual processes to share and consolidate data

Integrated UIPlanner

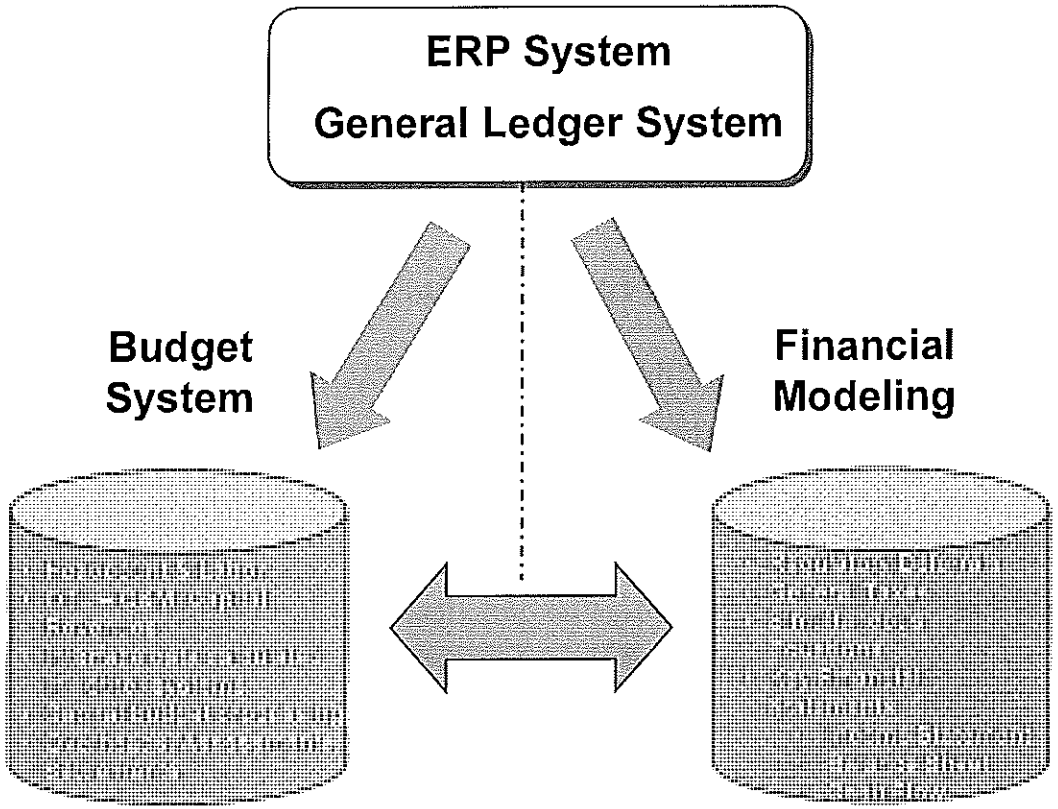


More productive, efficient, and less prone to error

UIPlanner Overview

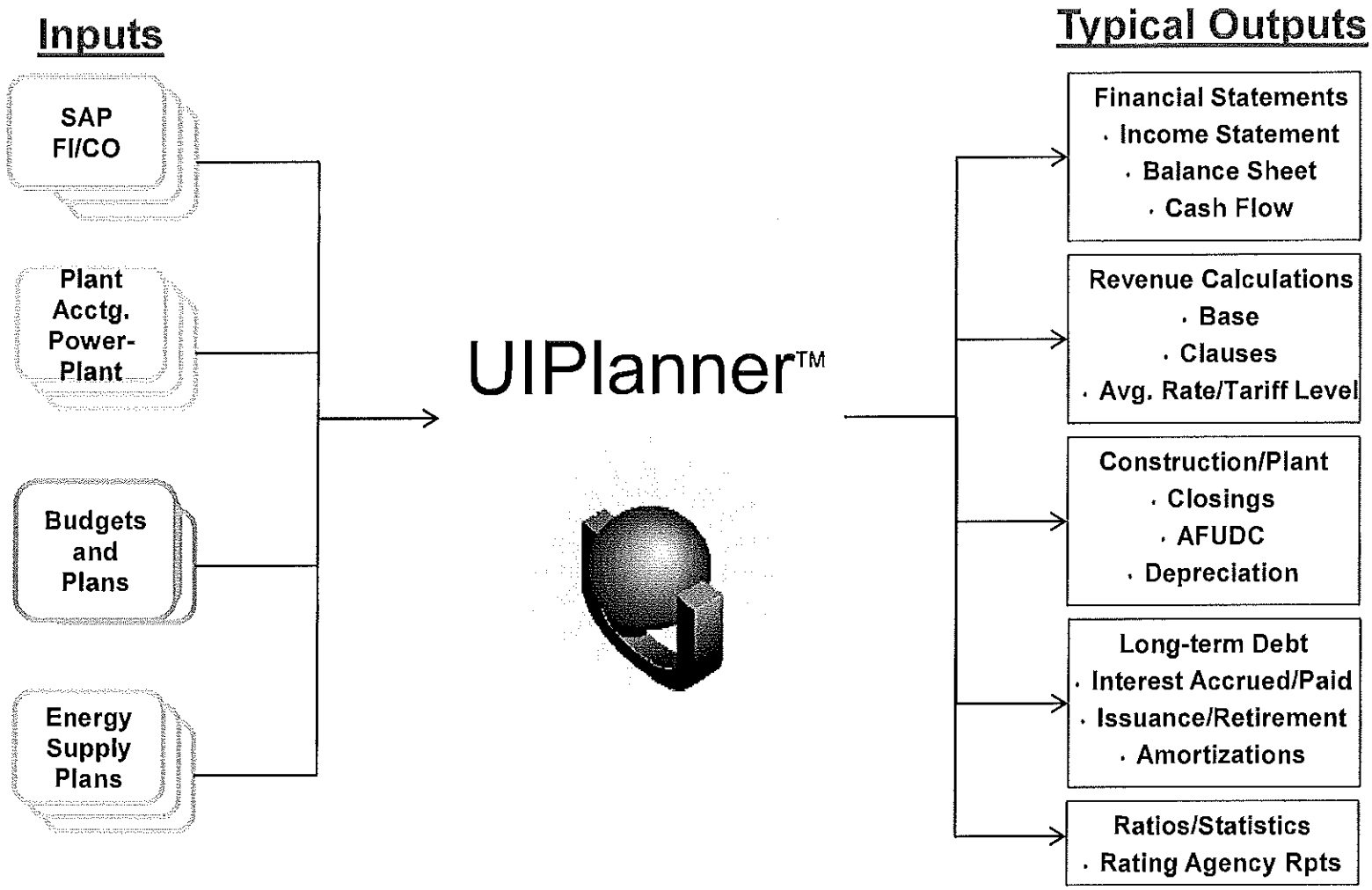
- UIPlanner can interface budget, forecast, plan results directly from a Company's ERP or General Ledger System to either the UIP Budget System or Financial Model

- Many Utilities utilize the Financial Modeling tool to manage their financial planning and regulatory outcomes



UIPlanner Overview

UIPlanner integrates data from multiple sources



UIPlanner Overview

Process Improvements

Move to multi-year forecasts

- Expand beyond current year
- Unlimited planning horizon (e.g. 5, 10, 20 year)
- Budget process practices

Improve variance explanation process

- Focus on business drivers
- Avoid unknown variances
- Shorten the cycle time to explain and respond

System Improvements

Technology for multi year forecasts

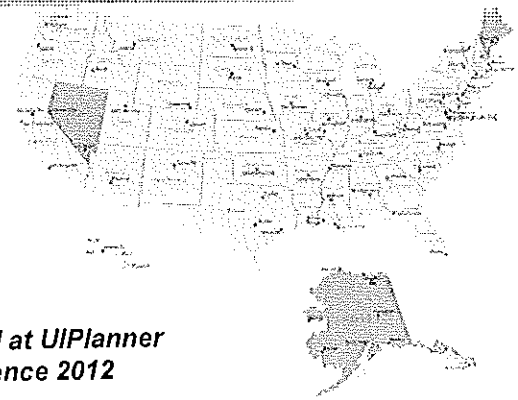
- Merge actuals with forecast
- Lock months of actuals
- Refer to prior forecasts

Technology for variance explanation

- Drilldown into logic and data
- Ability to add comments to reports by department/cost center

UIPlanner integrates all aspects of the budgeting and planning process

UIPlanner Overview



- **The 30 largest U.S. Utilities using the UIPlanner financial modeling tool – *not all clients shown are utilizing the UIPlanner budget entry system***
- **Proven across jurisdictions – regulatory calculations in 47 states**

Client list presented at UIPlanner Users Conference 2012

Exelon ✓ | Pacific Gas and Electric Company ✓ | AES ✓ | ✓ Sempra Energy | Ameren ✓

Duke Energy ✓ | Edison International ✓ | ppl ✓ | PSEG | Bonneville Power Administration

nationalgrid The power of action ✓ | MidAmerican Energy Holdings Company ✓ | Entergy ✓ | Xcel Energy ✓ | Northeast Utilities ✓

Southern Company Energy to Serve Your World ✓ | FirstEnergy ✓ | conEdison | nrg | CenterPoint Energy

FPL ✓ | TVA ✓ | Energy Future Holdings | ✓ DTE Energy | NiSource ✓

AEP ✓ | Dominion It all starts here ✓ | Progress Energy ✓ | elpaso | Los Angeles Department of Water & Power ✓

✓ = Client ✓ = Not client; attended conference

Budget Forecast Plan Key Process Overview

Key Process Changes

- Budget entry and analysis will not be managed in SAP. UIPlanner will now perform all budget related functions.

- Long-term planning (5 year) will be integrated with current year budget and forecast processes
  - Current year monthly and quarterly multi-year forecasting process is being implemented
  - Actuals will be interfaced to UIPlanner on a monthly basis
    - Cost collector, cost element and GL level
  - Transaction detail will not be interfaced to UIPlanner but will be available in the Common Data Source (CDS)
- Budget close processing performed within UIPlanner for all years entered
- Close process for actuals continues in SAP
- UIPlanner replaces xRPM as the Corporate capital planning tool and FES/FEG One List

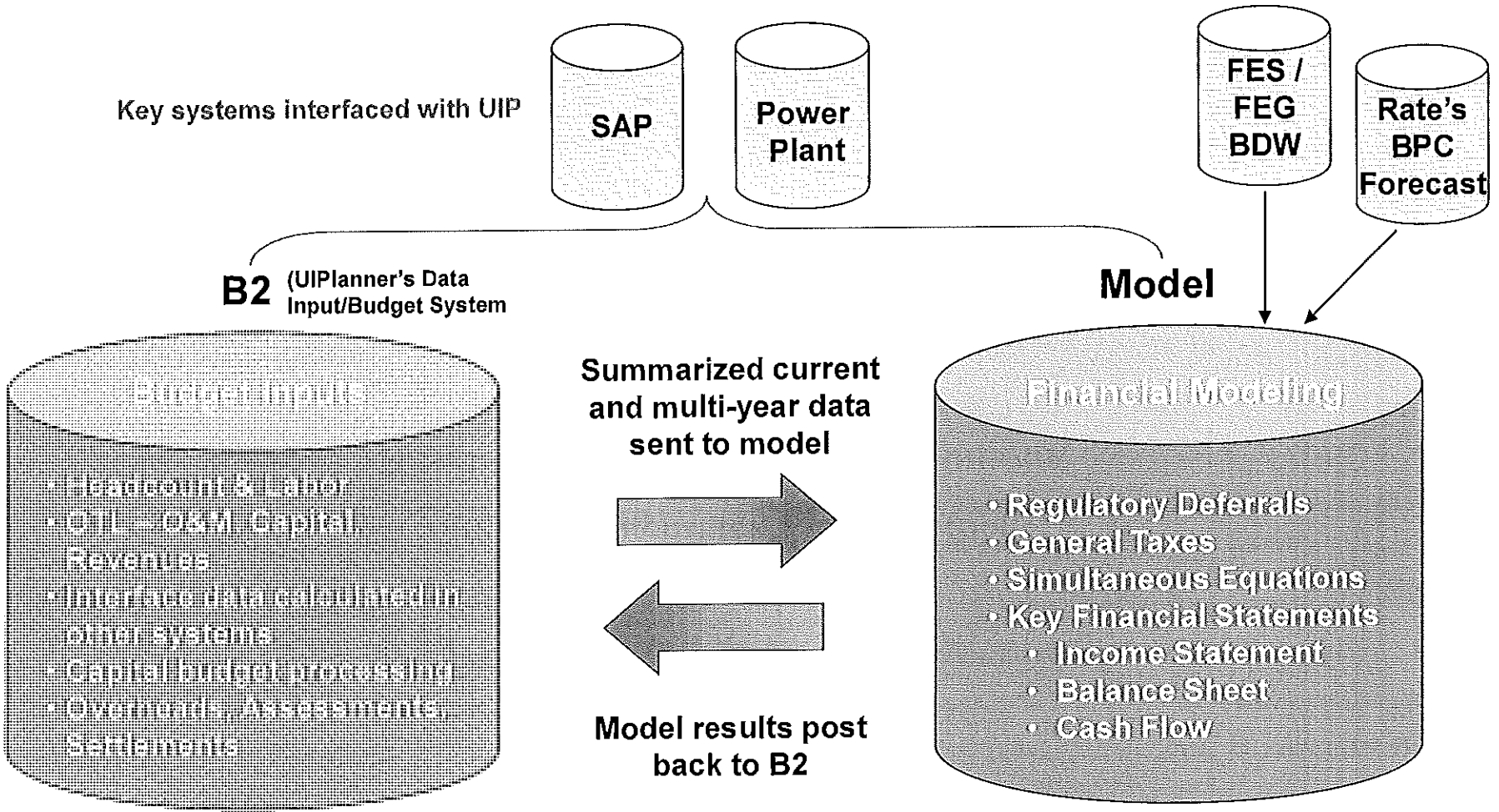
Key Process Benefits

- Consistent approach for budget, forecast, and plan; standard and efficient processes with integrated software tools
- Automated interfaces to source data reducing manual data manipulation
- Reduced cycle time to close budget
- UIPlanner replaces Midas (FE's current financial modeling tool) which is no longer supported by the vendor
- Monthly processing eliminates pencil changes and captures adjustments each forecast run
- Enhancement of integrated forward-looking scenario analysis for the company

The current year annual budget and forecast process provides the Company with a method to quantify and report the current year's expectations and help drive the Company toward achieving financial and operational objectives. The budget and forecast process also assists with facilitating the efficient usage of the Company's financial resources and allows the measurement of actual performance against projections.

Budget, Forecast, Plan Environment

UIPlanner Integrated Planning Tool
Current and Multi Year



Budget, Forecast, Plan Process

Today

Three separate processes for budget, forecast, and plan

Annual Budget

- Current year annual projection of staffing (employee headcounts), revenues, and expenses (Income Statement, Capital and Other)

Current Year Forecast

- Revised projection of the current year annual budget. Revisions to the current year annual budget (e.g. 3+9, 6+6, 9+3)

Multi Year Plan

- Two or more years of projected financials. Also referred to as the multi-year plan

Post FiT

Migrating to an integrated budget, forecast and plan process

A **Annual Budget / Multi Year Plan**

- Current year (year 1) annual projection of staffing (employee headcounts), revenues, and expenses (Income Statement, Capital and Other)
- Includes multi year plan (years 2-5) identifying business initiatives and primary business drivers

B **Current and Multi Year Forecast**

- Revised projection of the current year annual budget. Monthly revisions to the current year annual budget (e.g. 3+9, 4+8, 5+7, 6+6, etc.) and multi year plan with formal multi year reporting on the quarter close

Process Steps and Key Activities

A Annual Budget / Multi Year Plan

B Current and Multi Year Forecast

1 Maintain UIPlanner System & Process
- Create New Scenario (annual/monthly)
- Run Applicable Interfaces
- Develop / Update Budget, Forecast Plan Guidelines
- Create Annual Activity Prices
- Perform Other System Functions

2 System Entry
- Employee Labor
- Allocate Labor and Non Labor
- Create/Maintain Budget Group Budget Items
- Project Planning and Tracking
- Validation Reporting
- Business Unit/Department Center Locking

3 System Administrator Activities
- Validation Reporting, Center Locking, Budget/Forecast Close, Derive FERC

4 Financial Modeling
- Move B2 Results to Model
- Move Model Results to B2

5 Reporting
- Move Processed Financial Results to Common Data Source
- Standard Reporting

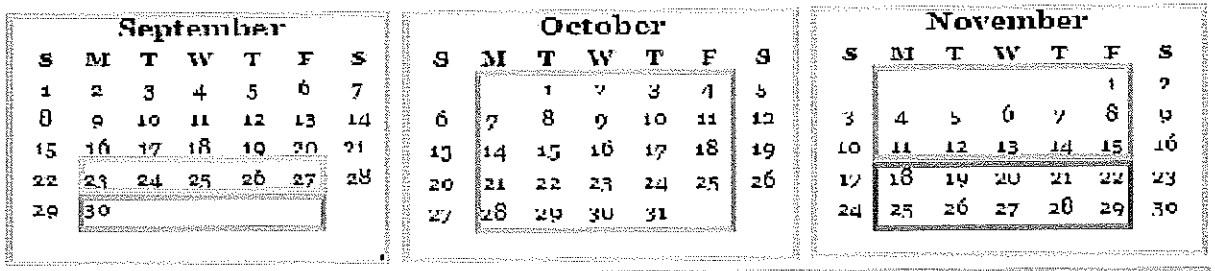
Annual Budget / Multi-Year Plan Process

Annual Budget / Multi-Year Plan Process

A Annual Budget / Multi Year Plan Process

- Traditionally starts late third quarter each year
- Results available for November Board Meeting – approval of five year plan

Year 1

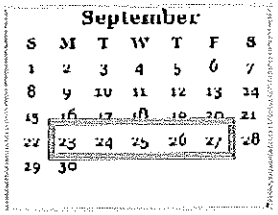


Years 2 - 5

- **Key Activities**
  - Create New Scenario (annual)
  - Run Applicable Interfaces
  - Develop Budget, Forecast, Plan Guidelines
  - Calculate Annual Activity Prices
  - Perform Other System Activities
  - Employee Labor
  - Allocate Labor and Non Labor
  - Create/Maintain Budget Group Budget Items
  - Project Planning and Tracking
  - Validation Reporting
  - Business Unit/Department Center Locking
  - System Administrator Functions
    - Validation Reporting, Center Locking, Budget Close, Derive FERC
  - Move B2 Results to Model
  - Move Model Results to B2
  - Move Processed Financial Results to Common Data Source
  - Standard Reporting

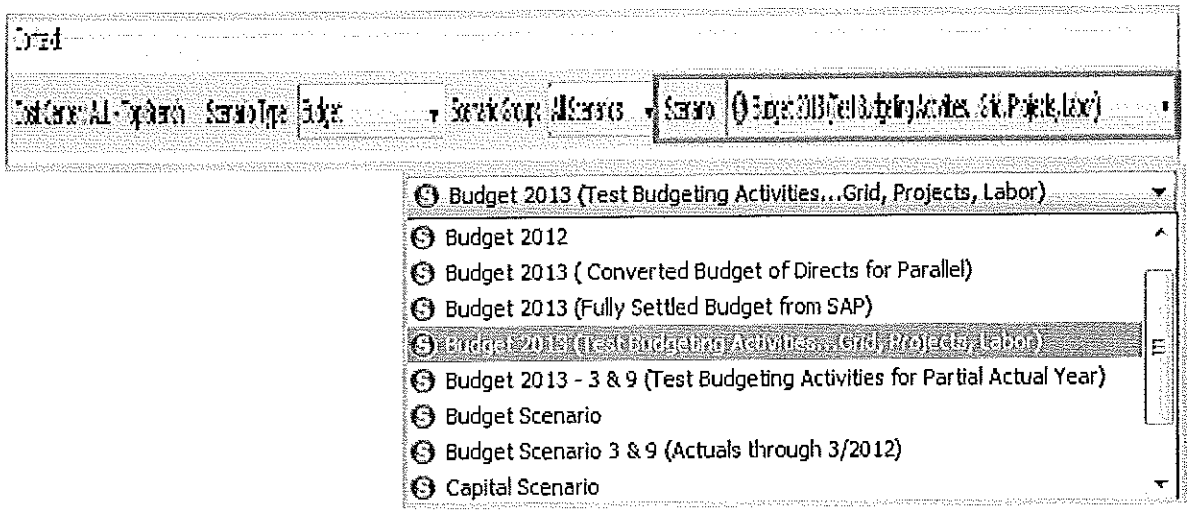
Annual Budget / Multi-Year Plan Process

1 Create New Scenario



Scenarios are similar to versions in SAP. UIPlanner will manage all the different scenarios needed throughout the year for the budget, forecast, and plan process

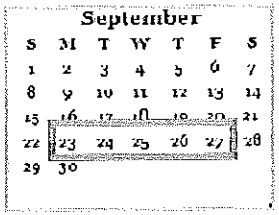
- A new scenario will be created for the annual budget process and for each monthly forecast update
- Additional scenarios can be created based on management's request
- Available scenarios will be listed via drop down box on the main menu



Annual Budget / Multi-Year Plan Process

2 Run Applicable Interfaces

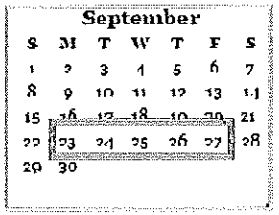
SAP will interface data to UIPlanner near real time, nightly and monthly



Near Real Time	Nightly	Monthly
• Cost Centers • Orders • Projects *(WBS project definition and WBS elements)* • Cost Elements • General Ledger Accounts • Profit Centers	• Activity Types • Companies • All related trees	• Controlling Actuals • General Ledger Actuals • Overheads • Assessments • Settlements • FERC • HR employee data • Power Plant
• Users will continue to create and manage master data in SAP • Near real time approximately every 30 minutes • On demand available	• Individual data fields available near real time – actual tree update will occur nightly	• Actuals loaded to support monthly processing • Budget close performed in UIPlanner • On demand available

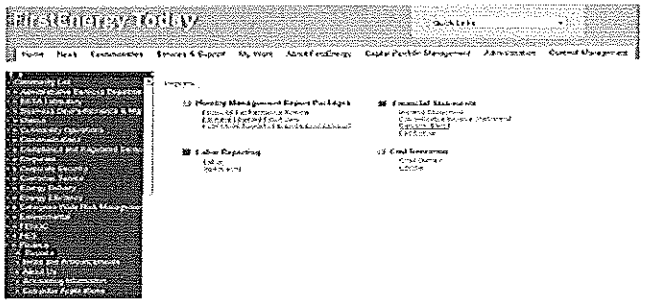
Annual Budget / Multi-Year Plan Process

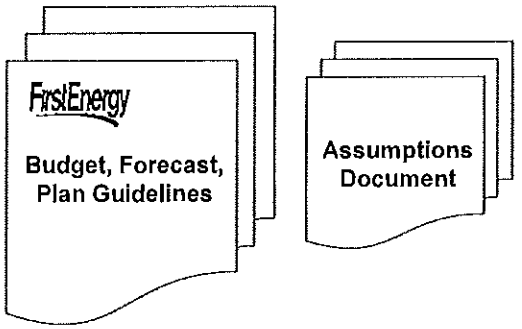
3 Develop Annual Budget, Forecast, Plan Guidelines



Guidelines will be developed and maintained to assist persons responsible with the direct input of data into UIPlanner as they prepare the annual, budget, forecast and plan

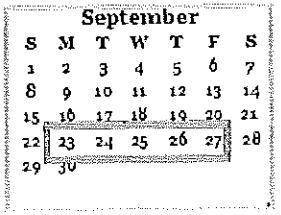
- Guidelines will cover the annual process along with the current year and multi year forecast process. Items included will cover annual calendar of events, plan assumptions, timing, person responsible and applicable targets
- Related processes such as creating and maintaining master data, financial accountability model guidelines, and reporting will be included (other FiT linked processes)
- A common data repository will be available on the FE Portal under the Finance Community. Key documents will be stored to facilitate the budget, forecast, plan process. Available in 2014
- Guidelines will be updated throughout the year, if needed, to reflect major changes as part of the monthly/quarterly forecast process





Annual Budget / Multi-Year Plan Process

4 Calculate Annual Activity Rates

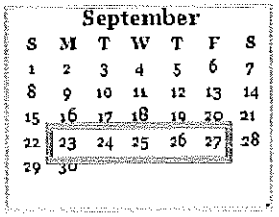


Annual activity rates will be calculated in UIPlanner prior to the start of the annual budget process. SAP HR employee data will be interfaced to UIPlanner to support this process

- **Run HR interface**
  - Import Employee data containing employee salaries, vacation, PAD, holiday, etc,
- **Calculate employee loaded salary**
  - Labor additives (benefits, incentive compensation, payroll taxes)
  - Update union and non union wage schedules
- **Calculate productive hours by employee**
  - Vacation, PAD, holiday, meetings, and other non productive
- **Calculate activity rates**
  - Total dollars / total hours
  - Rates will be automatically calculated for the plan horizon

Annual Budget / Multi-Year Plan Process

6 Perform Other System Functions



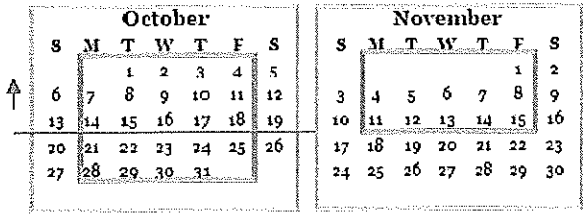
Other activities include administering user security, maintaining global assumptions, ensure system validations are current, publishing datasets and reports, etc.

- **Administer user security**
  - Add, edit, delete
  - Maintain FERC code of conduct and required reporting
- **Maintain global system assumptions**
  - Update related datasets
- **System Validations**
  - Maintain rules and validations for appropriate screens
  - Maintain interfaces
- **Other Miscellaneous**
  - Publish standard reports
  - Trouble shoot system problems
  - General system maintenance

Annual Budget / Multi-Year Plan Process

6 Employee Labor

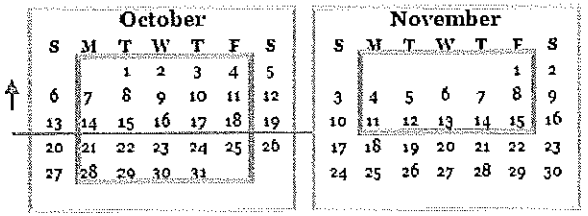
View and verify SAP HR interfaced employee data



- SAP HR data will be interfaced to UIPlanner initially for calculation of activity prices but also monthly to show employee changes and unproductive time usage
- Verify employee data - employee names, cost centers, etc.
- View/update labor data at the individual employee or summary cost center level
- Additional employee information such as vacation eligibility, available payroll hours, etc will be summarized to help facilitate building of the labor budget and monthly forecast process
- Access to the labor screens will be secured based on role and business unit/department
- User will be presented with hours and dollars at the individual employee level and summary level by Company, Cost Center, Pay Calendar, Personnel Subarea, Activity Type

Annual Budget / Multi-Year Plan Process

6 Employee Labor *(continued)*

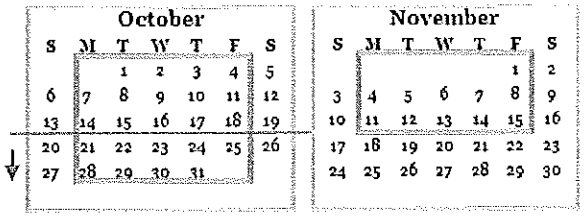


Determine number of headcounts, FTE's, vacation and PAD allocation, total hours, and total dollars by either individual employee or summary level

- Verify employee data - employee names, cost centers, etc.
- Update staffing - headcounts and FTE's
  - Additions
  - Exits (planned retirements)
  - Internal transfers
- Allocation of unproductive time - PAD, vacation, deferred vacation
- Manual salary adjustments - promotions, non ICP bonuses
- Determine overtime hours or dollars
- Note: Other than labor entry can also occur in conjunction with developing employee labor
- Cost Center Labor Hours and Dollars Available to budget in grid

7 Allocate Labor and Non Labor

Allocate hours and dollars to the various cost collectors (cost center, internal order, WBS) for capital and noncapital

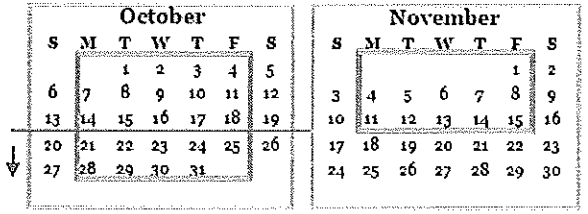


- System design follows the Financial Accountability Model where each cost collector has one owner
- Cost collector owners will be responsible for budgeting and forecasting all other than labor
- Master Data guidelines will be in place to ensure consistency across the Company
- Cost collector combinations are entered into UIPlanner via a budget grid or Excel upload
  - Budget records will be displayed for the active department or cost center selected
  - An additional project screen available to further define budget inputs
- Both hours and dollars available on grid
- Contractor hours/dollars calculation available to assist users with developing their other than labor budgets

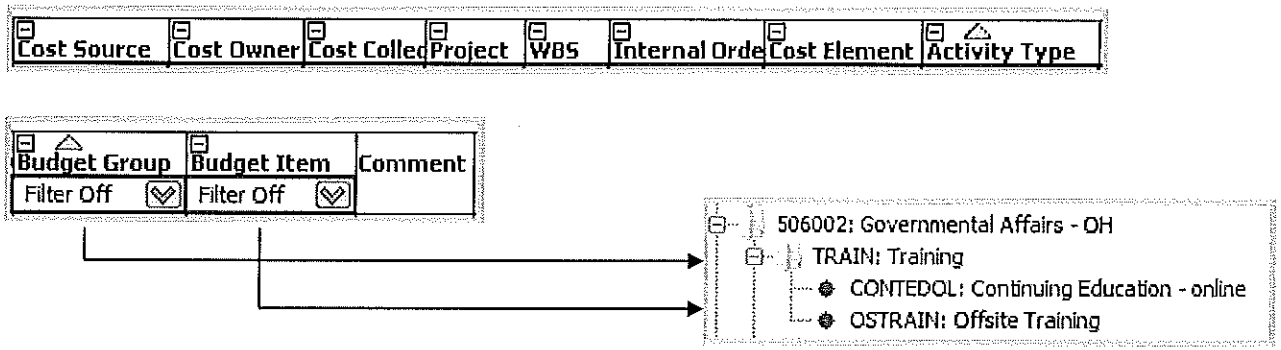


8 Create / Maintain Budget Group Budget Item

Budget groups and budget items will be utilized as part of the budget grid entry to further categorize data inputs. Utilized to assist with budget/forecast approvals. Data fields are optional



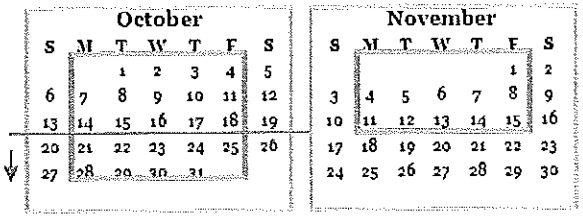
- Budget groups and budget items can be assigned to any node in the cost center tree
- The availability for use will depend on the assignment and level in the cost center tree
  - If a budget group budget item is assigned to an individual cost center then it will only be available for use with a grid combination for that particular cost center
  - Budget group and budget items set at the "all node" or top level will be available for all users



Annual Budget / Multi-Year Plan Process

9 Project Planning and Tracking

A separate project screen is available where users can house additional project information in one common place. Planning projects can be created in UIPlanner to assist with long term planning

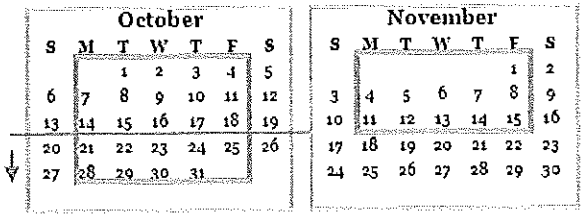


- Users will input additional project information such as project description, project sponsor, project status, etc for both SAP projects and UI Planning Projects
- Project attributes will be both required and optional
- UIPlanner will allow users to create projects for multiyear planning without having to create the project definition and WBS elements in SAP
- "Project Templates" will be interfaced and utilized from SAP as a starting point
  - Allows the project attribute values of the SAP project to be applied to the new Planning Project (project definition and WBS element level)
  - Mirroring the SAP project to the UI Planning Project ensures important attributes such as the costing sheet data is applied accurately
- When planning projects are approved during the budget year, the project definition and WBS elements will be created in SAP and interfaced in UIPlanner

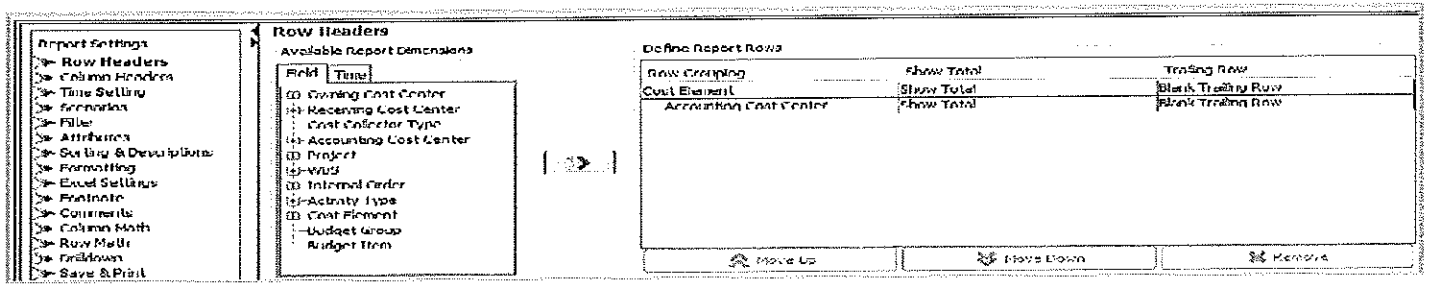
Annual Budget / Multi-Year Plan Process

10 Validation Reporting

System validation reports will be available to check user entry for budget and forecast inputs

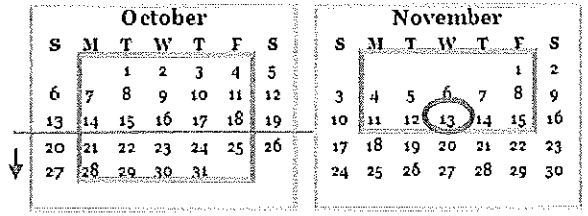


- UIPlanner reports will be available to validate system entry
- Multiple ways to view data
  - **View Reports -** standard reports by major category
  - **Create Reports** - on-the-fly reporting - menu driven. Ability to edit report rows and columns, add and delete fields, subtotal and total, formatting
  - **Report Administration** - enables user to create reports you want to quickly rerun, distribute, or edit in the future
- Certain data fields will be derived through reporting such as cost type, company code, profit center, etc.



Business Unit / Department Center Locking

Business Unit/Department approval will be required. Select users will be able to lock the cost centers for their respective areas prior to the final budget close

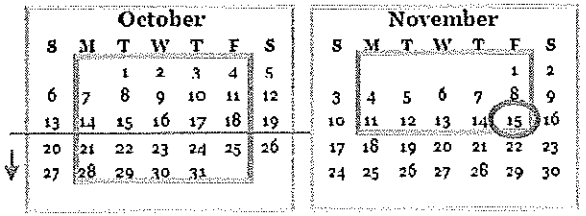


- Select users will be granted access to lock their individual business unit/department cost centers or entire group/department once the Business Unit Controller/Department Head has reviewed and approved the results
- Center locking will be considered an approval and signifies to the System Administrator that the group has completed their work and is ready for final processing
- Center locking is date stamped and identifies who locked and at what time

Annual Budget / Multi-Year Plan Process

12 System Administrator Activities

System Administrator will perform additional activities to finalize the budget/forecast process



- **Validation Reporting**
  - Verify all areas are locked
  - Review miscellaneous reports

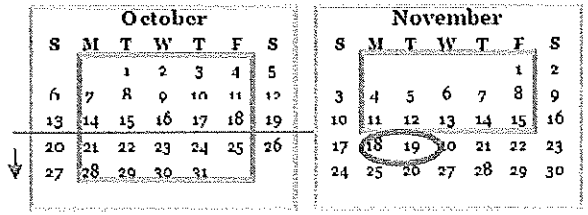
- **Administrator Center Locking**
  - Once the Business Unit/Department locks their individual groups, the System Administrator can perform an administrative lock over the entire cost center tree which signifies the scenario has been locked
  - System Administrator has the authority to open up individual centers for a particular user in the event a budget correction is needed

- **Budget / Forecast Close Process**
  - The Budget Close will be processed in UIPlanner and System Administrator will run the budget close at different intervals of the process giving the user insight into the final settled numbers
  - The close will process all years in scenario
  - A schedule will be published as part of the budget guidelines allowing users to plan accordingly
  - Budget close processing time is expected to be significantly shorter than FE's current process. Exact time for compiling and run time is not yet known
  - FERC will be derived as part of the close process

Annual Budget / Multi-Year Plan Process

13 Move B2 Results to Financial Model

Select budget entry items will be migrated from B2 to the Financial Model for further processing



- Dependent data items (interest, deferrals / riders, income taxes, general taxes) are calculations that will be automated in the model

- The model "links" the calculation of dependent data
  - Eliminates the need for manual handoffs
  - Allows for quick turnaround of changes

- New process will generate integrated financials, not just an Income Statement
  - Better insight on cash impacts
  - Monitor key financial drivers including regulated entities rate base

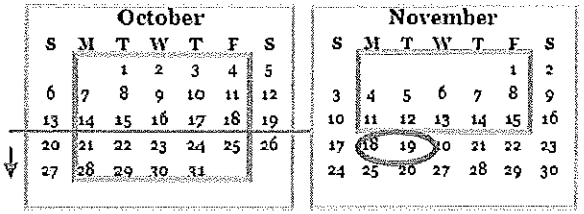
- Separate model security limits access to data
  - Not all B2 users will have access to the financial model

- Additional Model activities
  - Creating scenarios and "what if" analysis
  - Target setting and financial metrics

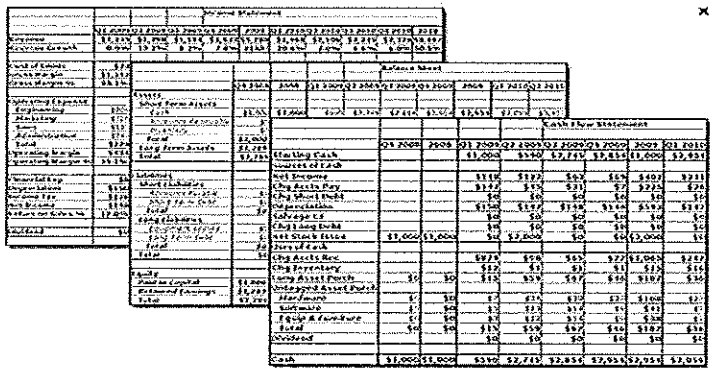
⇒ *Develop internal multi-year financial guidance and targets*

14 Move Financial Model Results to B2

Once model processing occurs, results will be posted back to B2 for users to view. Level of details and posting method is still under development



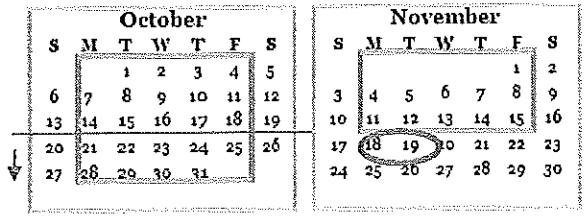
- Results from the data calculations within the model will be posted back to the B2 environment
- Calculated results will be available to view within a dataset and report
- Owners will review and validate results as part of process
- The key financial statements (income statement, cash flow, balance sheet) will also be generated as part of model processing
- Internal income statement results will be available for users to view in B2



Annual Budget / Multi-Year Plan Process

15 Move Processed Financial Results to Common Data Source

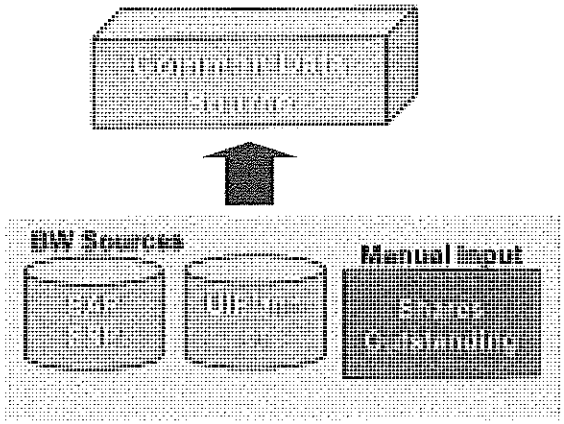
Provide standard management reporting sourced from a single, common database. Standard reporting available to ensure results are viewed consistently across the organization



- **Final processed results will be moved to the Common Data Source**
  - Separate Summary Cube allows faster report processing
  - Separate Detailed Cube simplifies variance analysis
  - Multi-year forecast data will not be sent to the BW

- **FiT Available Reports**
  - Financial Statements,
  - Monthly Management Reports
  - Cost Reporting
  - Employee Labor Reporting

Source Systems



Current and Multi-Year Forecast Process

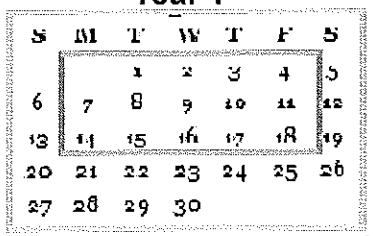
Current and Multi-Year Forecast Process

B

Current and Multi-Year Forecast Process

- Recast current month and remaining months in current year
- Update of multi-year plan
- Standard reporting will be utilized with fixed timing (FiT Reporting)
- Forecast results available each month to manage current and multi year

Year 1



Years 2 - 5

- **Key Activities**

1
- Create New Scenario (monthly)
- Run Applicable Interfaces (monthly)
  - Update Budget, Forecast, Plan guidelines
  - *Calculate annual activity prices (N/A)*
- Perform Other System Activities (if needed)
  - *Move B2 Results to Model*
  - *Move Model Results to B2*
  - *Move Processed Financial Results to Common Data Source*
  - *Standard Reporting*

2
- Employee Labor
- Allocate Labor and Non Labor
- Create/Maintain Budget Group Budget Items
- Project Planning and Tracking

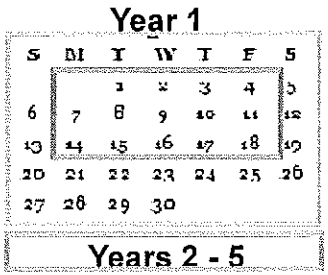
→ Reflect labor and non labor changes

  - *Validation Reporting*
  - *Business Unit/Department Center Locking*
- *System Administrator Activities*
  - *Reporting, Center Locking, Budget Close, Derive FERC*

Current and Multi-Year Forecast Process

1 Maintain UIPlanner System & Process

The current and multi-year forecast process will follow the same steps as the annual budget/multi-year plan process with several activities being modified to reflect monthly versus annual



- Create New Scenario
  - Create new version to capture recast
- Run Applicable Interfaces
  - Interface SAP monthly actuals (budget level)
  - Interface HR employee data
- Update Budget, Forecast Plan Guidelines
  - Update scenario assumptions (if needed)

Actuals load to UIP ***Recast remaining months and multi year***

Amount Type	2013					
	2013 - Jan	2013 - Feb	2013 - Mar	2013 - Apr	2013 - May	2013 - Jun
Dollars	$35	$35	$35			
Hours	1.0	1.0	1.0			

Reference row available to compare values from previous scenarios

Amount	2013	2014	2015	2016	2017	2018
Type	2013 Total	2014 Total	2015 Total	2016 Total	2017 Total	2018 Total
Dollars	$0	$0	$0	$0	$0	$0
Hours	0.0	0.0	0.0	0.0	0.0	0.0

Current and Multi-Year Forecast Process

2 System Entry

Users will identify changes and reflect labor and other than labor changes

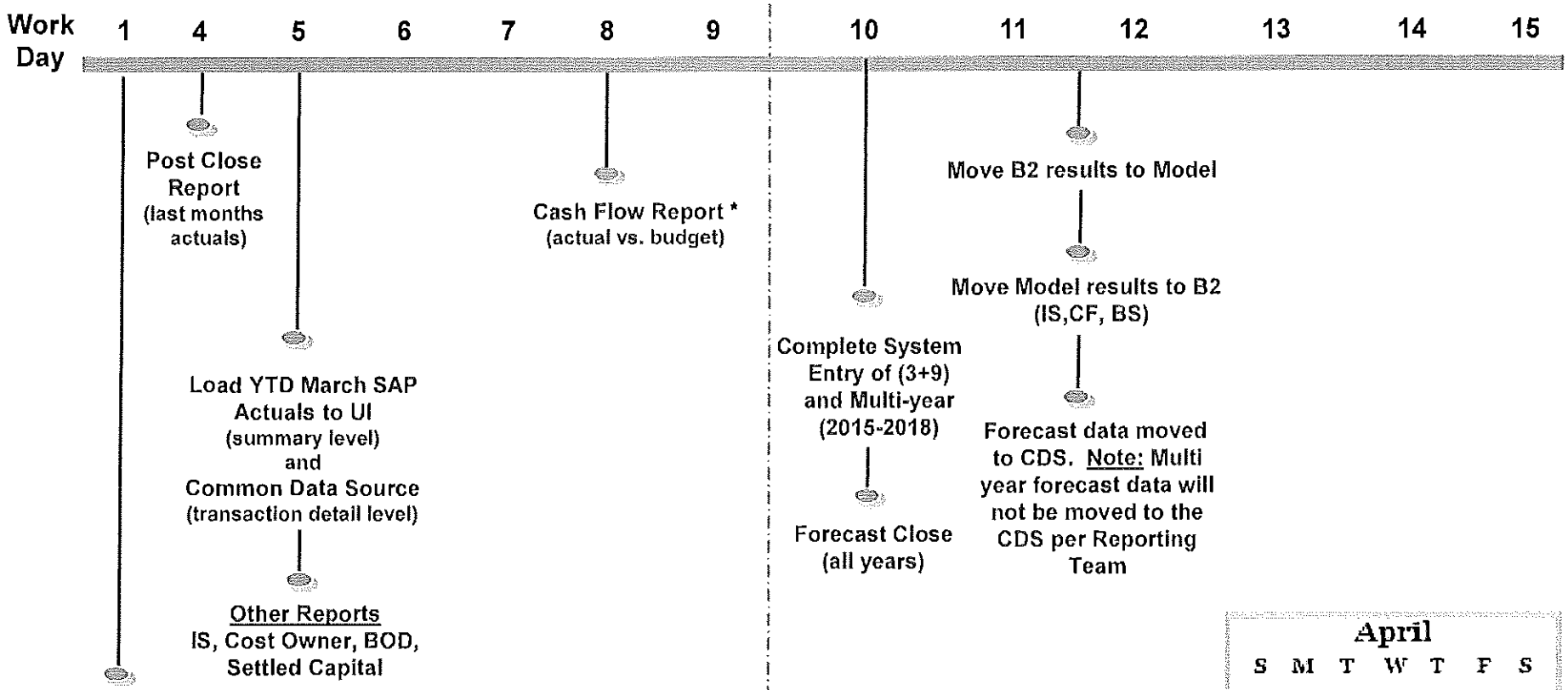


- Employee Labor
  - SAP HR data will be interfaced to UIPlanner initially for calculation of activity prices, but also monthly to reflect employee changes such as pay adjustments, vacation and PAD usage
  - Interface will automatically run the first workday each month
  - Labor balances should be reviewed as part of the forecast process
- Allocate Labor and Non Labor
  - Adjust cost collector dollars/hours for remaining months
- Create/Maintain Budget Group Budget Items (optional)
  - Create new budget groups budget items to capture new cost collector additions
- Project Planning and Tracking
  - Identify new projects
  - Identify project changes and status

Current and Multi-Year Forecast Process

Illustrative

- Schedule included with annual guidelines
- Standard reports will be utilized to manage results



- New scenario created for 3+9. System open for entry
  (scenario can be created in previous month)
- Run applicable interfaces (e.g. monthly HR data)

Specific calendar days will utilize standard reports

- System generated cash flow reports will not be available until BPC go-live 5/9/14. Actual to budget/forecast cash variance reporting will continue to be created using the current process

April

S	M	T	W	T	F	S
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23	24	25	26
27	28	29	30			

- **Multi-Year Plan / Forecast**
  - Performed in conjunction with the annual and monthly forecast process
  - Multi year approach
    - Focus on one year out (year 2) – identification of known key events and business unit initiatives
    - Years 3 - 5 identification of primary business drivers
  - Allow users the ability to develop a detailed forecast or adjust at a summary level
  - Budget close will process all years in scenario

Build and refine forecast data for detailed annual budget
Ability to align earnings and cash projections with long-term strategy

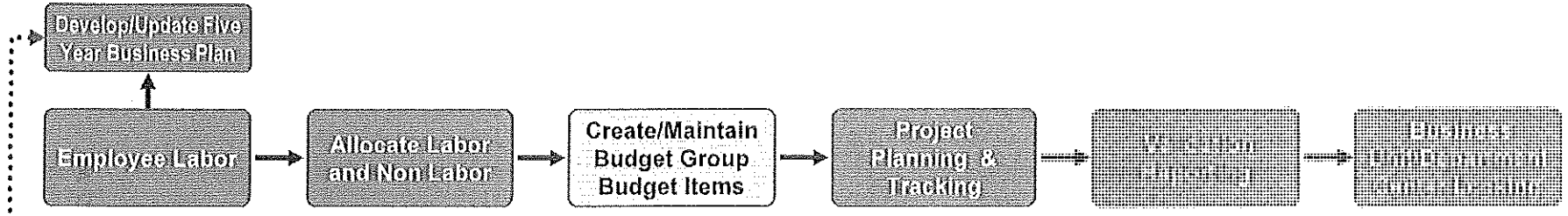
Year 1 (current year)	Year 2	Year 3	Year 4	Year 5
Annual Budget	**Multi-Year Plan / Forecast**			
Current Year Forecast				
• Cost center level details • Identification of specific capital and noncapital projects • Identified strategies • Execute and monitor performance	• Known key events • Business Unit Initiatives	• Primary Business Drivers		
	Key Variable Inputs			
	• *Load* • *Special programs (e.g. forestry, energy efficiency)* • *Transmission* • *Regulatory strategy* • *Power prices* • *Plant outages* • *Fuel*	• *Human Resources special items* • *Tax strategies* • *Treasury activities* • *Accounting treatment* • *Business development strategies*		

Budget, Forecast, Plan Process Summary

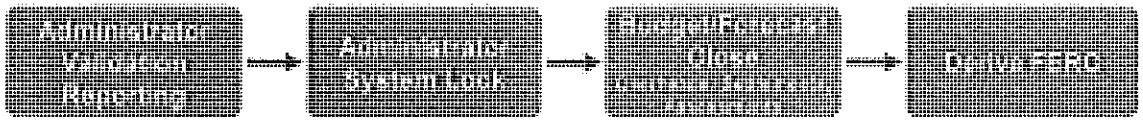
1. Maintain UIPlanner System & Process



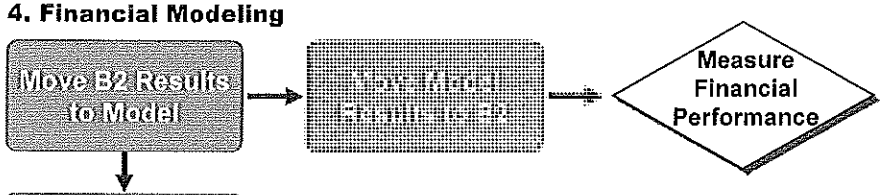
2. System Entry



3. System Administrator Activities

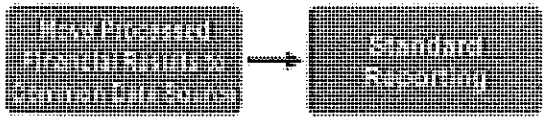


4. Financial Modeling



- *Improve decision making with what-if analysis*
- *Identify and implement financial initiatives and strategic alternatives*
- *Develop internal multi-year financial guidance and targets*

5. Reporting



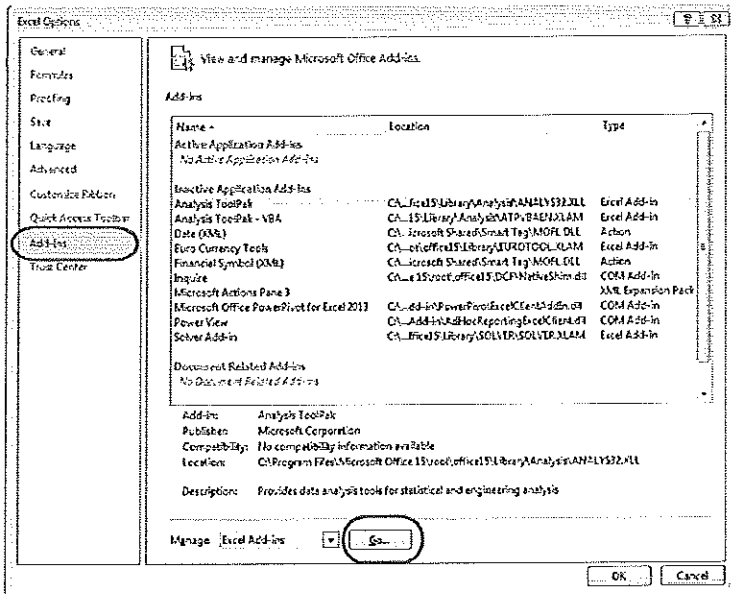
UIPlanner Log In Process

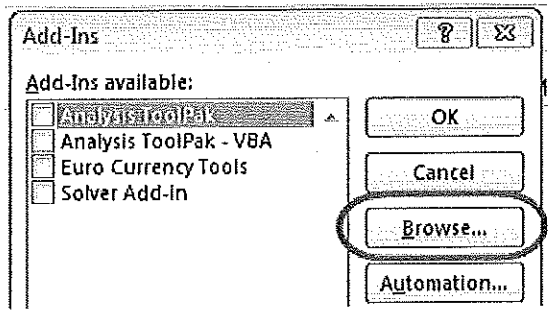
Install Excel Add-Ins

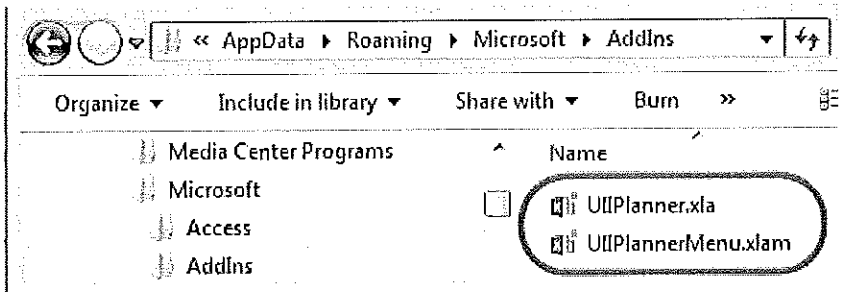
- **UIPlanner Excel Add-Ins are used for Excel upload / download functionality**
- **Add-Ins are User ID and computer specific**
- **Follow these steps to copy the Add-Ins files to your Excel session on the computer you will use to access UI Planner**
  - **Step 1 – Locate the files to be copied**
    - Open Windows Explorer, navigate to the U: shared drive to your appropriate group folder and leave this window open.
      - U:\FE\Competitive - FES\FiT Project\UIPlanner\Excel Add Ins
      - U:\FE\EnerAff\FiT Project\UIPlanner\Excel Add Ins
      - U:\FE\RegEnt\FiT Files\UIPlanner\Excel Add Ins
      - U:\FE\ShrSvc\FiT\UIPlanner\Excel Add Ins
  - **Step 2 – Copy the files from the U drive to your C drive through Excel**
    - Follow the instructions pertaining to your version of Excel (see next slides)
    - Excel will direct you to where the files should be copied
  - **Step 3 – Confirm the Add-In was installed**
    - Follow the instructions pertaining to your version of Excel (see next slides)

Excel Add-Ins – Step 2

- **For Excel version 2010 or 2013**
  1. Open Excel (version 2010 or 2013)
  2. Click File > Options
  3. From the Excel Options window, select **Add Ins** then click **GO**
  4. From the Add Ins pop up, click **Browse**
  5. Excel will take you to the location where the files should be (It will be empty)
  6. Navigate to your Windows Explorer session and copy the two Add-In files
  7. Navigate to your Excel session and paste the two files into the 'AddIns' folder Excel has selected for you

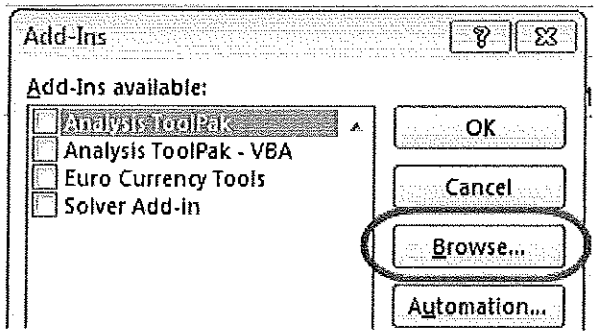


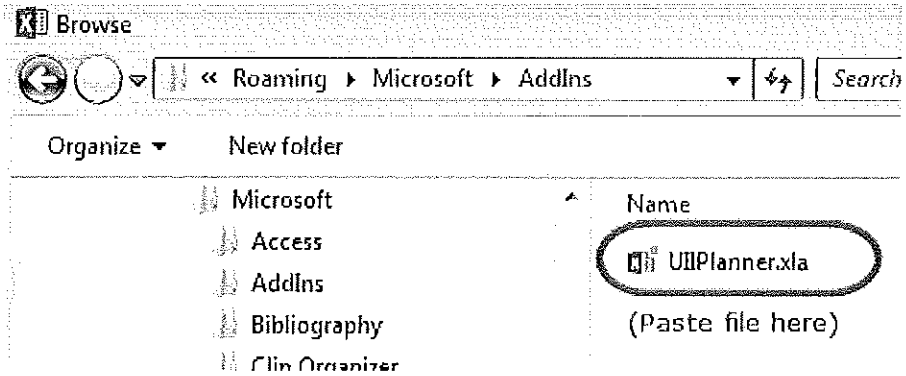




Excel Add-Ins – Step 2 (continued)

- **For Excel version 2003 or 2007**
  1. Open Excel
  2. From the menu bar, select Tools > **Add Ins**
  3. From the Add Ins pop up, click **Browse**
  4. Excel will take you to the location where the files should be (It will be empty)
  5. Navigate to your Windows Explorer session and copy one Add In file UIPlanner.xla
  6. Navigate to your Excel session and paste the file into the 'AddIns' folder Excel has selected for you

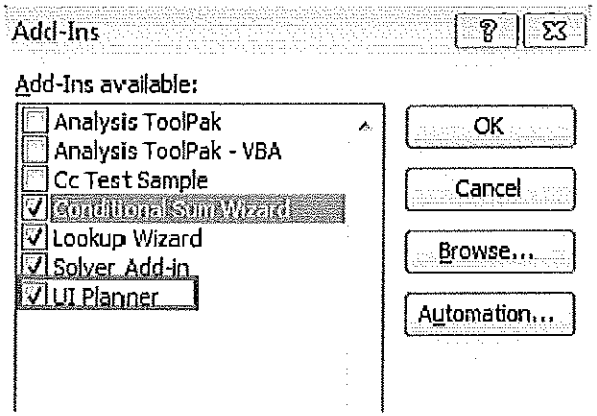




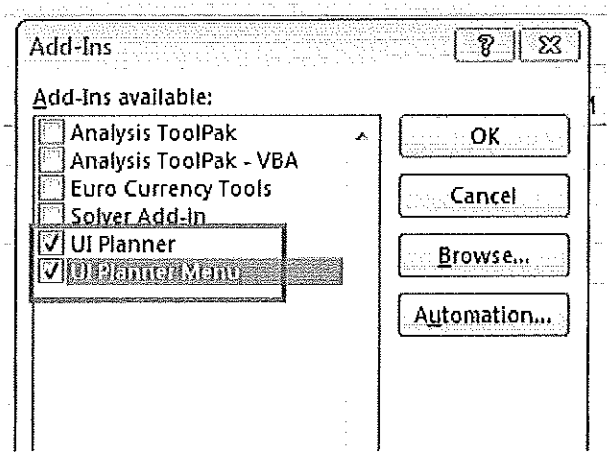
Excel Add-Ins – Step 3

Confirm the Add-In was installed

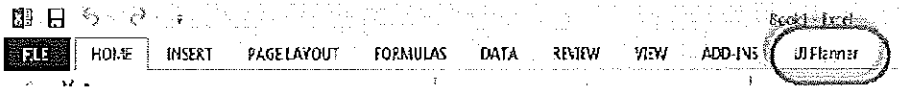
- ***For Excel 2003 or 2007***
  - Click 'Tools' menu
  - Select 'Add-Ins'
  - Confirm 'UI Planner' is checked



- ***For Excel 2010 or 2013***
  - Click File > Options > Add-Ins > GO
  - Confirm 2 UIPlanner Add-In files are checked



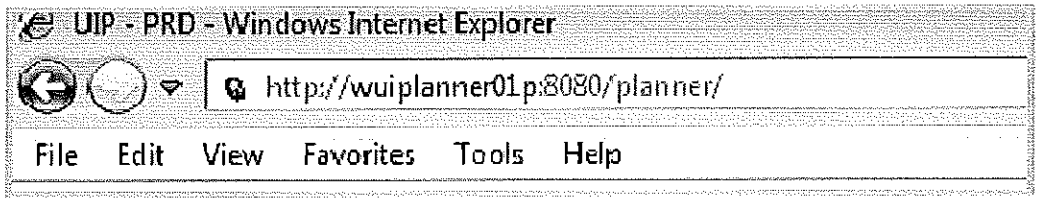
  - New 'UI Planner' Menu option appears

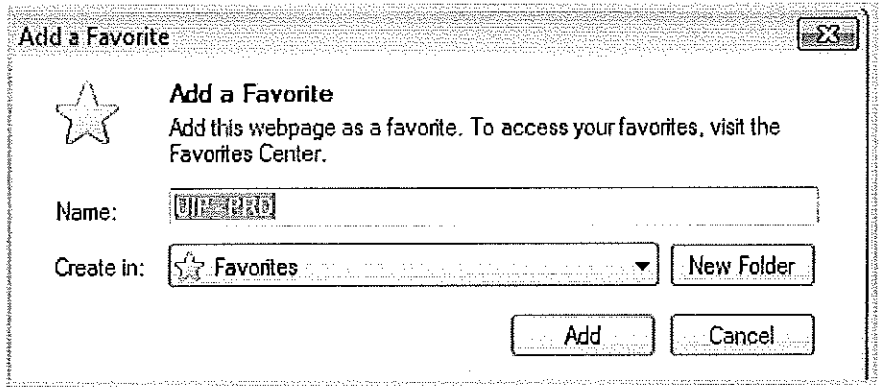


UIPlanner Log In

1. • Enter the link on the browser line
   - http://wuiplanner01d:8080/planner/ - Development
   - http://wuiplanner01t:8080/planner/ - Test
   - http://wuiplanner01p:8080/planner/ - Production

- Add to Favorites

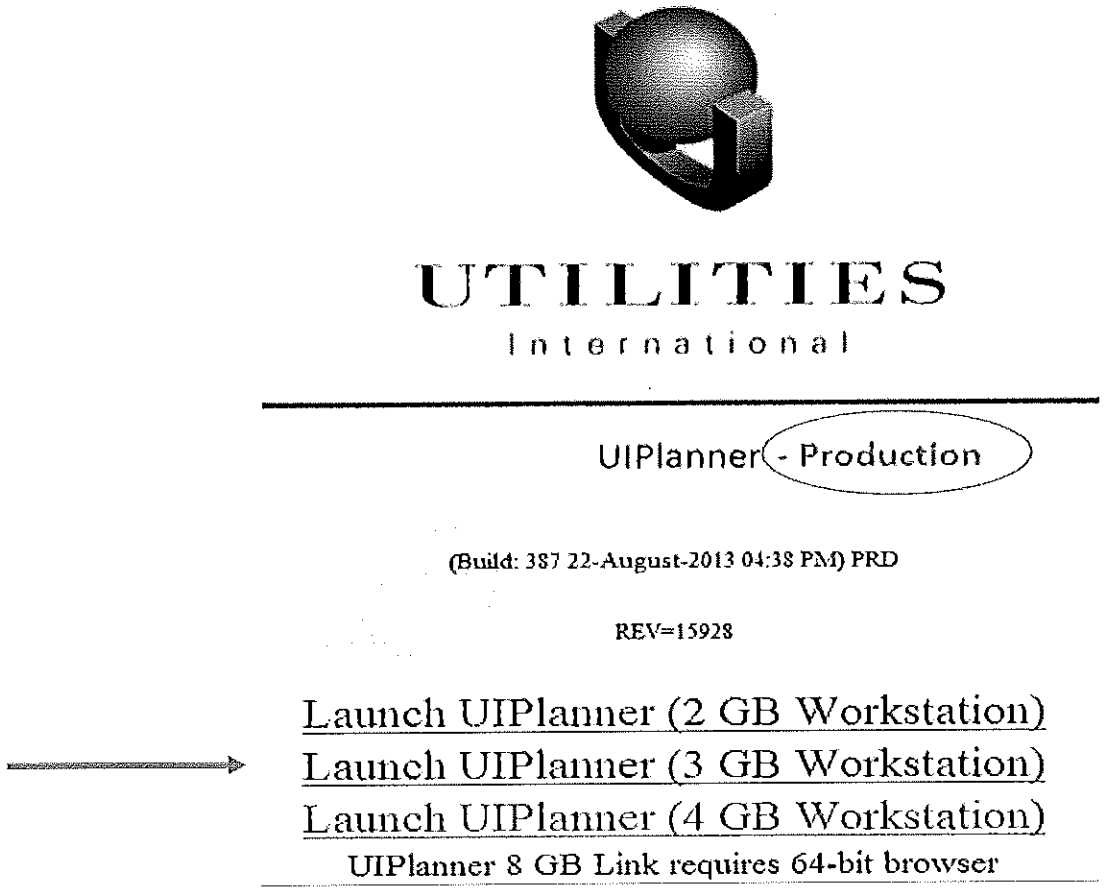




UIPlanner Log In

2

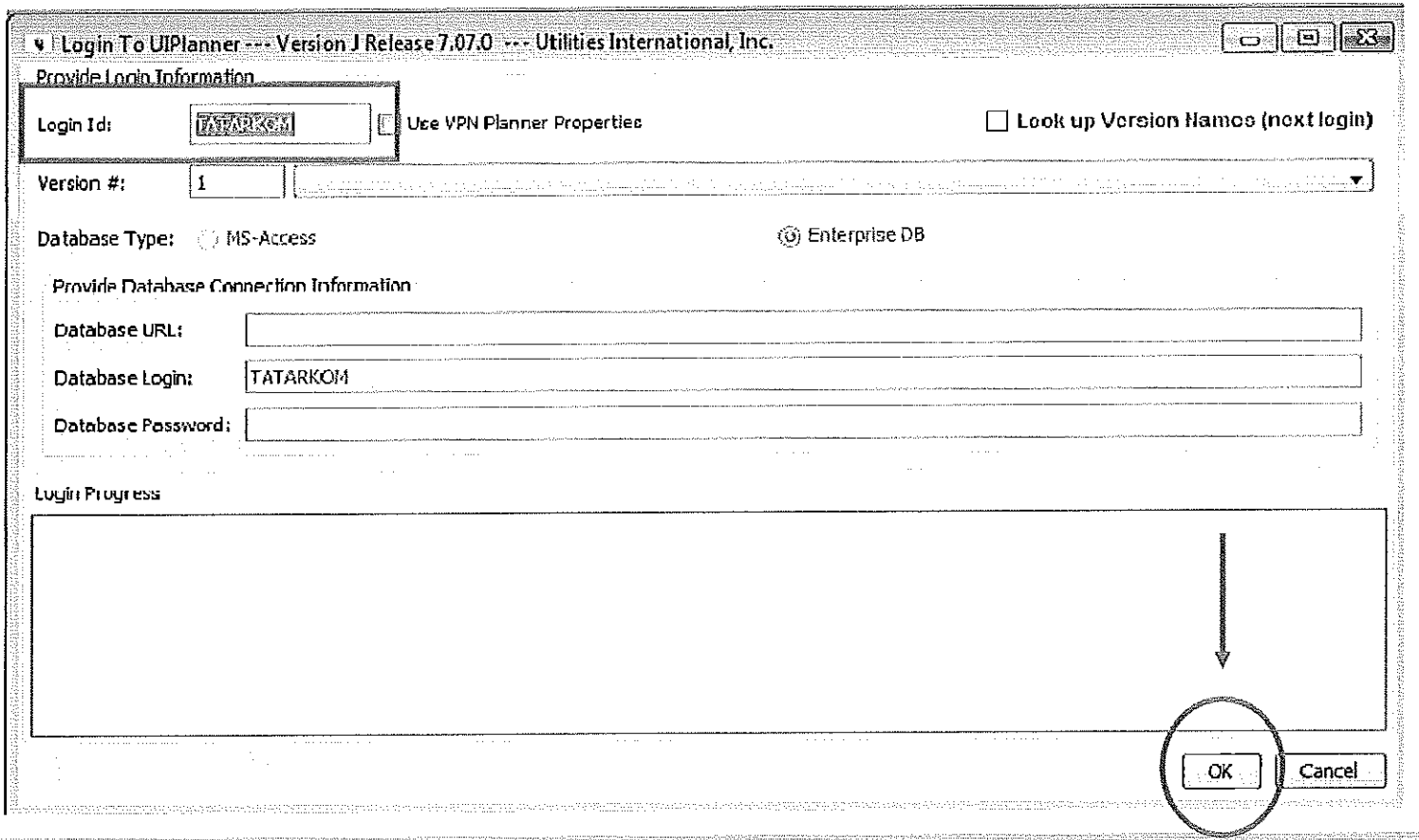
- After entering the link, the UIPlanner software main screen will display
- Click on (3 GB or 4 GB Workstation)



UIPlanner Log In

4

- User Login ID will display
  - UIPlanner has single sign on capability and authenticates on your network login ID
- Click OK



UIPlanner Security

UIPlanner Security

- UIPlanner security will be established using the Financial Accountability Model hierarchy (ZBWCAM0000) and granted at the node level within each business unit/department

- Multiple roles or levels of security will be granted

  - **Budget Security**
    - Controls access to Budget-specific features and data
    - Includes Application Rights, which control access to screens and tools, and Cost Center Rights which limit access to data based on the user's context within a "Center" hierarchy

  - **Model Security**
    - Controls access to create and delete system-wide model related objects (e.g. Entities, Attributes) and administrative tools (e.g. Manage Menus, Archive)

Key UIPlanner Security Roles

- **System Administrator:**
  - Centralized group that will manage and maintain both B2 and Financial Model
  - Individuals will have all rights to system and can perform functions the average user can not, such as: system configuration, bounce server, deploy new releases

- **Budget Administrator**
  - Centralized group that will manage and maintain B2 system
  - Individuals will have rights to system and can perform all system, business and process functions
    Examples include creating budget scenarios, running interfaces, process budget/forecast close, administer security, system admin locking, maintaining datasets, global assumptions, etc.

- **Budget Coordinator**
  - Individuals having rights to their entire business unit or department
  - Access to all user functions such as viewing and validating individual employee labor data, allocating labor and non labor, project planning, create budget group budget items, budget approval/center locking, and publish reports for their respective areas

- **Budget Input**
  - Individuals having rights to either their entire business unit or department or a specific group or center
  - Individuals will be granted access to all basic budget functions but will not be able to view individual employee labor data, create budget group budget items, and center lock

- **Budget View Only**
  - Individuals can only view published results and view reports

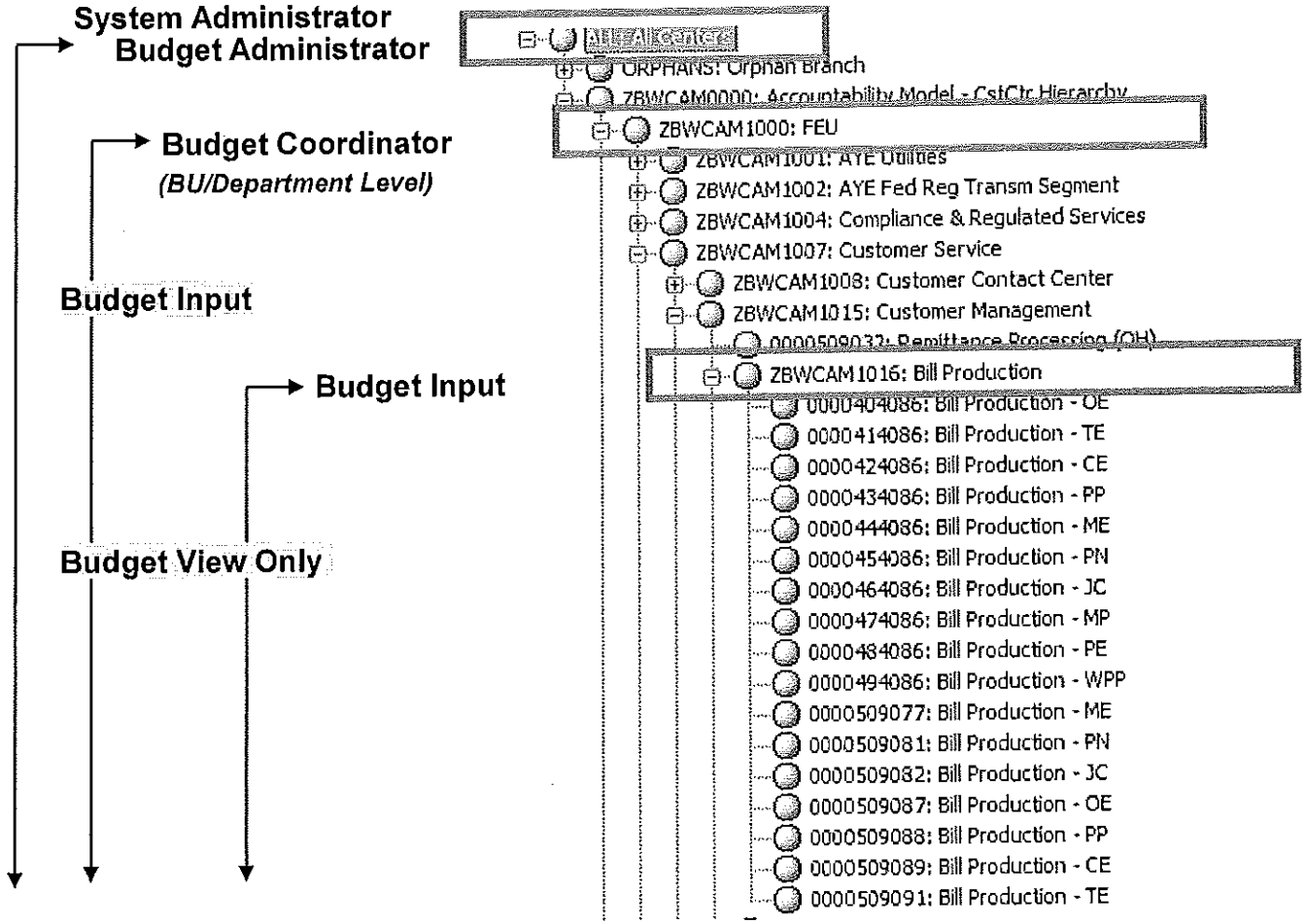
Key UIPlanner Security Roles

- **Budget Coordinator / Model Input**
  - Individuals responsible for both managing labor and other than labor functions for their area and has responsibility for key model inputs

- **Model Administrator**
  - Individuals having rights to the financial model and can perform all model functions

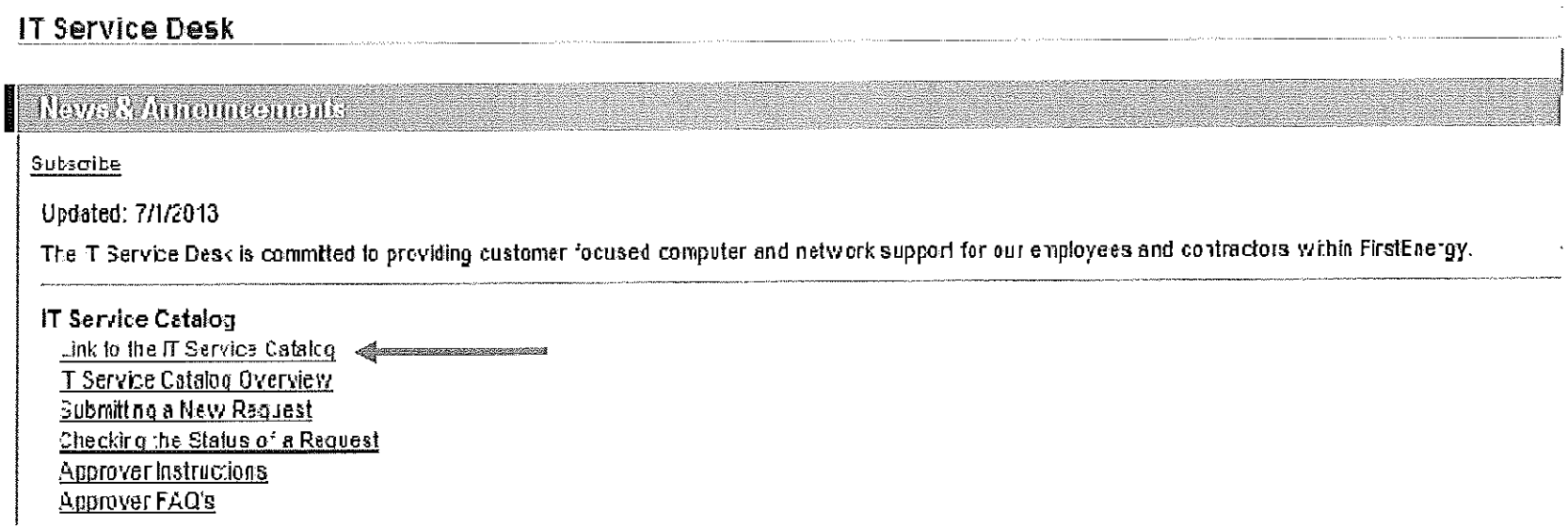
Cost Center Hierarchy and Security

- Budget Security will be established using the Financial Accountability Model hierarchy and granted at the node level within each business unit/department
- Multiple roles or levels of security will be granted



UIPlanner Security Requests

- **UIPlanner Security requests will be managed via the IT Service Catalog**
  - Security requests include: establishing new security, changing security, and removing security for either data collection or financial modeling
  - This process is used for both employees and contractors
- **The IT Service Catalog can be accessed in one of two ways via the portal:**
  1. Path: Services and Support>Work Related>IT Service Desk>Link to the IT Service Catalog
  2. IT Service Catalog can also be accessed by typing 'ITcatalog' into the Internet Explorer Address Bar



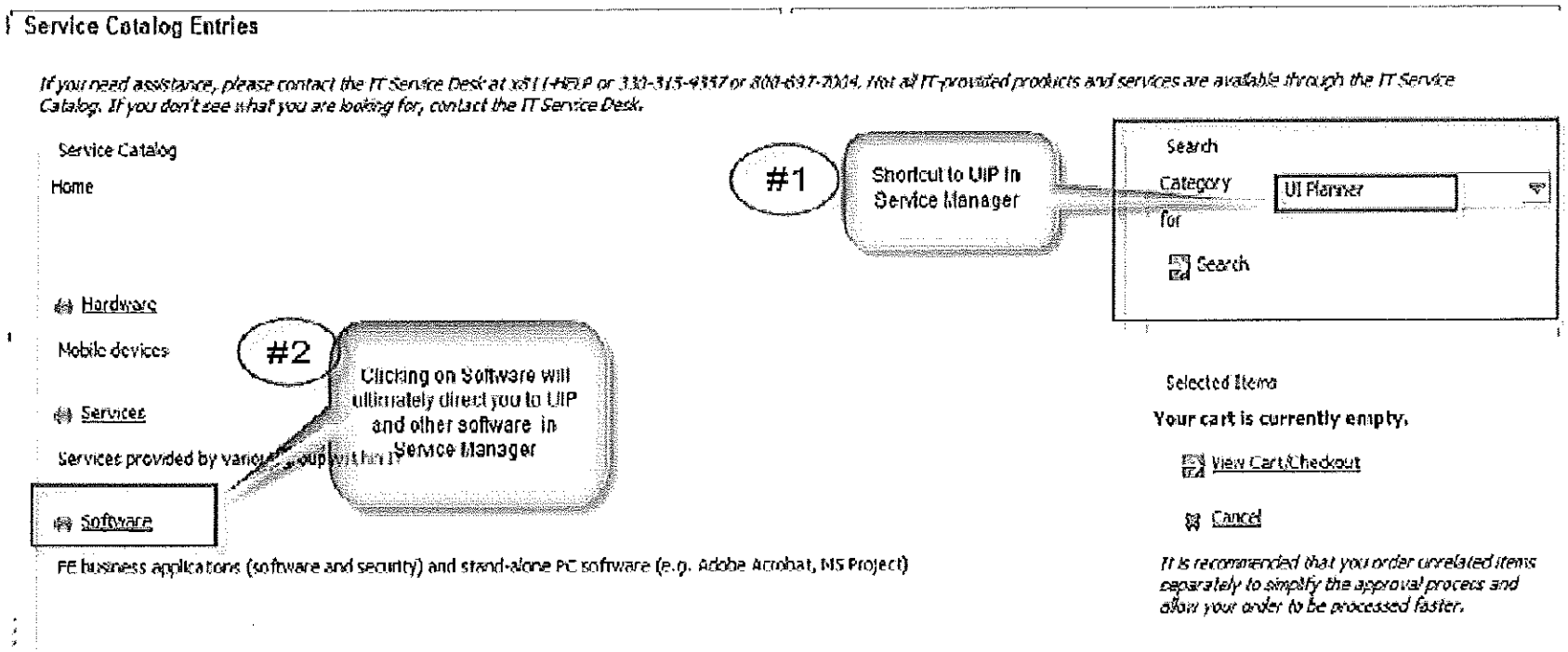
How to Request UIPlanner Security

- **To request UIPlanner security for data collection or financial modeling perform the following processes once in the IT Service Catalog:**
  - Search for UIPlanner by selecting "UIPlanner" in the Category field of the Search (see #1 below)

    OR

    Navigate to

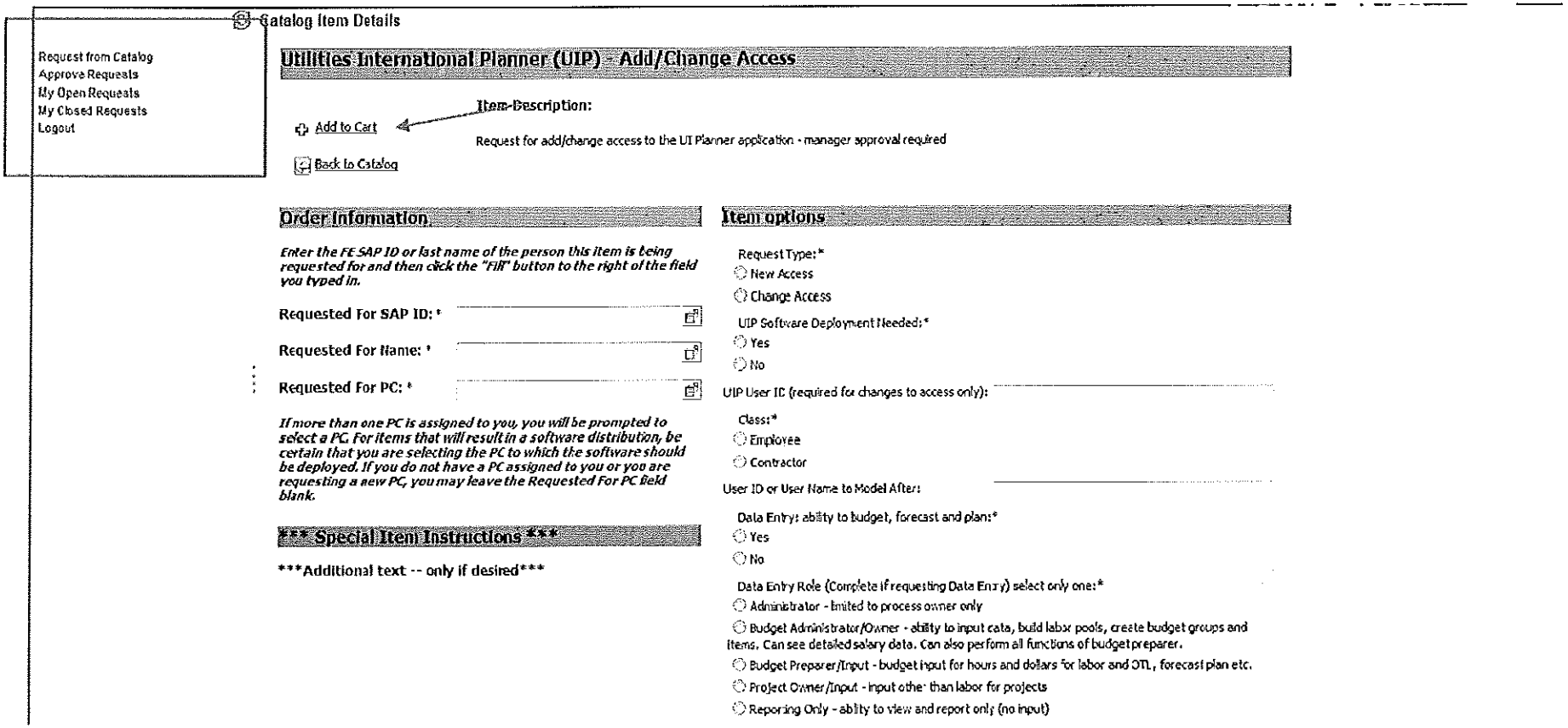
    Software>FE Business Applications>Corporate Business Applications>Finance Business Applications>UIPlanner
  - Select UIPlanner – Add/Change Access (see #2 below)
  - Follow instructions on form
  - For further information on UIPlanner security, refer to the UIPlanner Security Management Policy located at: Portal >Communities> Finance> Policies> FiT



Requesting or Changing User Security

After completing the form

1. Click "add to cart". A message box will appear that it has been added.
2. Click "view cart/checkout" when finished.
3. The request will be routed for approval.
4. To view the status of the request, follow the links on the left of the screen



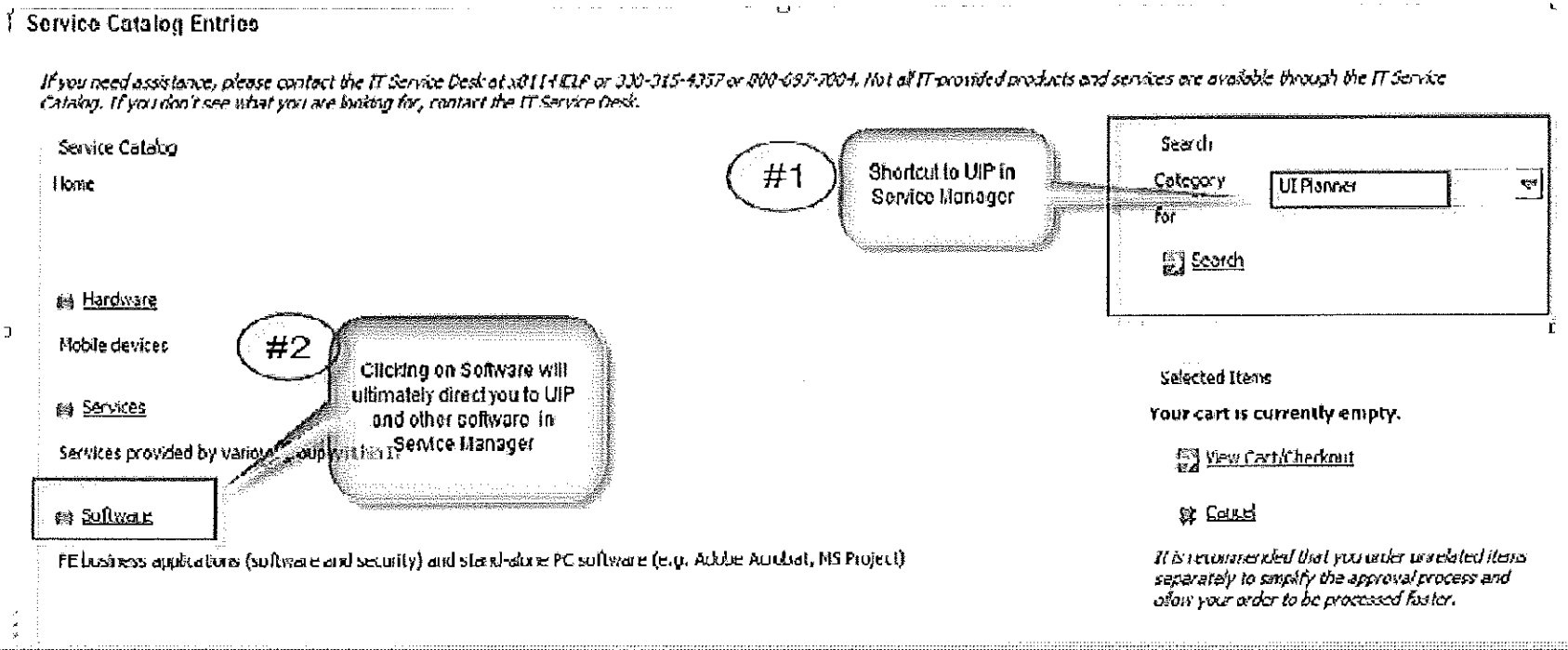
Removing UIPlanner Security

- **To Remove UIPlanner security for data entry and/or financial modeling perform the following process:**
  - Search for UIPlanner by selecting "UIPlanner" in the Category field of the Search (see #1 below)

    OR

    Navigate to

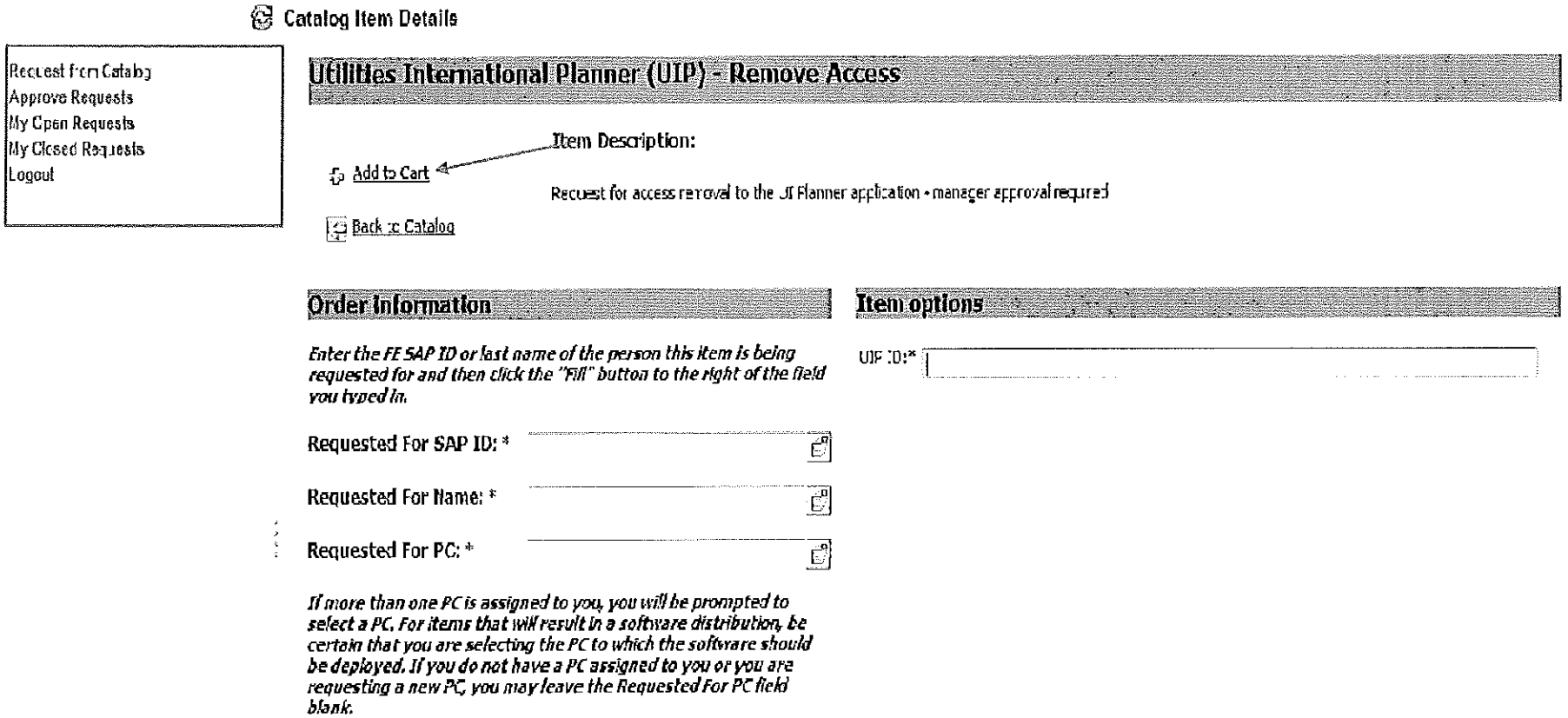
    Software>FE Business Applications>Corporate Business Applications>Finance Business Applications>UIPlanner (see #2 below)
  - Select UIPlanner – Remove Access
  - Follow instructions on form
  - For further information on UIPlanner security, refer to the UIPlanner Security Management Policy located at: Portal >Communities> Finance> Policies> FiT



Removing UIPlanner Security

After completing the form

1. Click "add to cart"
2. The request will be routed for approval.
3. To view the status of the request, follow the links on the left of the screen



Obtaining Help

- **IT Service Catalog help is available on the on the IT Service Desk Portal page as well as contacting the IT Service Desk**

IT Service Desk

News & Announcements

Subscribe

Updated: 7/1/2013

The IT Service Desk is committed to providing customer focused computer and network support for our employees and contractors within FirstEnergy.

New USB Removable Device Policy

Please go to the Cyber Security Policies page to review the new policy listed as IT-SEC-POL-013 Computer and Network Usage - 08.15.13.

USB Removable Media Device Restrictions FAQs

IT Service Catalog
- Link to the IT Service Catalog
- IT Service Catalog Overview
- Submitting a New Request
- Checking the Status of a Request
- Approver Instructions
- Approver FAQ's

Contact the IT Service Desk by phone for immediate assistance, or send an email to FE Help Desk and your request will be addressed as quickly as

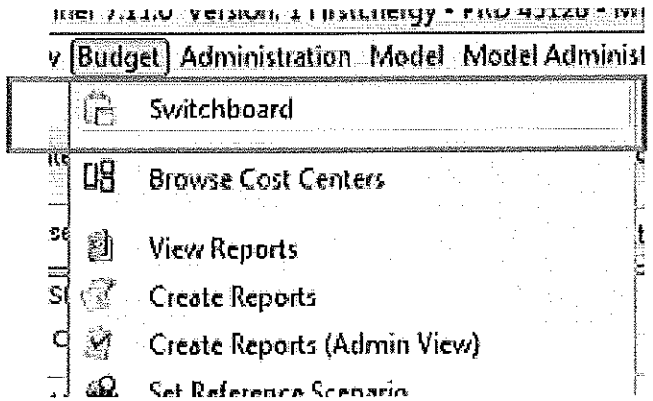
Internal	External	FAX
811-HELP 811-4357	330-315-4357 800-697-7004	801-6867 330-374-6867

- **For more information on requesting access refer to policies on the portal at: Communities > Finance > Polices & Procedures > FiT**
  - **UIPlanner – Security Management**

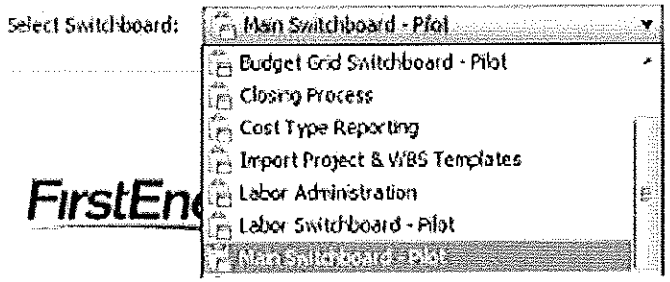
Navigating in UIPlanner — Browse Cost Center

Navigating in UIPlanner

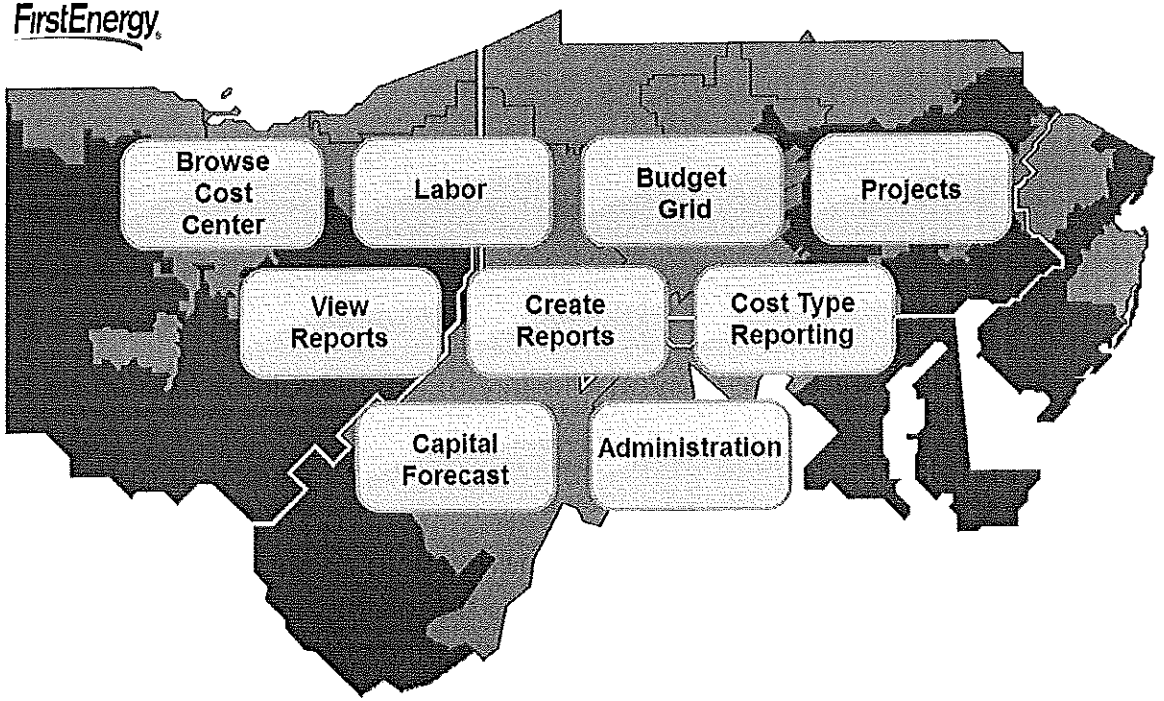
1. • Select Budget
   • Click Switchboard



2. • Select Main Switchboard-Pilot



- Switchboards allow users to visually navigate through various screens
- User can map processes and features to a diagram created in Power Point or Visio
- Hot-spotted areas on a switchboard can open menu items, run reports, open files, and open other switchboards
- Switchboards will be maintained by the System Administrator

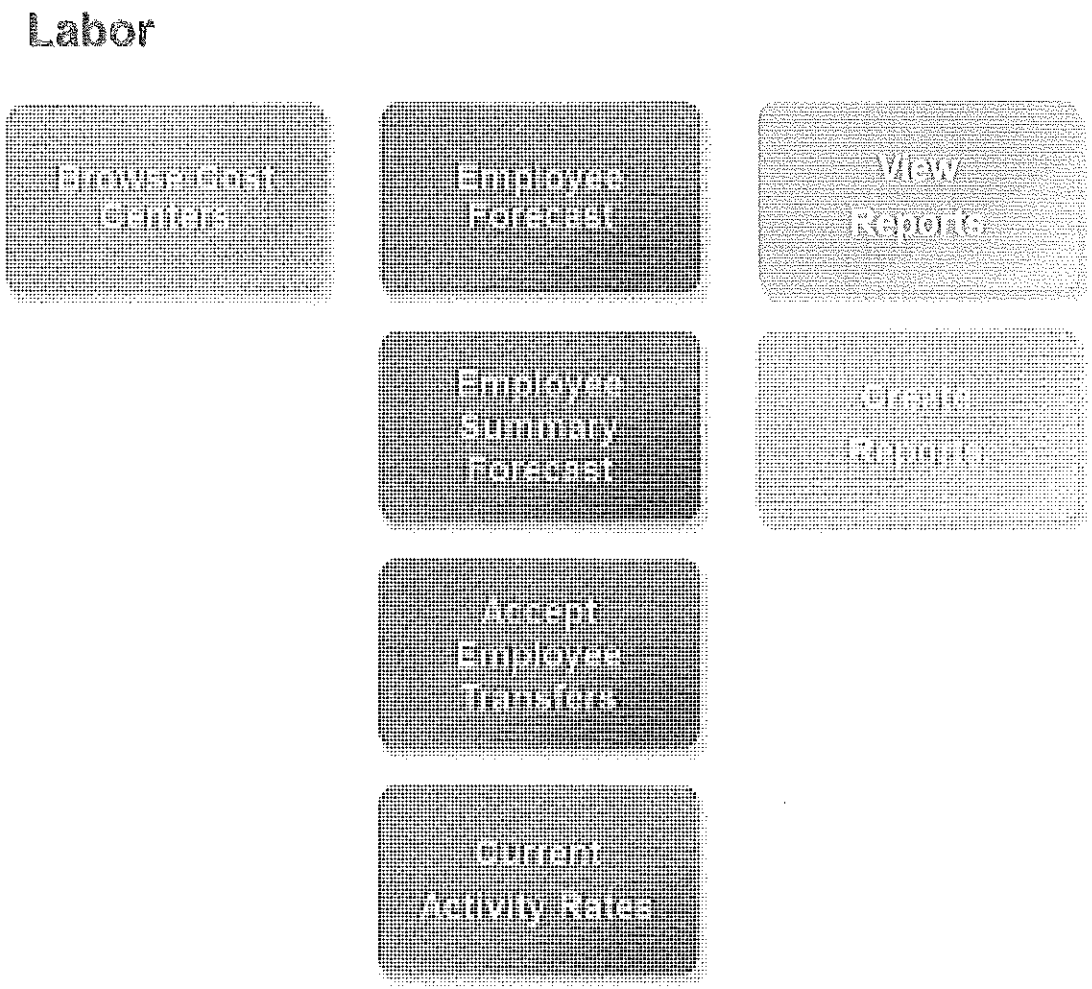


Navigating in UIPlanner

Secondary switchboards exist for the following screens/activities:

- Labor
- Budget Grid
- Projects
- Import Projects
- Cost Type Reporting
- Capital Forecast
- Administration
- Labor Administration

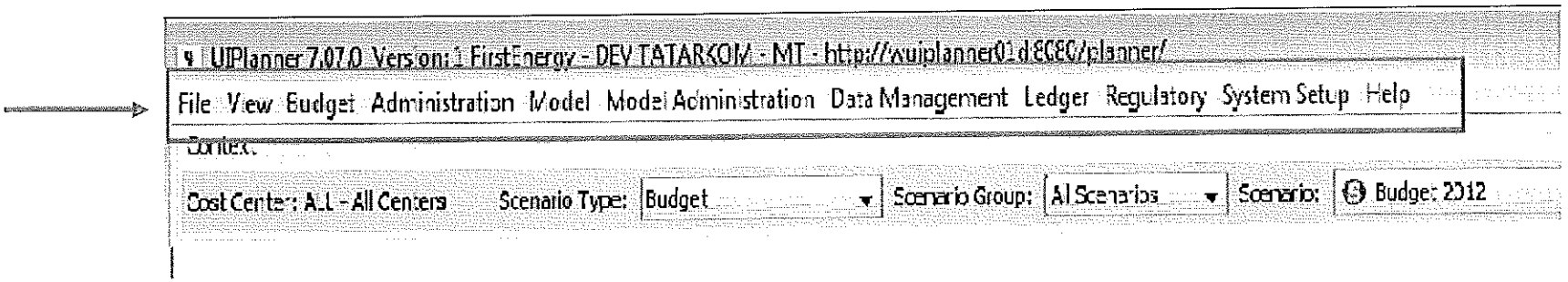
Example of Labor switchboard:



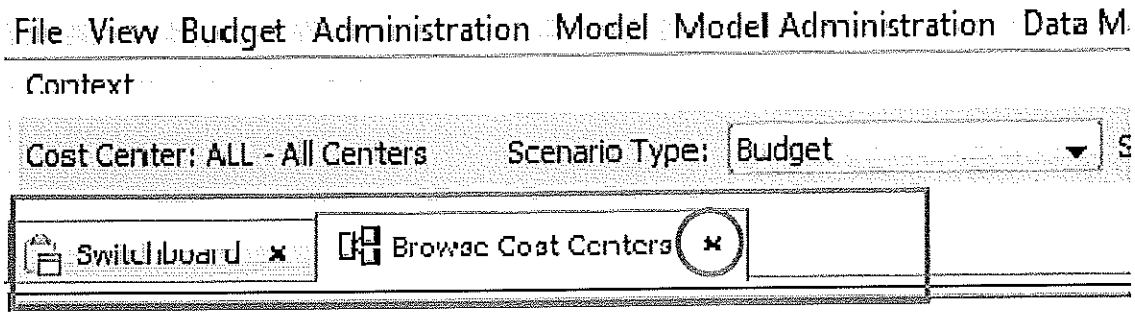
Navigating In UIPlanner

3

- Once logged into UIPlanner, menu options will appear across the screen
- Depending on your security, certain menu items may not be available



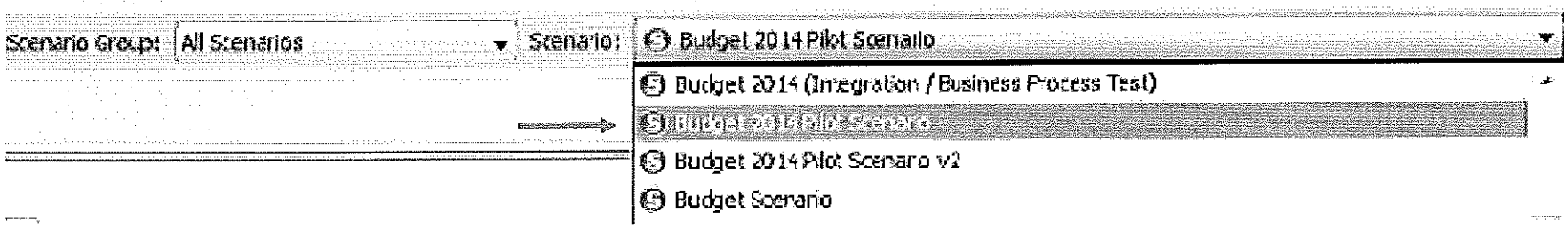
- As menu items are opened, the tab for each menu item will stack across the screen
- Menu items can be closed by clicking the X



Navigating in UIPlanner

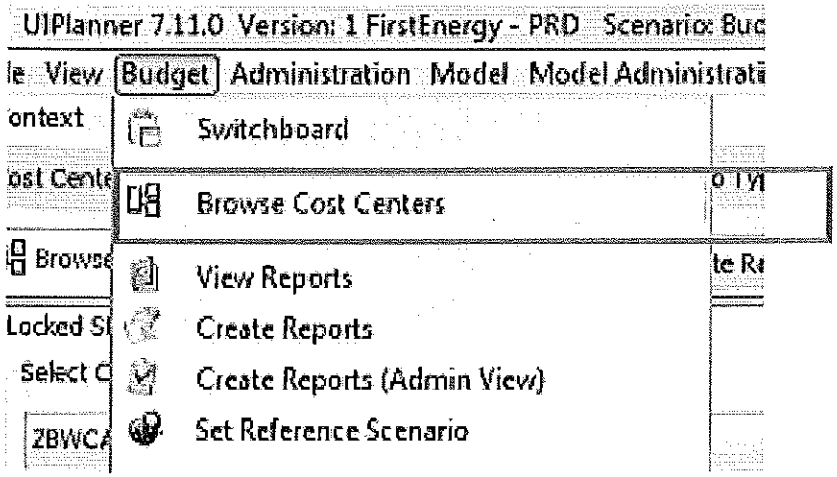
4

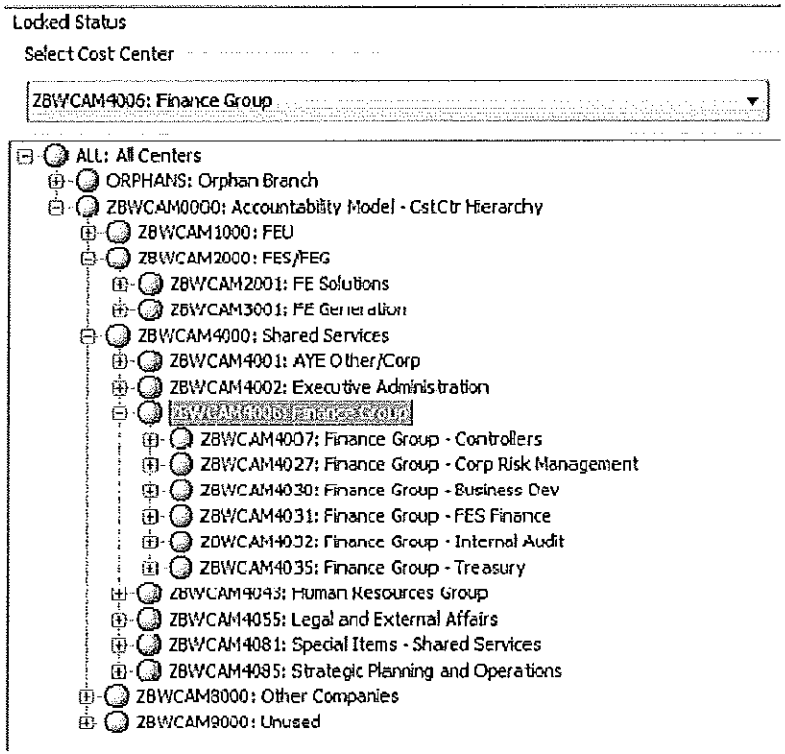
- UIPlanner categories determine the environment to administer the budget, forecast and plan
  - Cost Center: Displays the Cost Center or Cost Center group level selected
  - Scenario Type: Budget or Model
    - Select Budget
  - Scenario Group: Grouping of like scenarios for either Budget or Model
    - Select All Scenarios
  - Scenario: Various iterations and versions of the budget, forecast and plan such as the 3+9, 2013 annual budget, etc. Scenarios will be available within the Scenario drop down box. Scenarios will be created and managed in B2
    - Select Budget 2014 Pilot Scenario



Browse Cost Center Overview

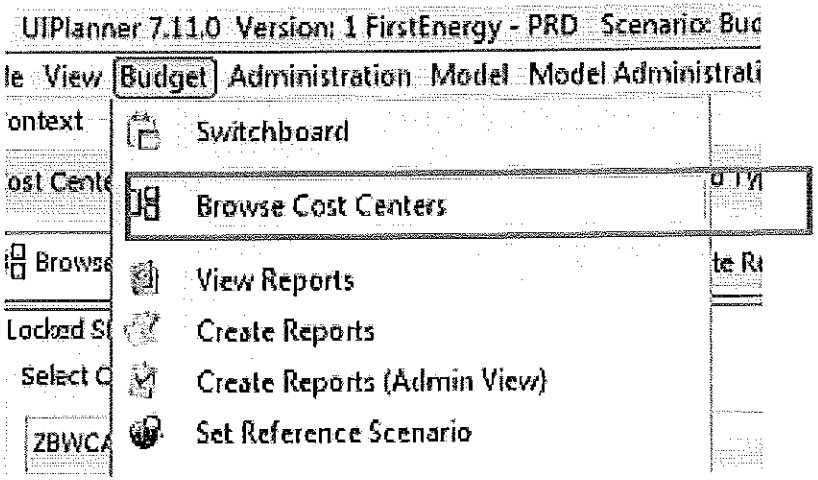
- The Browse Cost Centers function is used throughout UIPlanner to view data for budget, forecast and plan activities
- The Select Center screen is used to select a cost center or department, manage status and monitor changes within UIPlanner
- The Cost Center or Cost Center node selected is carried forward as a filter on department to all budget screens





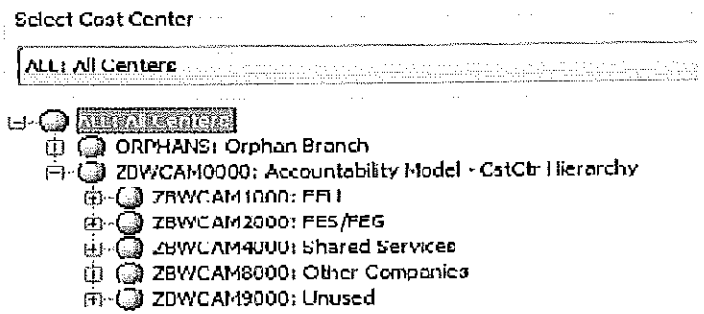
Browse Cost Center

5 • Select **Budget**
• Click **Browse Cost Centers**

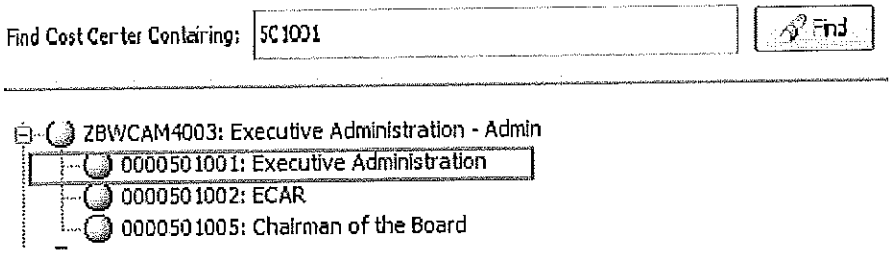


- The Finanical Accountability Model hierarchy is available in UIPlanner and SAP
  - SAP transaction KSH3 – ZBWCAM0000
- Hierarchy is based on cost ownership
- The responsible cost center hierarchy will no longer be available starting 2014

6 • Expand Hierarchy by clicking ⊕

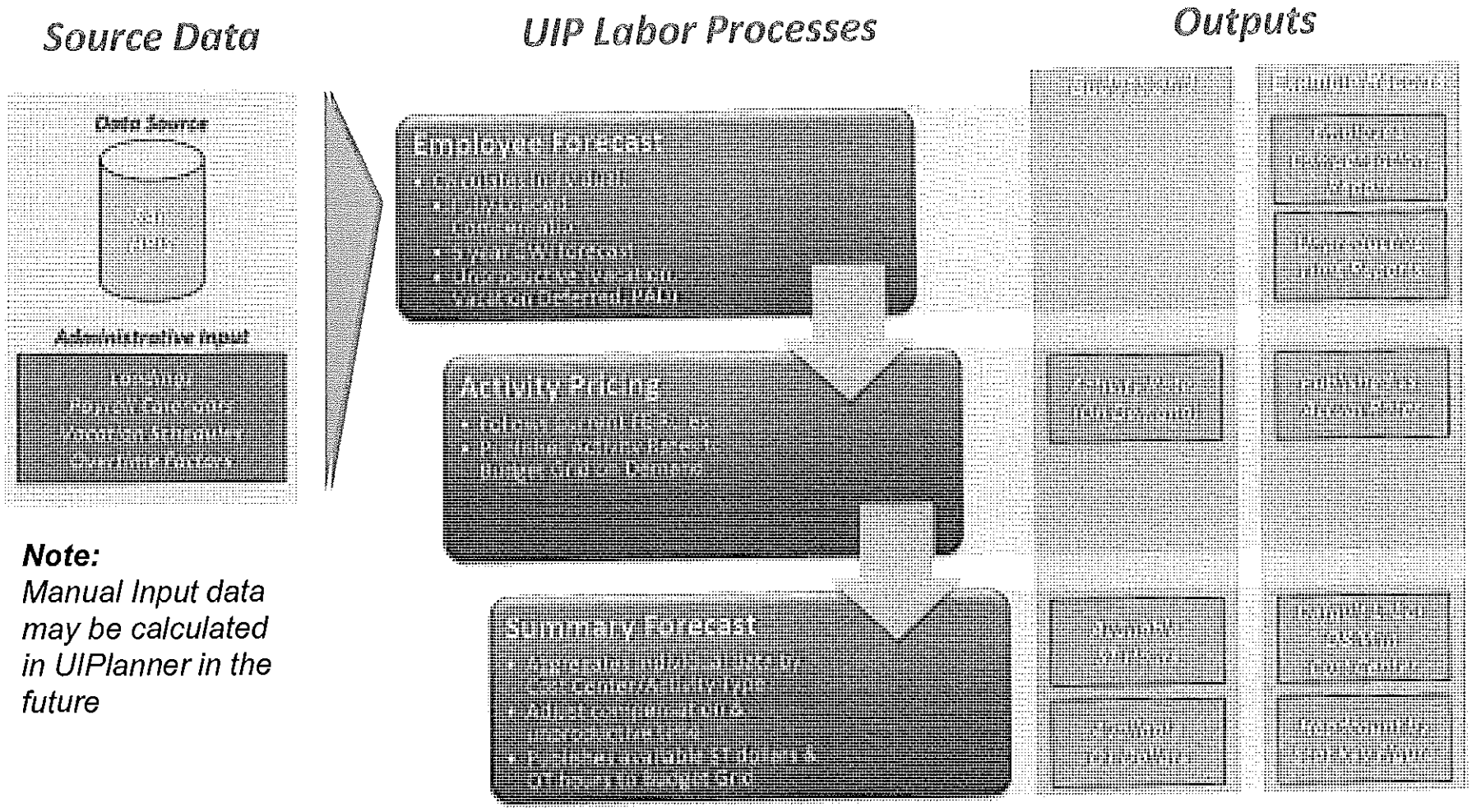


7 • Search Cost Centers in the Hierarchy
• Enter Cost Center or Cost Center description and Click **Find**



Labor Overview

UIPlanner Labor Schematic



Note:
Manual Input data may be calculated in UIPlanner in the future

The new Labor process ensures that activity rates will be available prior to the budget process while enhancing data security and transparency

System Entry - Budget Grid Functions

Budget Grid Overview

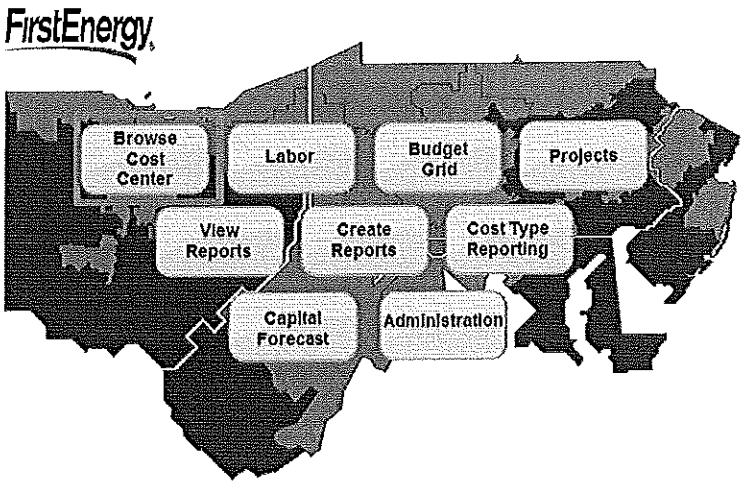
- The Budget Grid is where users enter their Labor and Other-Than-Labor (OTL) budget, forecast, and plan data by the various cost collectors.
- Used only for ALLOCATING hours and dollars --- use "View Reports" to see complete Cost Center view
- Specific budget grid fields comprise the code block combinations necessary to validate system entry

Budget Grid Data Fields

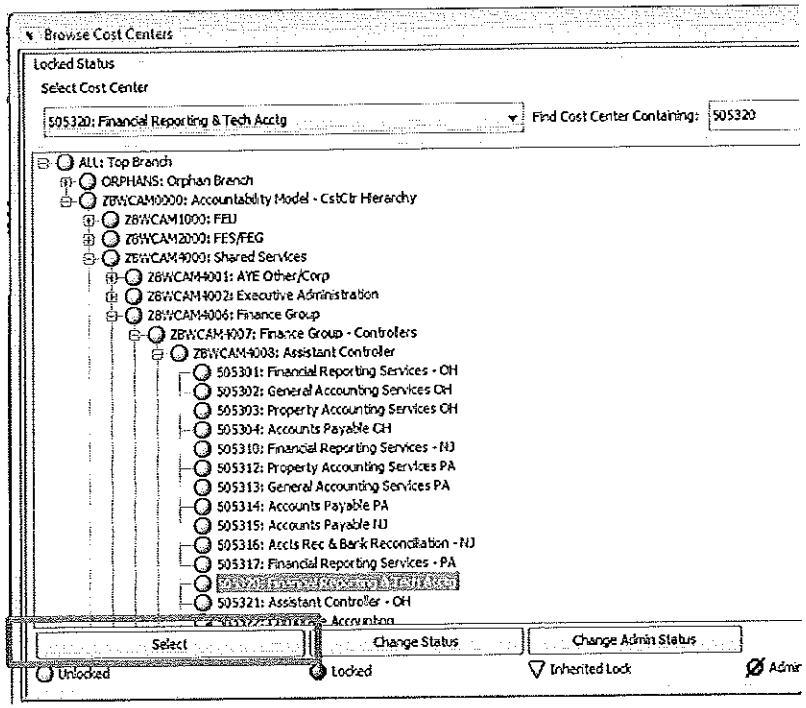
Field	Input vs. Derived	Notes
Cost Source	Input	Cost Source is the Cost Center where employee labor resides. Available Cost Centers will be limited based on user security
Cost Owner	Input	Cost collector owner. When budgeting Labor, this will be the Cost Center being billed for the Labor. When budgeting OTL, Cost Owner and Cost Source will be the same
Cost Collector Type	Input	Types : Cost Center, Internal Orders and WBS
Planning Project	Input	Project Definition of either SAP WBS or the UI Planning Project being budgeted
Planning WBS Element	Input	SAP WBS Elements or the UI Planning Project Elements
Internal Order	Input	Valid and budgetable internal orders
Activity Type	Input	Required only for Labor. Should be set to 'OTL' when budgeting OTL.
Cost Element	Input	Valid and budgetable cost elements
Budget Group	Input	Allows user to apply more detail to the budget. Budget Groups might include Travel or Office Supplies
Budget Item	Input	Allows user to apply more detail to the budget. Budget Items might include Airfare, Hotel and Meals for the Budget Group of Travel.
Comment	Input	Text field. Used for additional notes
Input Type	Derived	Hours if Labor and Dollars if OTL

Budget Grid Startup

1. Defining a Context Cost Center
   - Open the **FE Main Switchboard**
   - Click on **Browse Cost Center**

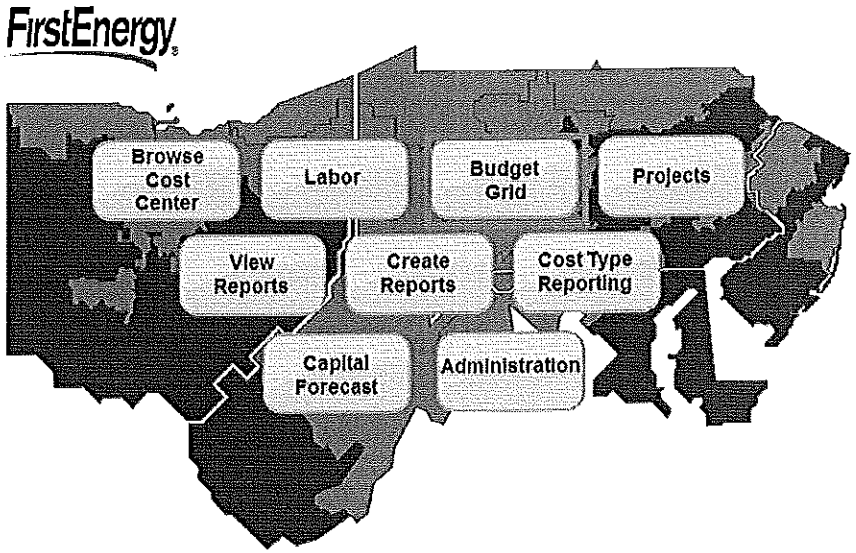


2. • Select a Cost Center (either double-click on or highlight a Cost Center and click the **Select** button at the bottom of screen)

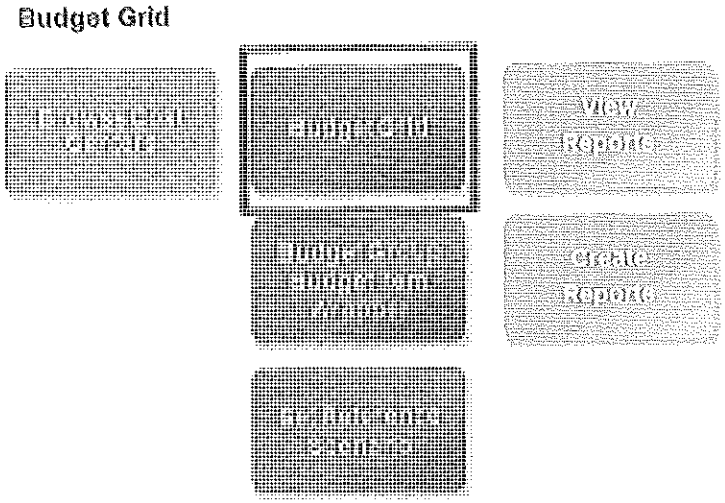


3 Opening the Budget Grid

- Open the **FE Main Switchboard**
- Click on **Budget Grid**

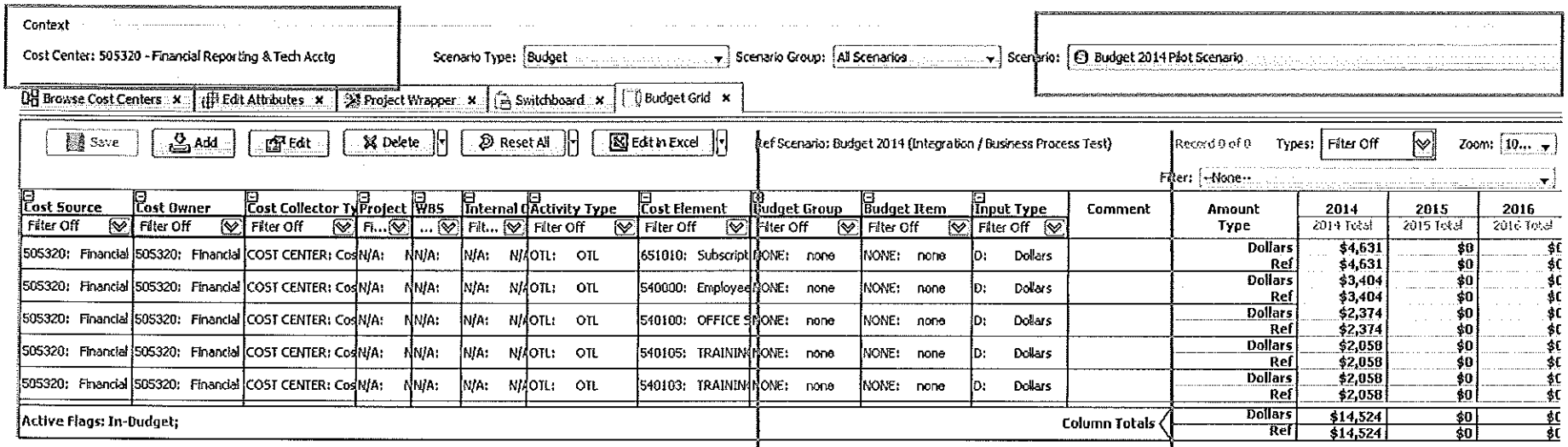


4 • Click **Budget Grid**



Budget Grid Layout Overview

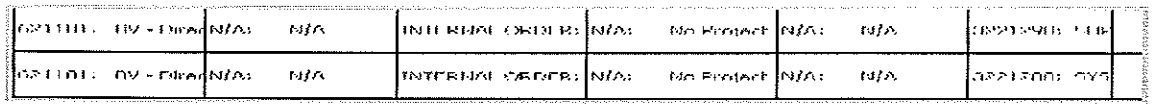
- The Budget Grid consists of required and optional entries
- User can customize grid and maintain user preferences
- Attributes are listed on the left hand side (Accounting) of the Grid
- Data entry takes place on the right hand side of the Grid



Codeblock combinations align with SAP actuals

User defined fields to facilitate budget, forecast, plan preparation and approvals

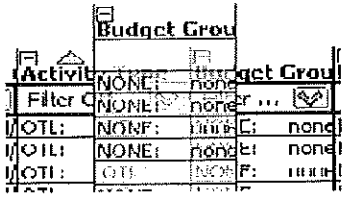
Rows displayed in red denote invalid combinations. Would occur if system validations were changed. User will not be able to enter invalid codeblock

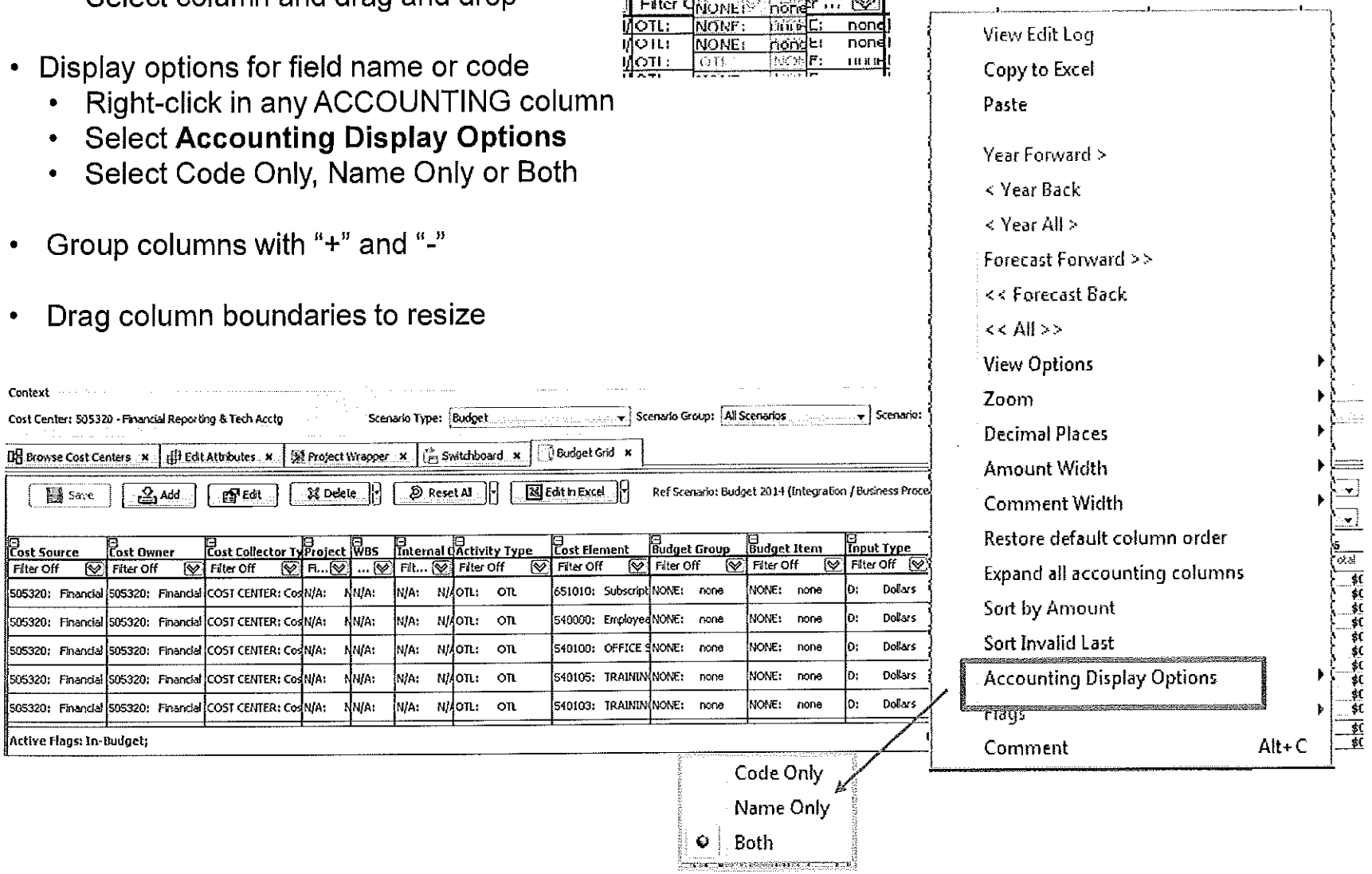


Budget Grid Functions - Display Options

5

- Column ordering
  - Select column and drag and drop
- Display options for field name or code
  - Right-click in any ACCOUNTING column
  - Select **Accounting Display Options**
  - Select Code Only, Name Only or Both
- Group columns with "+" and "-"
- Drag column boundaries to resize

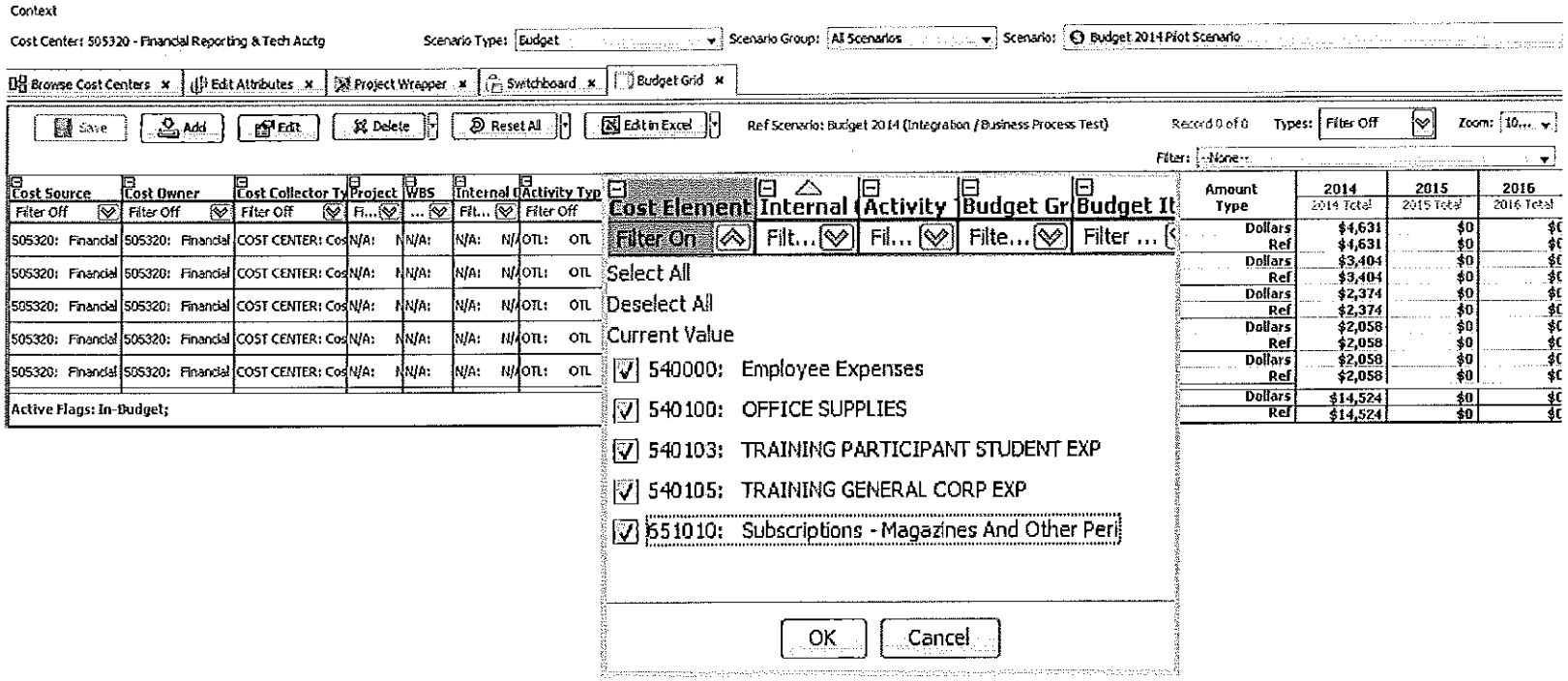




Budget Grid Functions - Filters

6

- Column filtering (e.g. cost element, activity type, etc)
  - All columns have filtering available
  - Select a column to filter
  - Click on filter (column heading turns red when filter is on)
  - Drop down available to select options



Budget Grid Functions - Data Display

- Monthly or annual view of data
  - Click on the year header to toggle between monthly and annual data

Context

Cost Center: 505320 - Financial Reporting & Tech Acctg Scenario Type: Budget Scenario Group: All Scenarios Scenario: Budget 2014 Pilot Scenario

Browse Cost Centers | Edit Attributes | Project Wrapper | Switchboard | Budget Grid

Save | Add | Edit | Delete | Reset All | Edit in Excel Ref Scenario: Budget 2014 (Integration / Business Process Test) Record 0 of 0 Types: Filter Off Zoom: 10... Filter: --None--

Cost Source	Cost Owner	Cost Collector Ty	Project	WBS	Inte	Comment	Amount Type	2014 2014 Total	2015 2015 Total	2016 2016 Total	2017 2017 Total	2018 2018 Total
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$4,631	$0	$0	$0	$0
							Ref	$4,631	$0	$0	$0	$0
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$3,404	$0	$0	$0	$0
							Ref	$3,404	$0	$0	$0	$0
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$2,374	$0	$0	$0	$0
							Ref	$2,374	$0	$0	$0	$0
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$2,058	$0	$0	$0	$0
							Ref	$2,058	$0	$0	$0	$0
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$2,058	$0	$0	$0	$0
							Ref	$2,058	$0	$0	$0	$0
Active Flags: In-Budget;						Column Totals	Dollars	$14,524	$0	$0	$0	$0
							Ref	$14,524	$0	$0	$0	$0

Context

Cost Center: 505320 - Financial Reporting & Tech Acctg Scenario Type: Budget Scenario Group: All Scenarios Scenario: Budget 2014 Pilot Scenario

Browse Cost Centers | Edit Attributes | Project Wrapper | Switchboard | Budget Grid

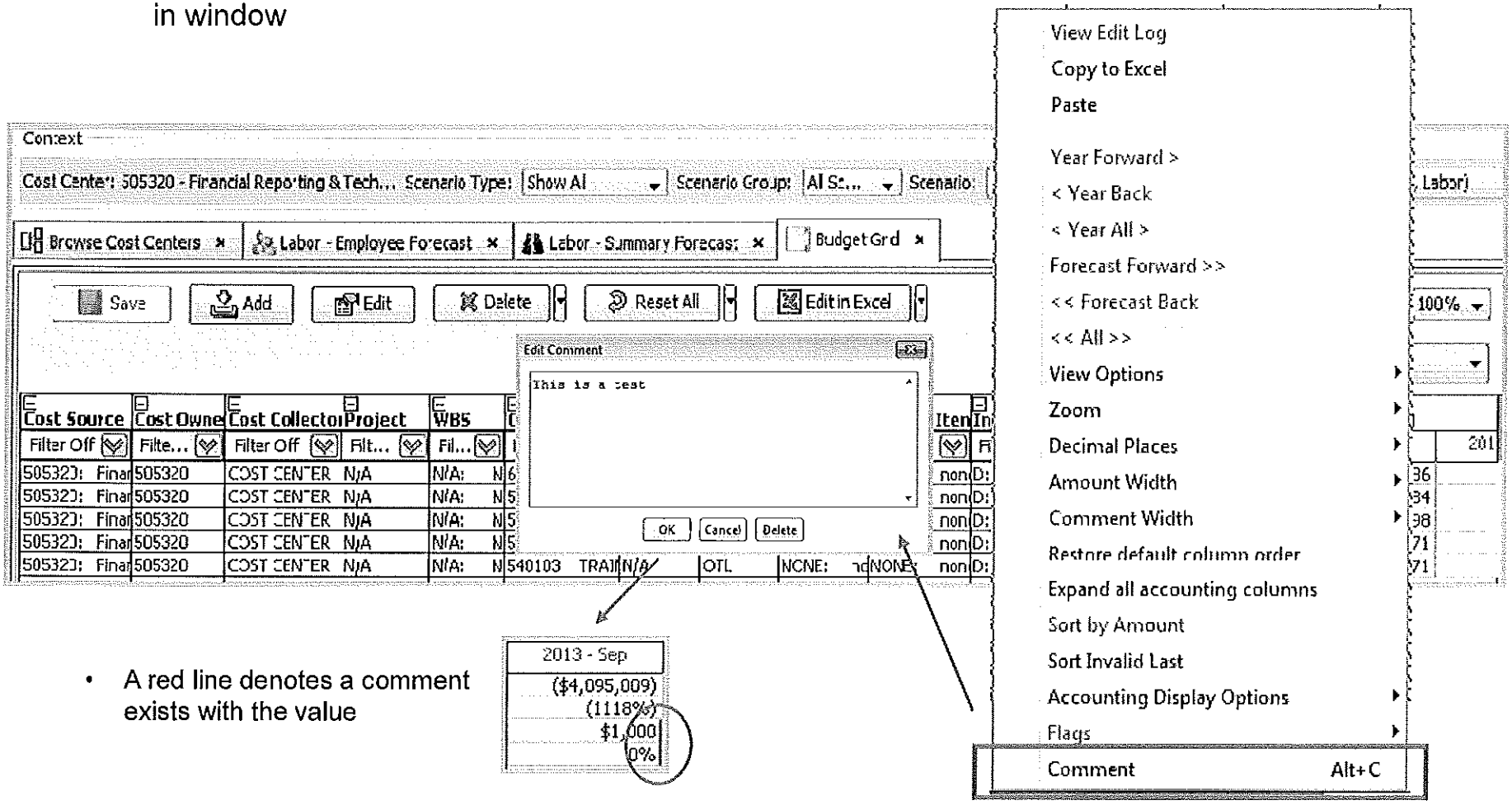
Save | Add | Edit | Delete | Reset All | Edit in Excel Ref Scenario: Budget 2014 (Integration / Business Process Test) Record 0 of 0 Types: Filter Off Zoom: 10... Filter: --None--

Cost Source	Cost Owner	Cost Collector Ty	Project	WBS	Inte	Comment	Amount Type	2014							
								2014 - Jan	2014 - Feb	2014 - Mar	2014 - Apr	2014 - May	2014 - Jun	2014 - Jul	2014 - Aug
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$386	$386	$386	$386	$386	$386	$386	$386
							Ref	$386	$386	$386	$386	$386	$386	$386	$386
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$284	$284	$284	$284	$284	$284	$284	$284
							Ref	$284	$284	$284	$284	$284	$284	$284	$284
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$198	$198	$198	$198	$198	$198	$198	$198
							Ref	$198	$198	$198	$198	$198	$198	$198	$198
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$171	$171	$171	$171	$171	$171	$171	$171
							Ref	$171	$171	$171	$171	$171	$171	$171	$171
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$171	$171	$171	$171	$171	$171	$171	$171
							Ref	$171	$171	$171	$171	$171	$171	$171	$171
Active Flags: In-Budget;						Column Totals	Dollars	$1,210	$1,210	$1,210	$1,210	$1,210	$1,210	$1,210	$1,210
							Ref	$1,210	$1,210	$1,210	$1,210	$1,210	$1,210	$1,210	$1,210

Budget Grid Functions - Comments

8

- Comment fields available on both grid and dollar/hour values
  - Right-click on the row you want to enter a Comment
  - Select Comment column and enter comment in window
  - Right-click on the actual dollar value and enter comment in window



- A red line denotes a comment exists with the value

Budget Grid Functions - Data Entry

9

- Enter values in data fields
- Change column or row level totals with automatic spread – annual or monthly
- Enter new column total for 2014 and press Enter
- Dollars spread proportionate to previous spread

Amount Type	2014 2014 Total
Dollars	$2,058
Dollars	$3,404
Dollars	$2,374
Dollars	$2,058
Dollars	$4,631
Dollars	$14,524

Existing total

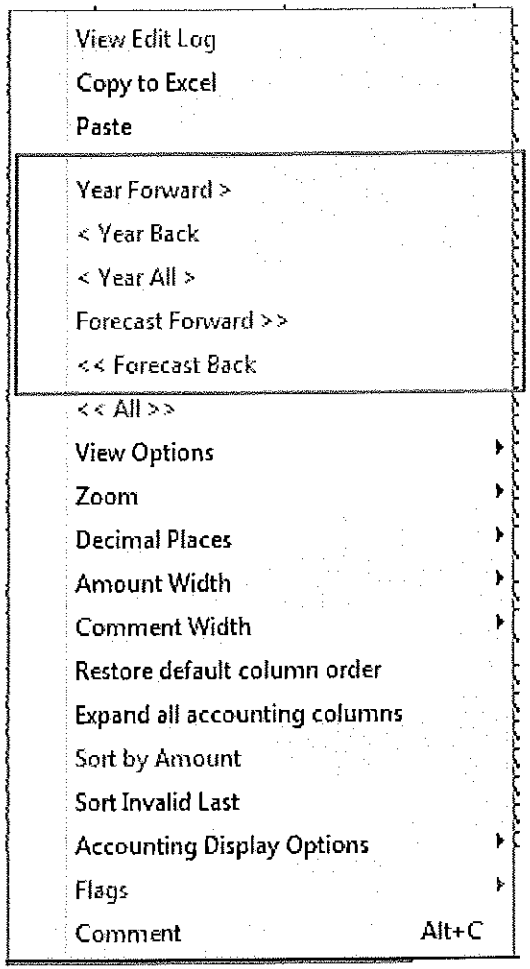
Amount Type	2014 2014 Total
Dollars	$14,166
Dollars	$23,439
Dollars	$16,347
Dollars	$14,166
Dollars	$31,882
Dollars	$100,000

Enter new total

Privileged & Confidential

Budget Grid Functions - Forecasting Options

- Year Forward - Year Back
  - Year Forward - Copy value from one month to remaining months in year
  - Forecast Forward - Copy value in current year to outer year

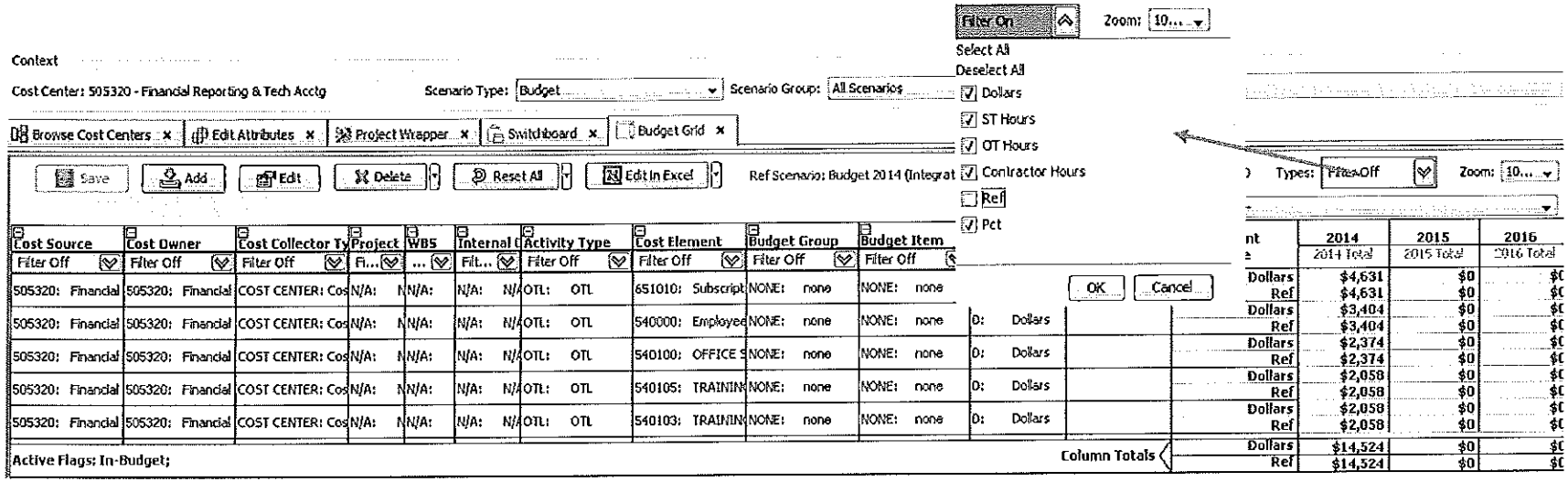


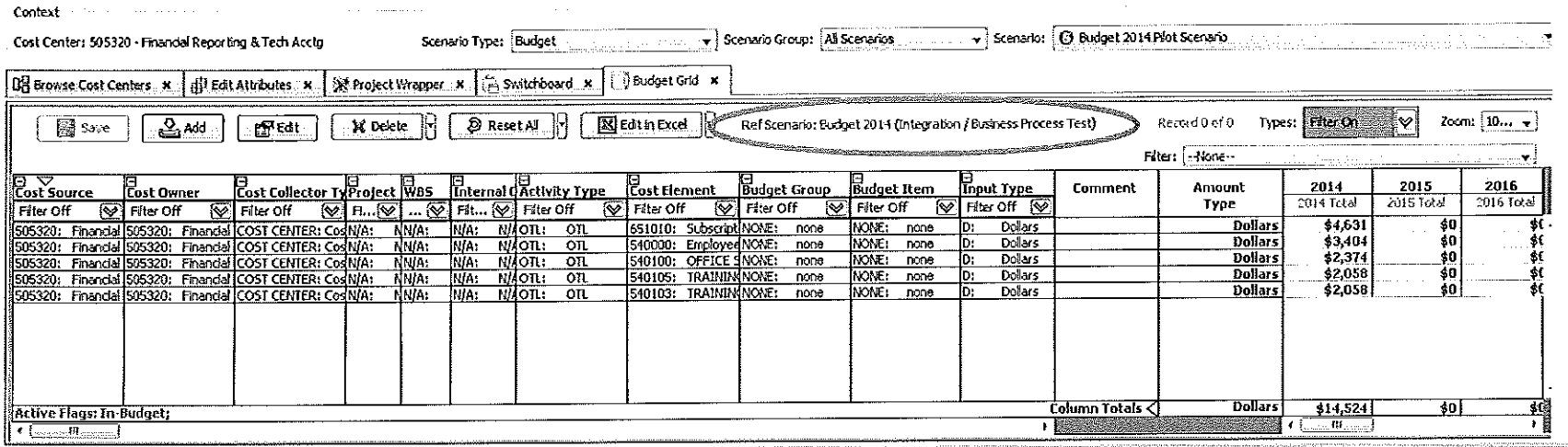
2013	2014				
2013 Total	2014 - Jan	2014 - Feb	2014 - Mar	2014 - Apr	2014 - May
$4,631	$100	$100	$100	$100	$100
$3,404	$0	$0	$0	$0	$0
$2,374	$0	$0	$0	$0	$0
$2,058	$0	$0	$0	$0	$0
$2,058	$0	$0	$0	$0	$0

Dollar value copies to remaining months

Budget Grid Functions - Reference Scenario

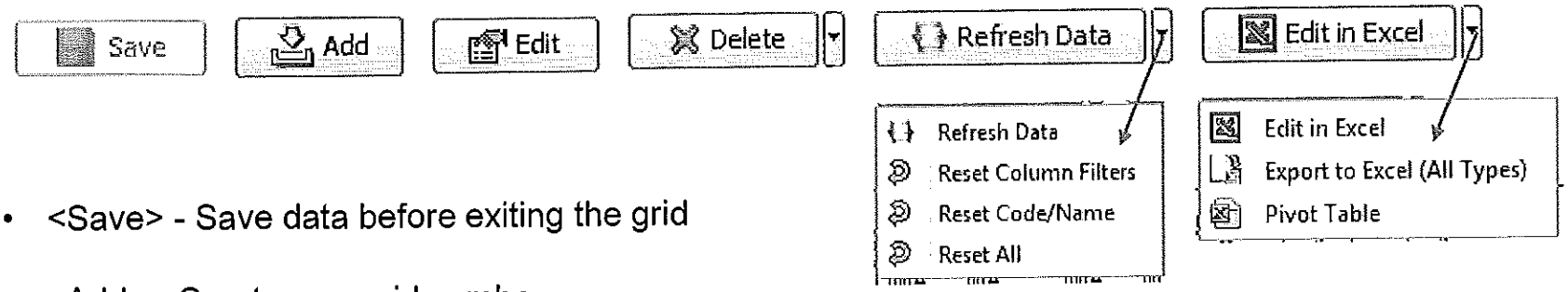
- UIP Grid allows for direct comparisons between scenarios (called "Reference Scenarios")
- Reference Scenarios are set by System Administrator
- Toggle by clicking on "Type" filter and selecting/deselecting "Ref"





12

- Basic Functions



- <Save> - Save data before exiting the grid
- <Add> - Create new grid combo
- <Edit> - Change a cost collector combo
- <Delete> - Remove a cost collector combo
- <Refresh Data> - Update grid with most recent changes/data
- <Reset Column Filters>
- <Reset Code/Name>
- <Reset All>

  } - Restores accounting data columns to original settings

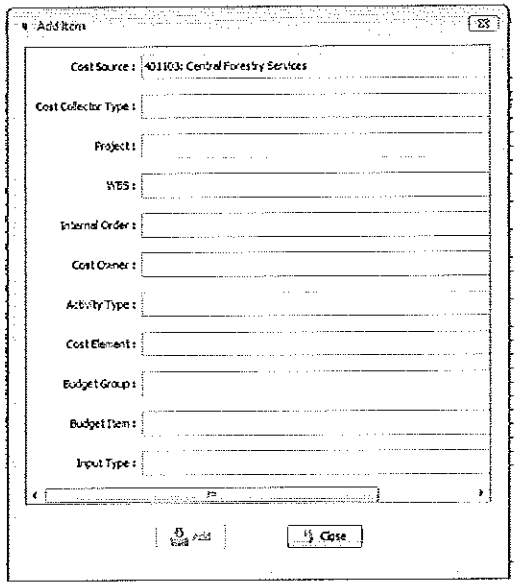
- <Edit in Excel> - Copies Grid data (Directs) to Excel for editing and then pastes it back into UIP.
- <Export to Excel (All Types)> - Sends ALL Budget Grid data to Excel to SAVE (can be imported).
- <Pivot Table> - Sends Budget Grid data to Excel and sets it up in Pivot Table format.

Add Budget Grid Data Overview

Multiple ways to enter data to the Grid



Add button with Edit Combo drop down

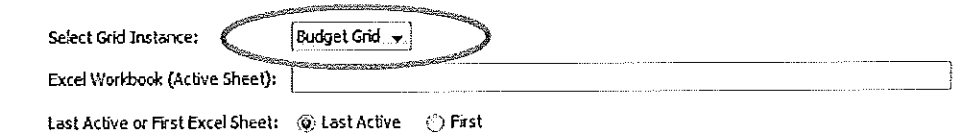


Edit in Excel or
Right Click in grid and
select *"Copy to Excel"*



	A	B	C
1			
2	Cost Center	Receiving Cost Center	Cost Collector Type
3	0000401001: Central Reg	0000401001: Central Regi	COST CENTER: Cost Ce
4	0000401001: Central Reg	0000401001: Central Regi	COST CENTER: Cost Ce
5	0000401001: Central Reg	0000401001: Central Regi	COST CENTER: Cost Ce
6	0000401001: Central Reg	0000401001: Central Regi	COST CENTER: Cost Ce

To import saved data return to Browse Cost Center screen and right click – select *"Import" (file must be on C: drive)*



All entries are validated prior to save to ensure accurate values were selected

Add Budget Grid Combination

Right click in box to either select value or enter directly

1. <Add> button with drop down

Cost Centers will be limited based on the user security →

Cost Collector defaults "N/A" if Cost Collector Type not selected. A drop down of valid cost collectors for owner selected will display →

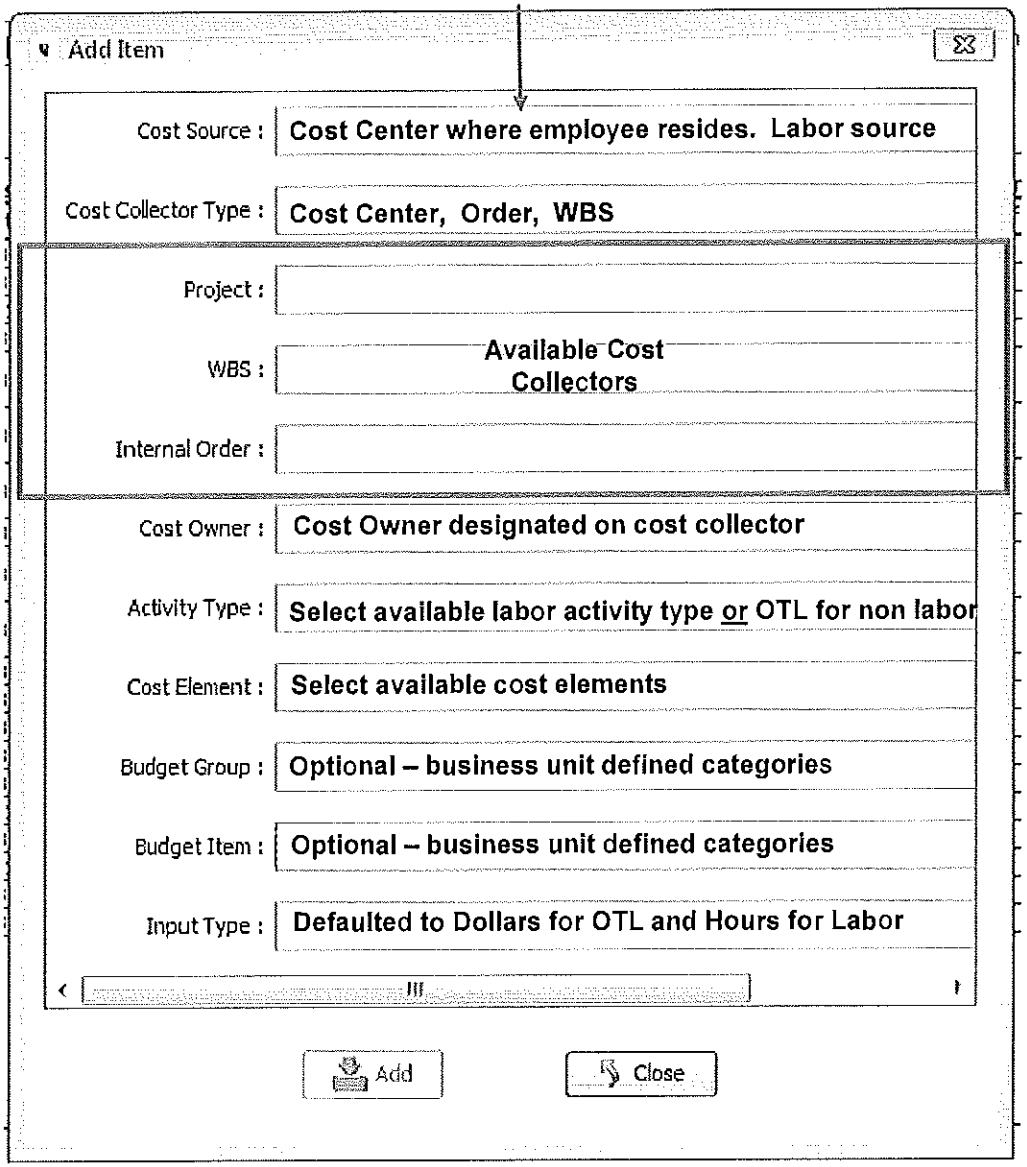
When budgeting Labor, this will be the Cost Center being billed for the Labor.
When budgeting OTL, this will be the same as the Cost Source →

Will be required only for Labor. Should be set to 'OTL' when budgeting OTL. Contractor hours and dollar value available →

Appropriate cost elements display (labor or OTL or Contractor/Prof Services). Ability to lock cost elements →

Allows user to apply more detail to the budget. Budget Groups might include Travel or Office Supplies. →

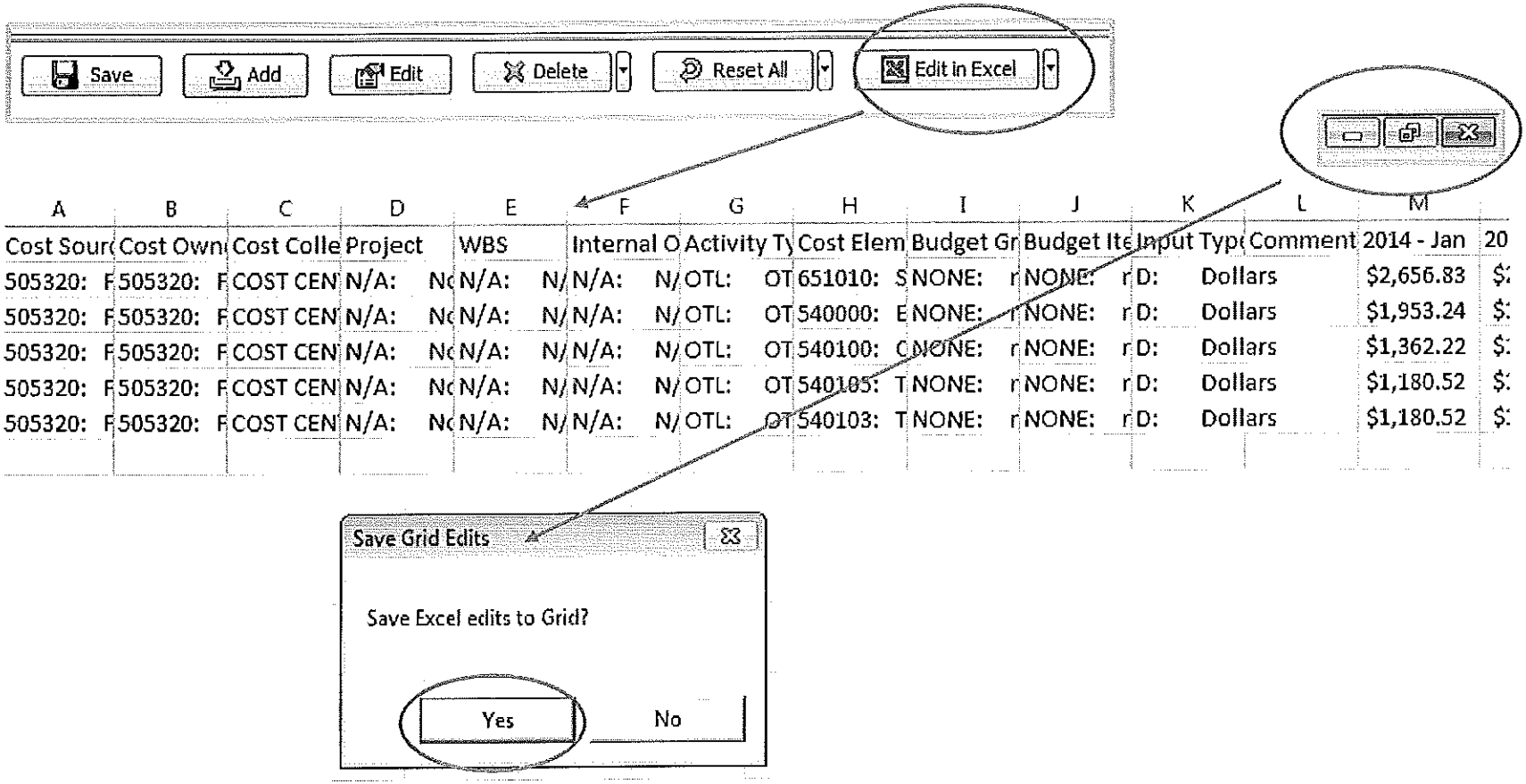
Allows user to apply more detail to the budget. Budget Items might include Airfare, Hotel and Meals for the Budget Group of Travel. →



Add Budget Grid Combination

2 Edit in Excel

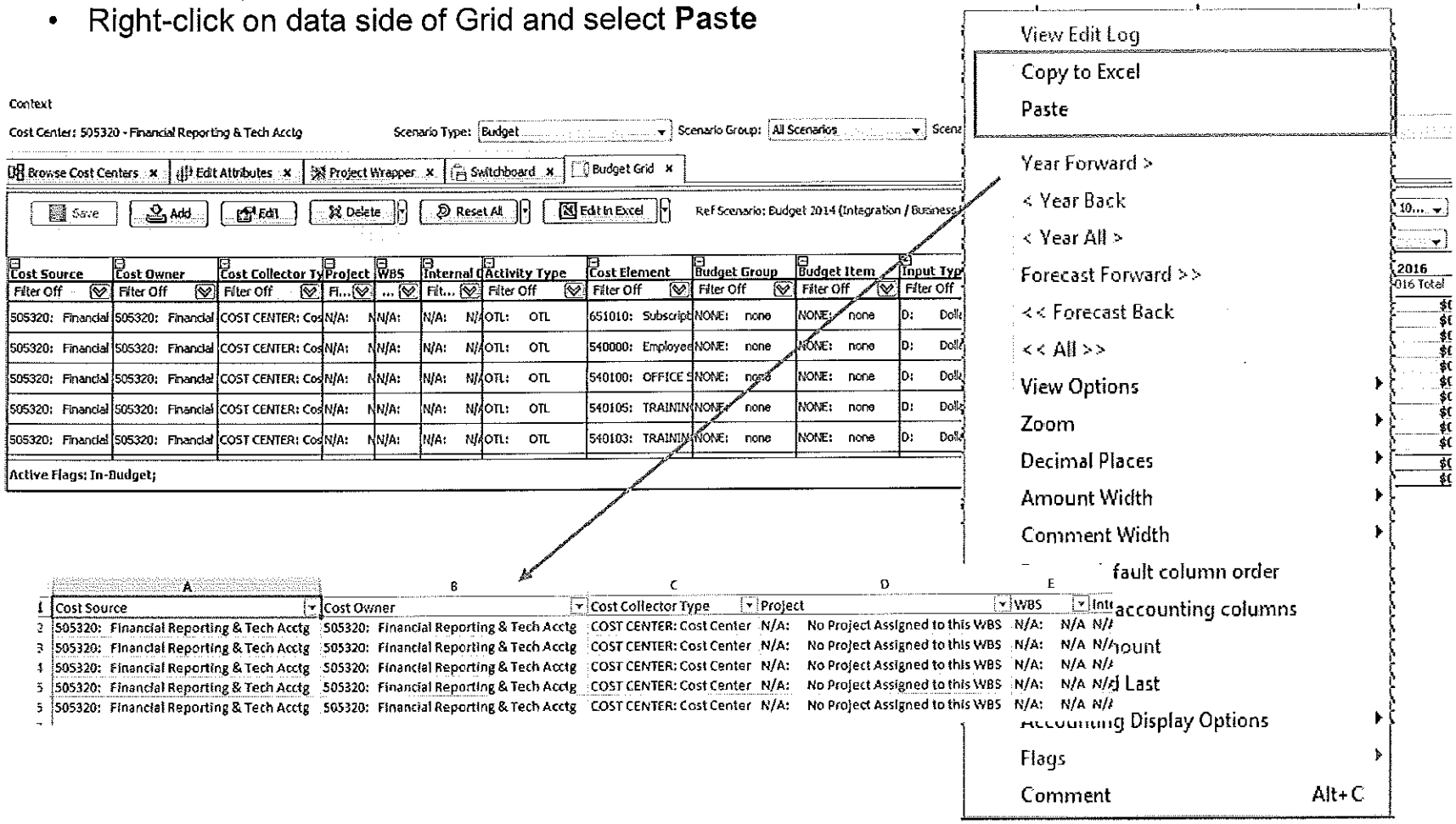
- Select **Edit in Excel** button
- When Excel opens, enter values in desired cells' dollars or make adjustments to existing values
- Click the "X" button to save back to the grid



Add Budget Grid Combination

3 Copy to Excel

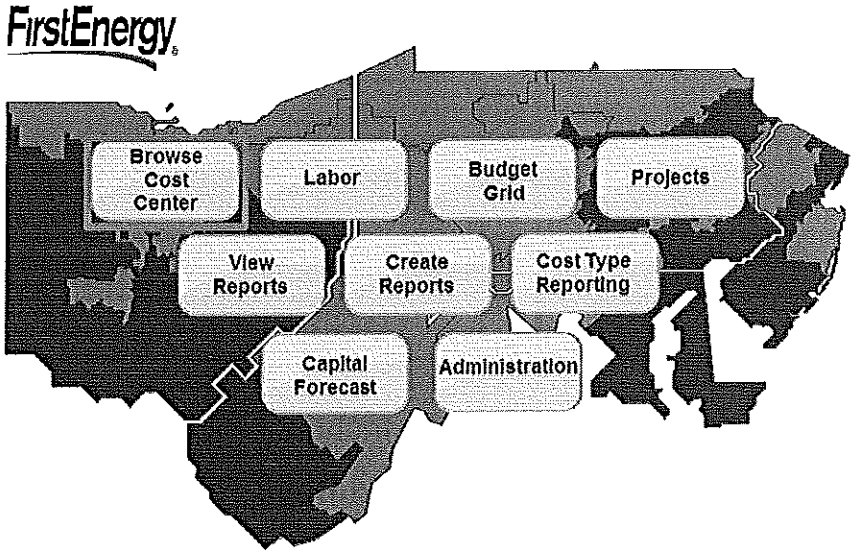
- Right-click on data side of Grid and select **Copy to Excel**
- Enter values in desired cells
- When completed, highlight sheet, select "copy"
- Right-click on data side of Grid and select **Paste**

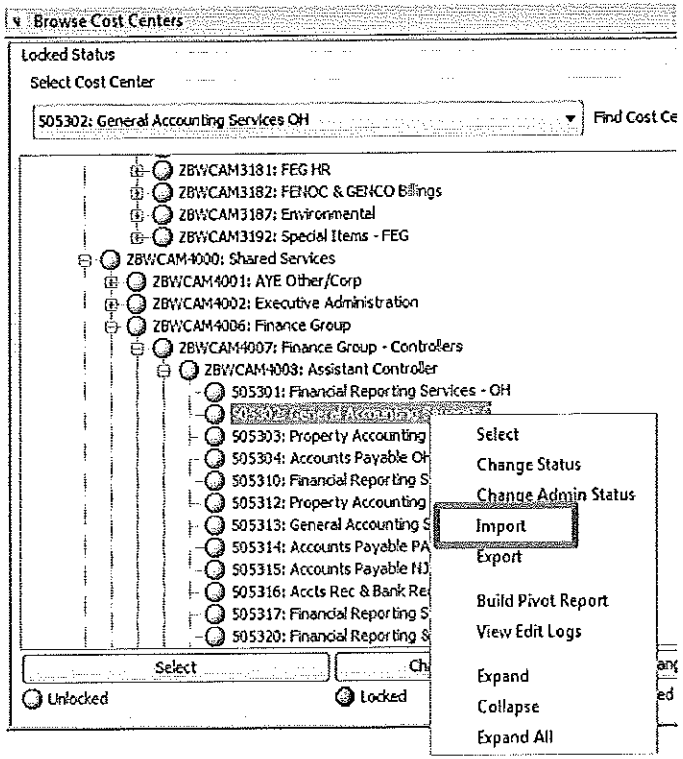


Add Budget Grid Combination

4 Import Budget Grid Data

- Open **FE Switchboard**
- Click **Browse Cost Center**
- Right click on any Cost Center
- Select "Import" from the menu window



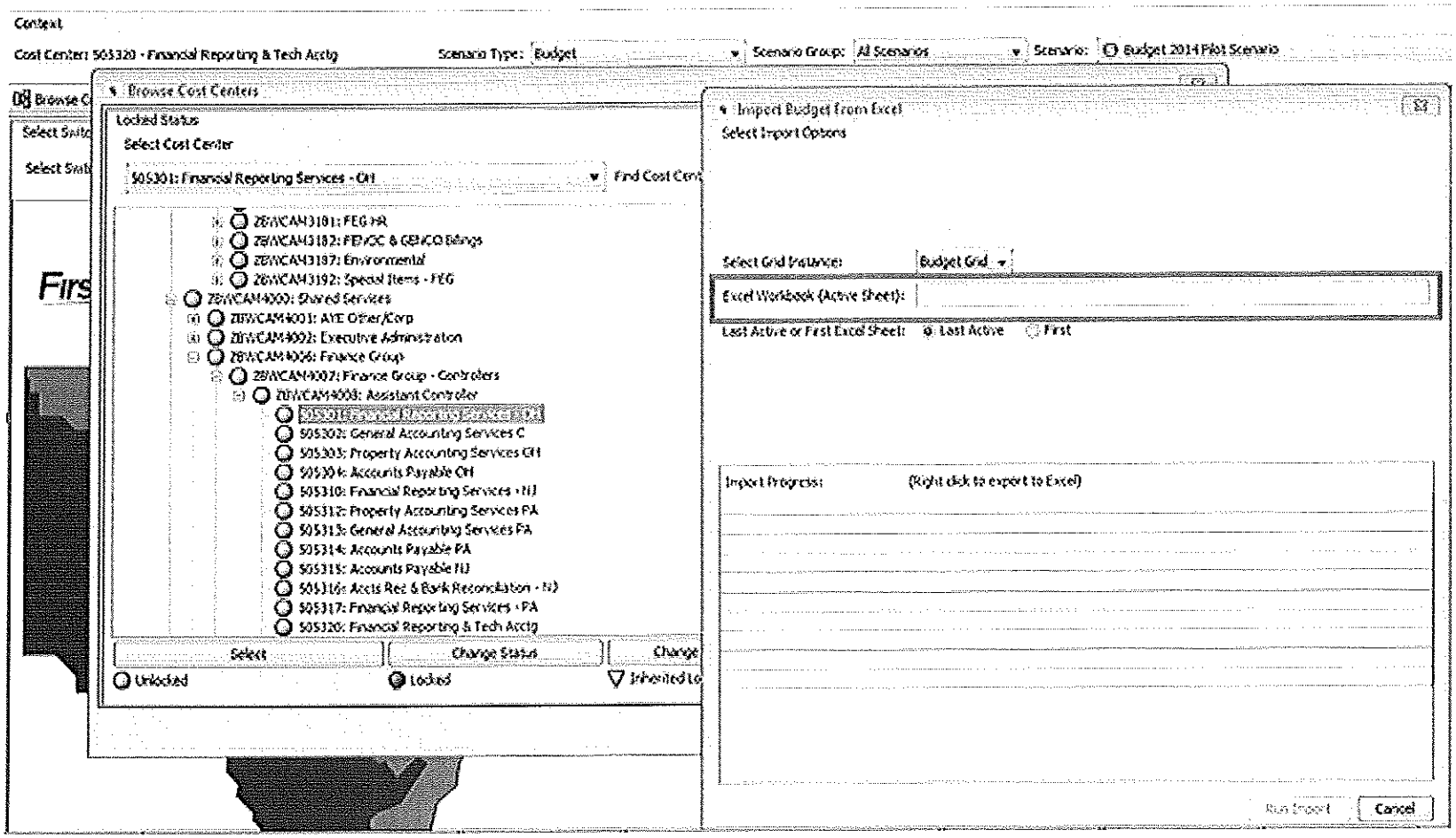


Note: This method is primarily used for data imports. Users should select the **Edit in Excel** button or **Copy to Excel** option for basic budget grid entry

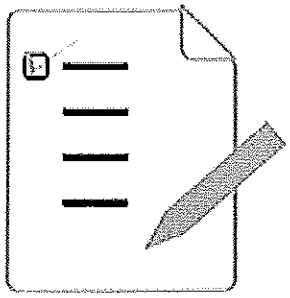
Add Budget Grid Combination

continued

4. Click in the "Excel Workbook (Active Sheet)" window
   - Browse through "C:/" drive to find import spreadsheet
   - NOTE: Spreadsheet must have all the same fields as displayed on the budget grid



Exercise #1 – Budget Grid Entry and Functionality



- Customize your Grid
- Add a budget grid combination by using the Add button
- Export the budget Grid to Excel and make additional changes. Populate multi-year. Copy back to Grid
- Perform other grid functions
- Add an existing Budget Group and Budget Item for a selected Cost Center
- Add comments to various Grid combinations
- Create a new Budget Group and Budget Item for a selected Cost Center
- Start developing your Budget Group and Budget Item categories for the 2014 budget process. *Users should complete their list on paper before creating in UIPlanner to ensure consistency and avoid duplication*

Project Planning and Tracking

Project Planning and Tracking Overview

- SAP Projects and WBS elements will be used for all current year projects
  - Project/WBS list from SAP will be refreshed every 60 minutes along with all attributes
- Planning Projects (conceptual projects) will be created and managed in UIPlanner for multi-year forecasts
  - Create Planning Projects using templates
  - UIPlanner will derive key attributes - user can populate remaining attributes
  - Some attributes will be required fields
- There is a process for when a Planning Project becomes "real", i.e., is in SAP
- Current list of attributes is on the next slide. Ability to create additional attributes

Current Year	Multi-Year
SAP Projects	**UI Planning Projects**
• Approved projects in the current year • Project definition and WBS elements exists in SAP • Ability to track actuals vs. budget	• Unapproved Projects in the queue • Planning projects (project definition and WBS elements) mirror real SAP structures but utilize UIP naming conventions • SAP project templates utilized as starting point

- Mirroring the SAP project to the UI Planning Project ensures important attributes such as the Costing Sheet data are applied accurately and automatically
- Budget close will work in the same manner for the multi-year planning process

PROJECT / WBS ATTRIBUTES IN UIPLANNER

PROJECT

From SAP
- Budget Profile
- Changed By
- Changed On Date
- Company (Required)
- Cost Object
- Created By
- Created On Date
- Definition
- Description
- Estimated In Service Date
- Forecast Finish Date (FRCST)
- Forecast Start Date
- In SAP (Y/N)
- Integrated Planning
- Interest Profile
- Investment Profile
- Name of Person Responsible
- Network Profile
- Number
- Object Class
- Object Number
- Owning Center
- Person Responsible
- Plant
- Profit Center
- Start Date (Required)
- Tax Jurisdiction

xRPM
- xRPM Number
- Bucket Name
- Business Unit Sponsor
- CART Data Fields (determine which ones)
- CART ID Number
- Detailed Description
- Multi-Year Flag

RPA
- RPA Number
- Sponsor (bulk, region, other)
- Sponsor Need Date
- Status
- Initiative Code (used by Transmission to provide additional visibility
- Lead (name)

One List
- One List Number
- Sponsor (actual name)
- Plant Designator
- Plant Unit # (BV1, etc)
- Investment Profile Text Field (define a sub category)
- Program Manager (actual name)
- Nuclear Fuels (Y/N)
- Outage Code (denotes which outage)
- Text Field (EUCG capital category for benchmarking)
- Text Field (text box for reporting owner name)

Other
- Profile
- End Date (Required)
- Budgetable (Y/N)
- In-Budget Flag

WBS

From SAP
- Company Code
- Cost Center
- Project
- Profit Center
- Object Class
- Estimated In-Service Date (PRPS)
- Closing Option
- Costing Sheet
- Project Type
- Element String
- Element (PSPID)
- Element (PSPNR)
- Interest Profile
- Base/Recoverable/Major Projects
- Created On (date)
- Created By
- Changed On (date)
- Changed By
- Requesting Cost Center

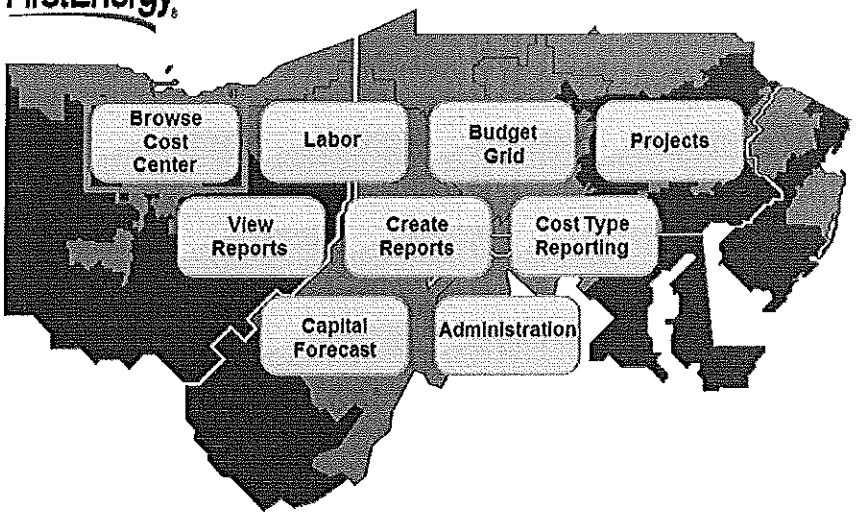
From SAP
- Investment Profile (mandatory, maintain, value add, improve)
- Scale of investment
- Reason for Environmental Investment
- Investment Reason
- Costing Variant
- Cost Object
- Object Number
- Planning Element
- Integrated Planning
- Priority
- Currency
- Level
- Technically Complete
- Tax Jurisdiction
- Name of Person Responsible
- Person Responsible
- Plant
- Overhead Key
- In SAP

PowerPlant
- Depr Group
- Estimated In-Service Date (PPLANT)
- Eligible for AFUDC
- Eligible for CPI
- AFUDC Type
- In PowerPlant

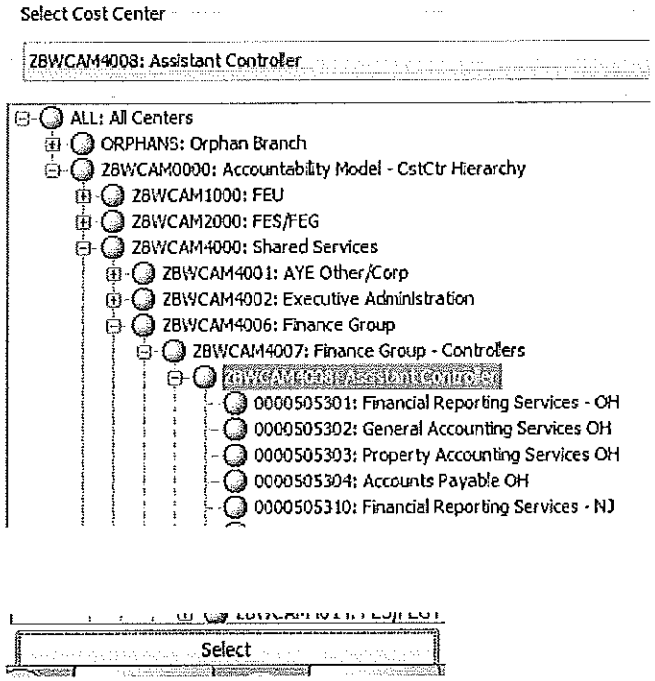
Other
- Budgetable (Y/N)
- Status
- Template (Y/N)
- Element Description

Project Planning and Tracking Startup

1. Define a Context Cost Center
   - Open the **FE Switchboard**
   - Click **Browse Cost Center**

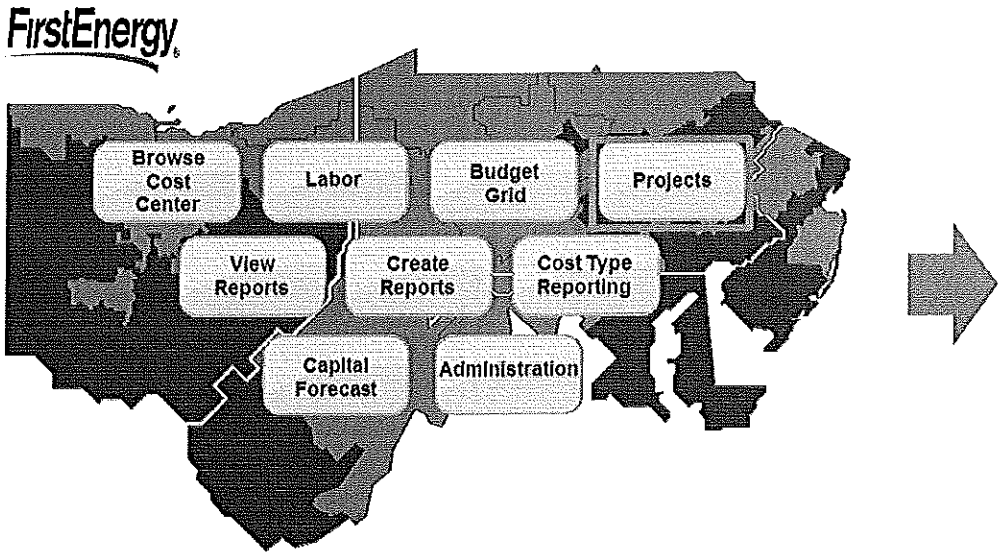


2.
   - Select a Cost Center (either double-click Cost Center or highlight Cost Center and click the **Select** button on the bottom of screen)
   - **Note:** Select the ALL node to view a full list of projects

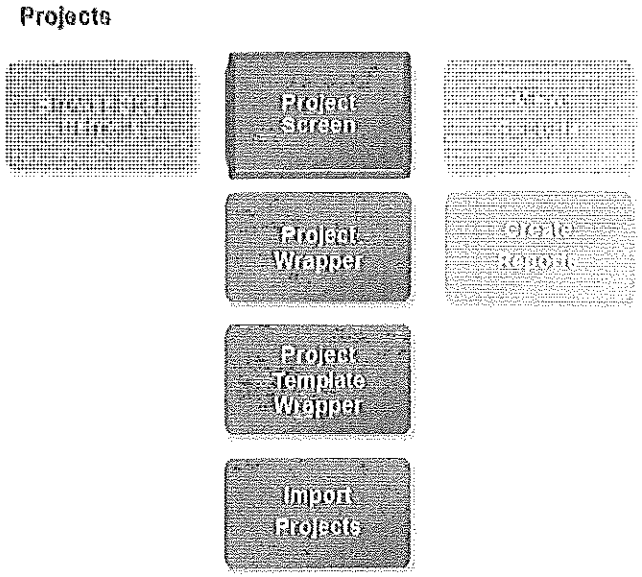


Project Planning and Tracking Startup

3 Open Project Screen
- Return to the **FE Switchboard**
- Click on the **Projects** button



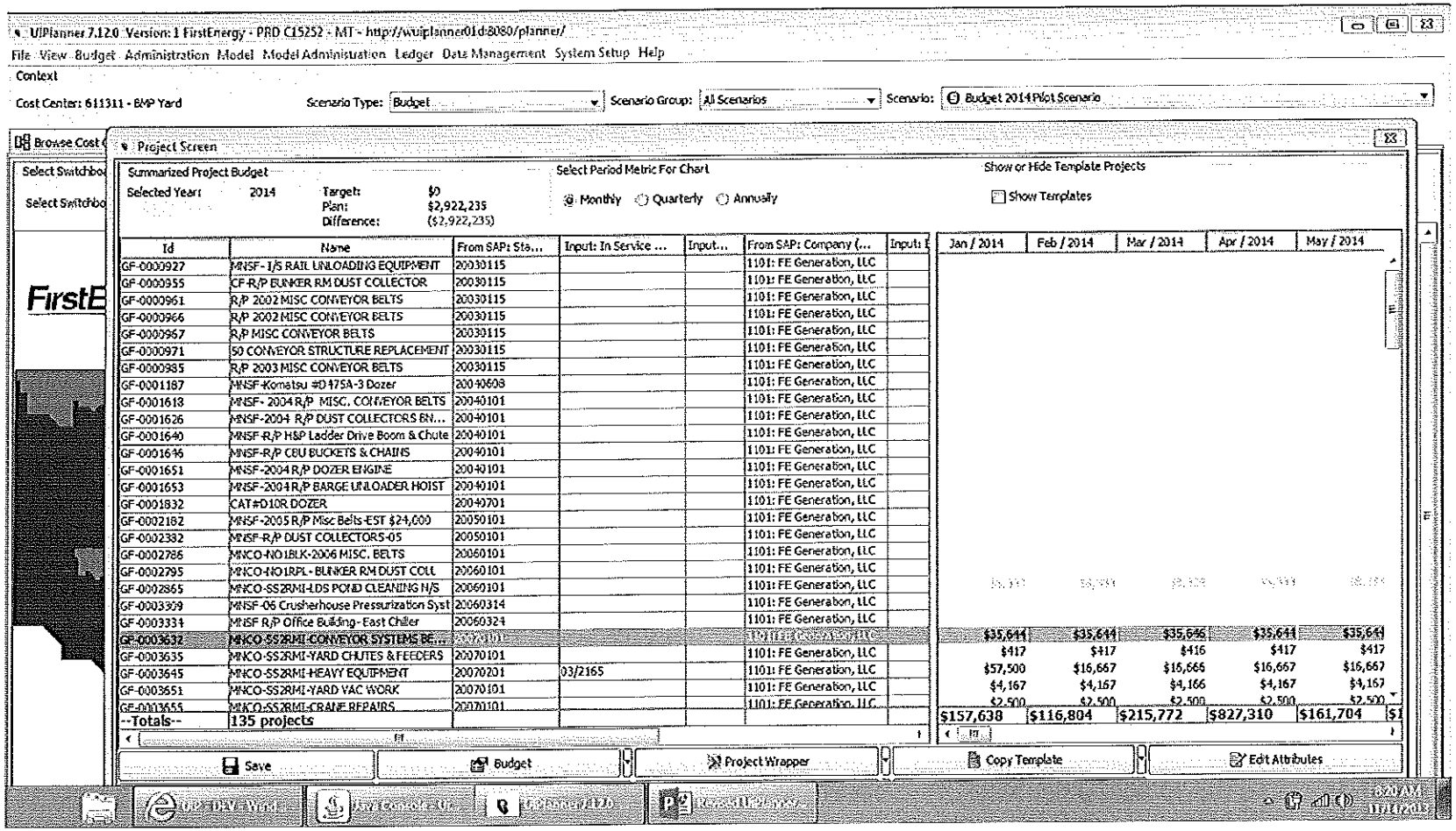
4
- Click **Project Screen** menu item



Project Planning and Tracking Screen Navigation

5

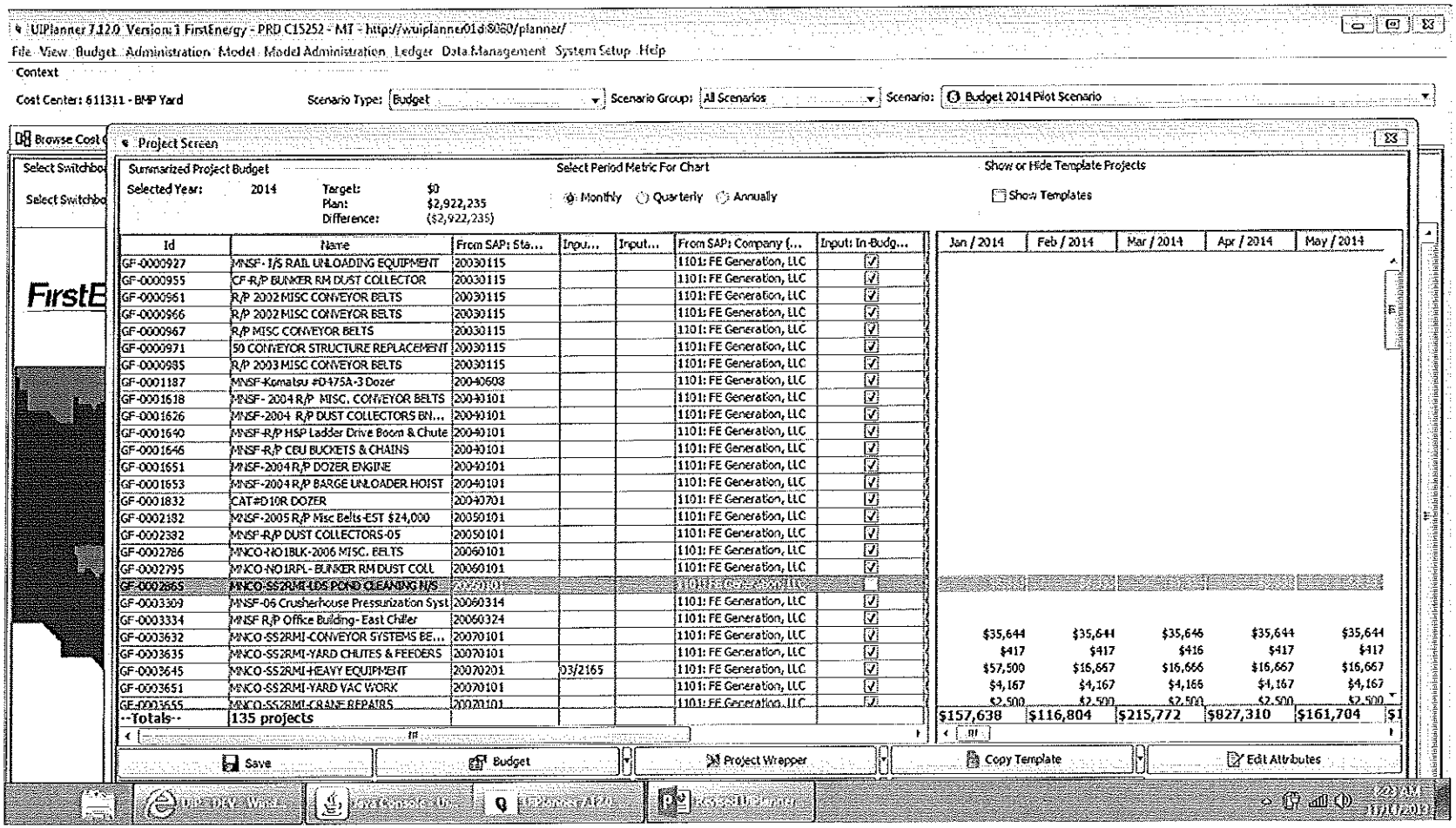
- Move projects from year to year
  - Select dollar amount for a given project and drag to a different year
  - Changes will automatically update Grid keeping the Project Screen and Budget Grid in sync
  - Note: you cannot drag projects that have already started (i.e. have amounts in actuals months)
- Change the column display (Monthly, Quarterly, or Annual)



Project Planning and Tracking Screen Navigation

6

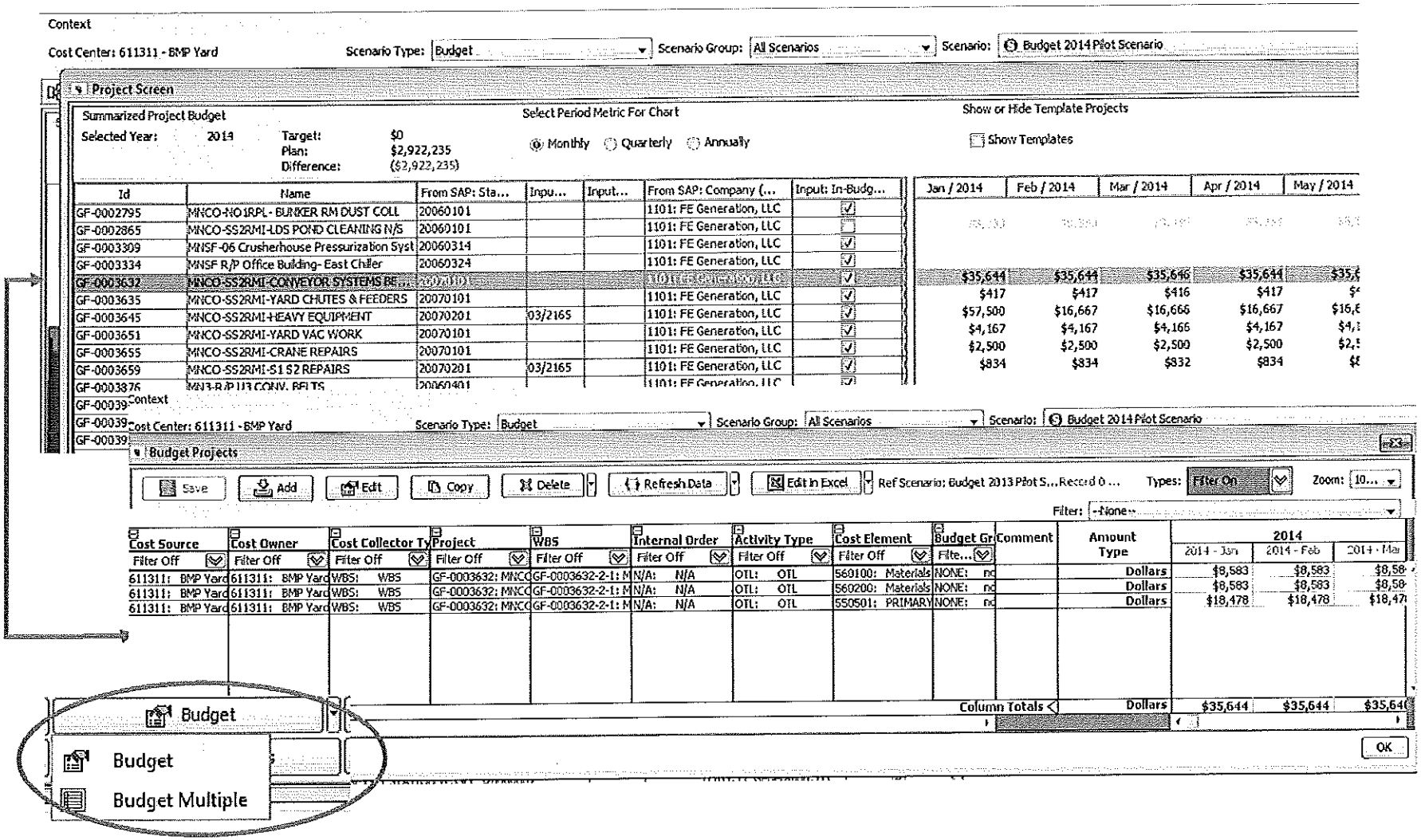
- Turn projects on and off (using the In-Budget flag)
  - The project spending will be grayed out
  - It will be excluded from the totals
  - Click on a column, and the top of the screen shows the totals against the target for that year



Project Planning and Tracking Budgeting

7

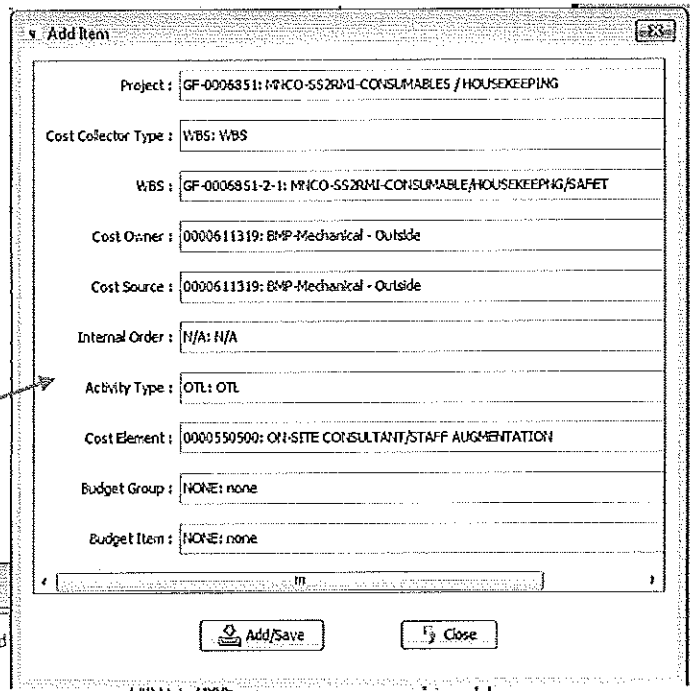
- Select Budget button on bottom of screen to view projects in the budget grid
- Use the droplist on the side of the button to choose whether to budget one project or multiple projects

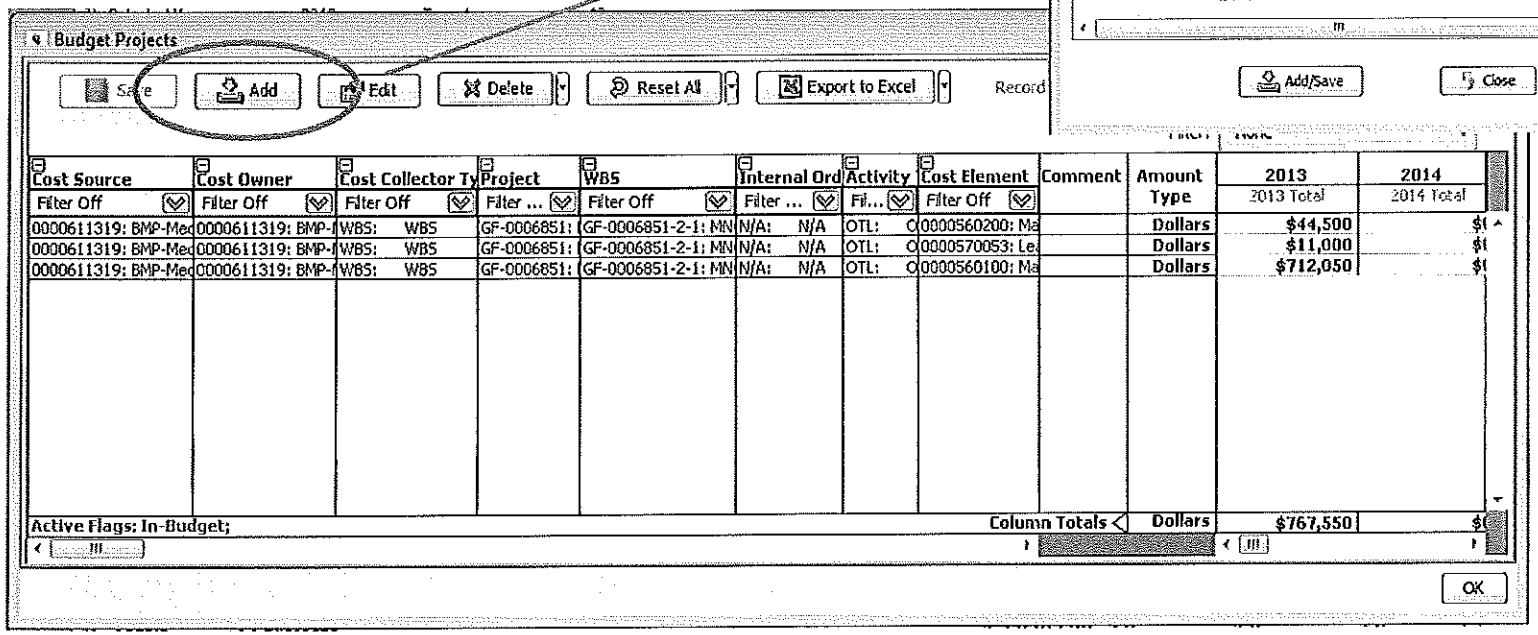


Project Planning and Tracking - Add Combo

8

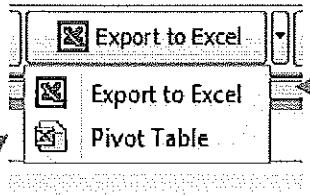
- Budget Grid - Project View
  - All Grid functionality
    - Dollars, Hours
    - Enter or paste from Excel
    - Monthly, Annual
    - Grouping and filters
    - Right-click options
  - Add Combos
    - Project Validations - fills in the available choices for the next field
    - Some fields are prepopulated





Project Planning and Tracking – Export to Excel / Pivot Table

9 • Select **Export to Excel/Pivot** button on bottom of screen to send the screen contents to Excel
  • Select the dropdown on the right of the button to choose raw Excel or a Pivot table



Microsoft Excel - Data Export 1375311570091.txt.xls

	A	B	C	D	E	F	G	H	I	J	K
1	Id	Name	Input: In-Budget Flag	From SAP: Interest Profile	F	Input: End Date (Required)	2,013	2,014	2,0	2,0	2,0
2	GF-0002866	MN03-SS2RMI-SO2 CONTRACTOR U3	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,061,231	200,000				
3	GF-0002872	MN01-SS2RMI-SO2 CONTRACTOR U1	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,061,231	74,000				
4	GF-0002873	MN02-SS2RMI-SO2 CONTRACTOR U2	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,061,231					
5	GF-0003520	MNCO-SS2RMI-SCR CLEANING UNIT 1, 2 & 3	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,471,231	425,000				
6	GF-0004017	MNCO-SS2RMI-SBS LICENSE FEE BMP	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,480,118					
7	GF-0004031	MNCO-SS2RMI-HYDROGEN BMP	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,480,118					
8	GF-0004032	MNCO-SS2RMI-CO2 BMP	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,480,118	25,000				
9	GF-0005041	MNCF-R/P NO 1 JOY INTERCOOLERS 2007	TRUE								
10	GF-0005075	MNCO-NO1RPL-SHIFT SUPERVISOR OFFICE REN	TRUE		0000	20,080,331					
11	GF-0005118	MNSF PURCHASE KAWASAKI MULE-2007	TRUE								
12	GF-0005119	MNCO- TELEDYNE MODEL2750 H2 GAS ANALYZER	TRUE								
13	GF-0005357	MNCO-SS2RMI-LUBRICANTS & KEROSENE OPS	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,201,231	280,660				
14	GF-0005358	MNCO-SS2RMI-FLOC STOCK OPERATIONS	FALSE	PRDSTMO: Steam Fossil O&M	0000	20,201,607		195,000			
15	GF-0006356	MNCO-SS2RMI-U1B U2 TRAIN CLG-OPS	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,091,231					
16	GF-0006357	MN03-SS2RMI-U3 ABS/REACTOR-OPS	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,091,231					
17	GF-0006358	MNCO-SS2RMI-REPLACEMENT-VIC P&H ETC	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,091,231					

A2 fx From SAP: Profit Center

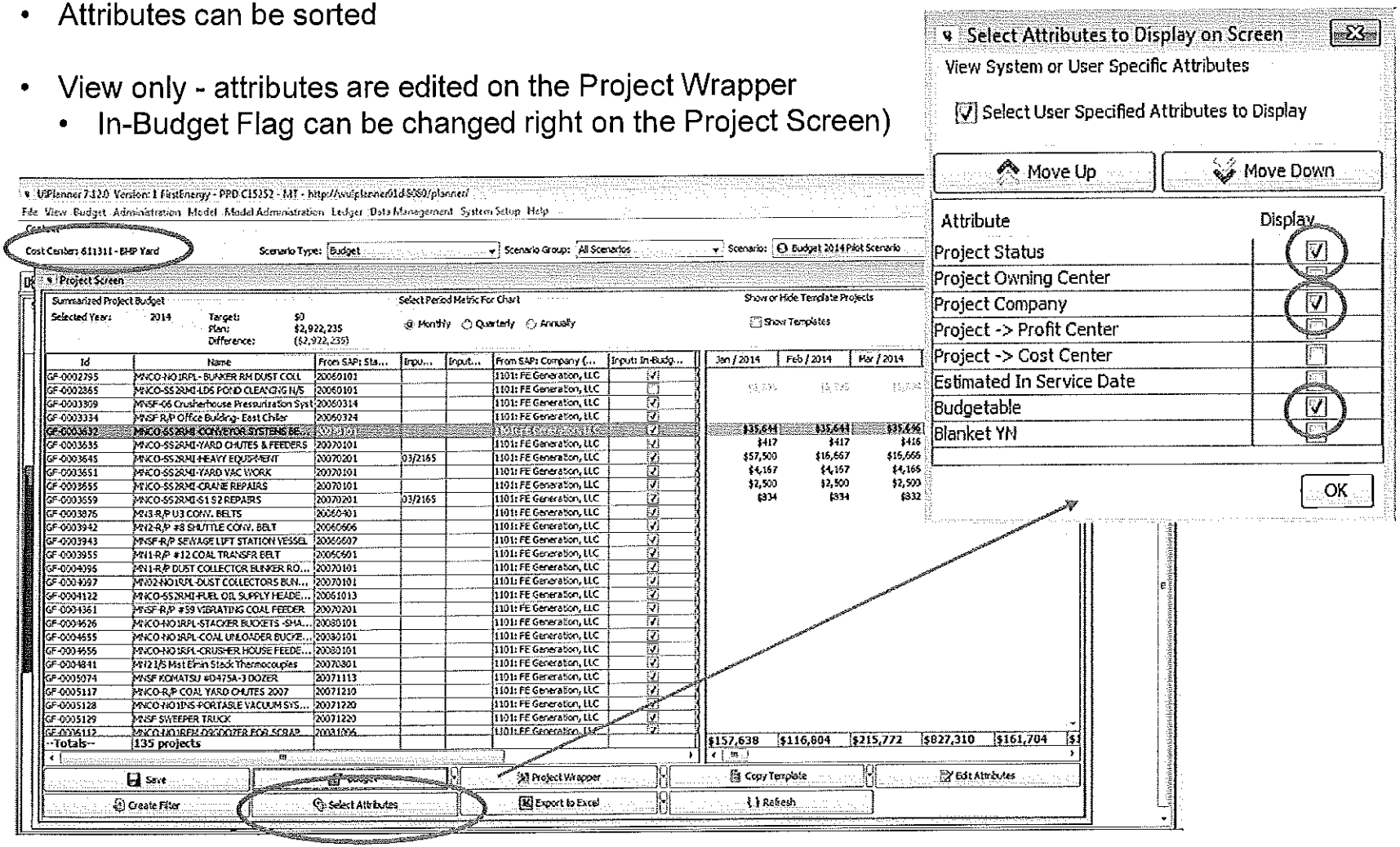
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	Input: End Date (Required)	(All)													
2	From SAP: Profit Center	(All)													
3	From SAP: Interest Profile	(All)													
4	Input: In-Budget Flag	(All)													
5	Last Used By	(All)													
6	Scenario	(All)													
7															
8	Sum of Value		Year	Month											
9			2014												2014 Total
10	Project	Last Used	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
11	GF-0002866: MN03-SS2RMI-SO2 CONTRACTOR U3	(blank)	16667	16667	16666	16667	16667	16666	16667	16667	16666	16667	16667	16666	200000
12	GF-0002866: MN03-SS2RMI-SO2 CONTRACTOR U3 Total		16667	16667	16666	16667	16667	16666	16667	16667	16666	16667	16667	16666	200000
13	GF-0002872: MN01-SS2RMI-SO2 CONTRACTOR U1	(blank)	74000												74000
14	GF-0002872: MN01-SS2RMI-SO2 CONTRACTOR U1 Total		74000												74000
15	GF-0003520: MNCO-SS2RMI-SCR CLEANING UNIT 1, 2 & 3	(blank)	35417	35417	35416	35417	35417	35416	35417	35417	35416	35417	35417	35416	425000
16	GF-0003520: MNCO-SS2RMI-SCR CLEANING UNIT 1, 2 & 3 Total		35417	35417	35416	35417	35417	35416	35417	35417	35416	35417	35417	35416	425000
17	GF-0004032: MNCO-SS2RMI-CO2 BMP	(blank)	2083	2083	2084	2083	2083	2084	2083	2083	2084	2083	2083	2084	25000
18	GF-0004032: MNCO-SS2RMI-CO2 BMP Total		2083	2083	2084	2083	2083	2084	2083	2083	2084	2083	2083	2084	25000
19	GF-0005357: MNCO-SS2RMI-LUBRICANTS & KEROSENE OPS	(blank)	23389	23389	23387	23389	23389	23387	23389	23389	23387	23389	23389	23387	280660
20	GF-0005357: MNCO-SS2RMI-LUBRICANTS & KEROSENE OPS Total		23389	23389	23387	23389	23389	23387	23389	23389	23387	23389	23389	23387	280660
21	GF-0005358: MNCO-SS2RMI-FLOC STOCK OPERATIONS	(blank)													
22	GF-0005358: MNCO-SS2RMI-FLOC STOCK OPERATIONS Total														
23	GF-0006957: MNCO-SS2RMI-NON-SO2 CONTRACTORS OPS	(blank)							27917	27917	27916	27917	27917	27916	167500
24	GF-0006957: MNCO-SS2RMI-NON-SO2 CONTRACTORS OPS Total								27917	27917	27916	27917	27917	27916	167500
25	Grand Total		151,556	77,556	77,553	77,556	77,556	77,553	105,473	105,473	105,469	105,473	105,473	105,469	1,172,160

Project Planning and Tracking - Select Attributes

10

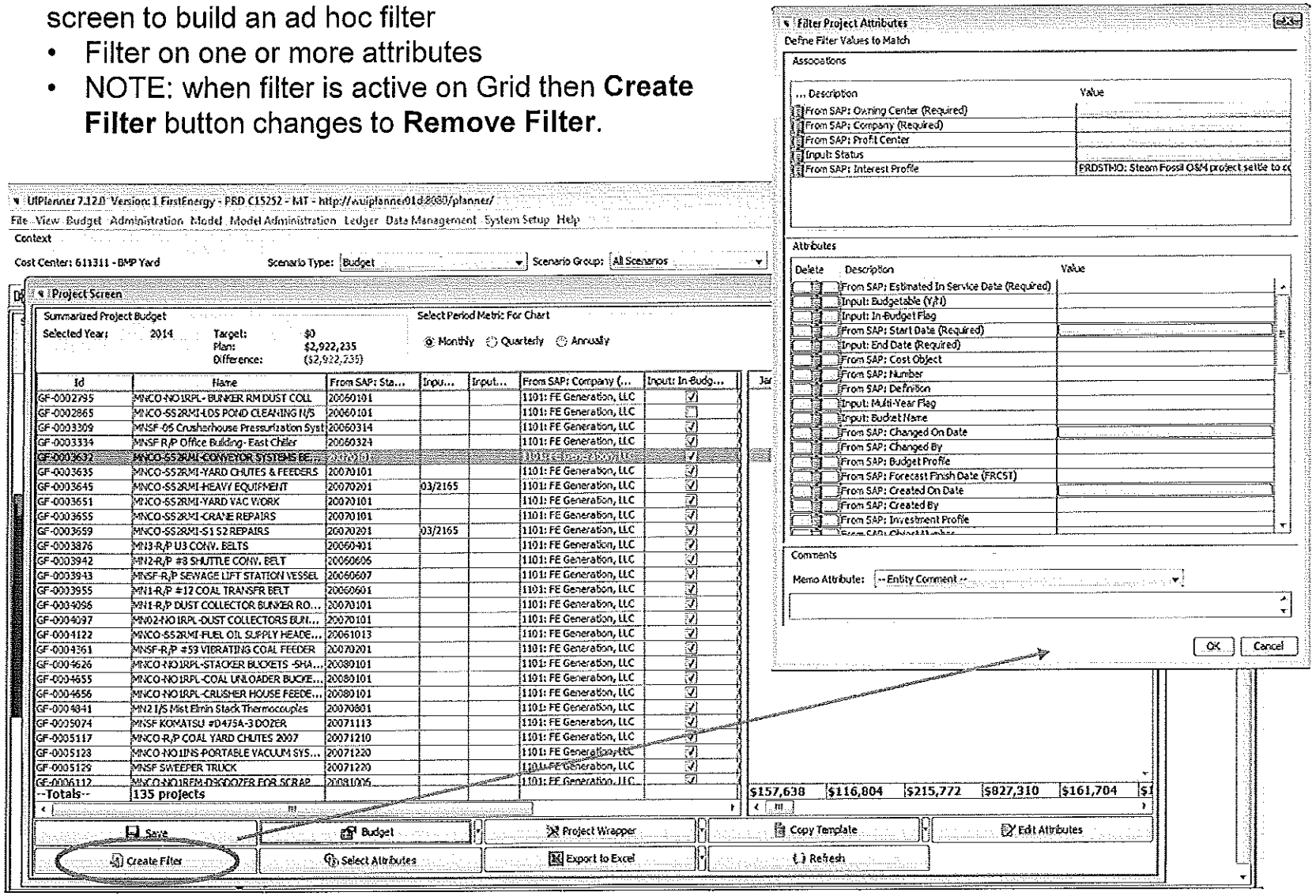
- Users can customize the project screen and view project attributes
- Select the **Select Attributes** button on bottom of screen
- Click on/off attributes you want to display
- Attributes can be sorted

- View only - attributes are edited on the Project Wrapper
  - In-Budget Flag can be changed right on the Project Screen)



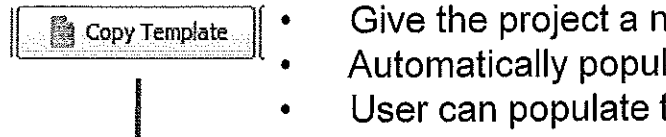
Project Planning and Tracking - Filters

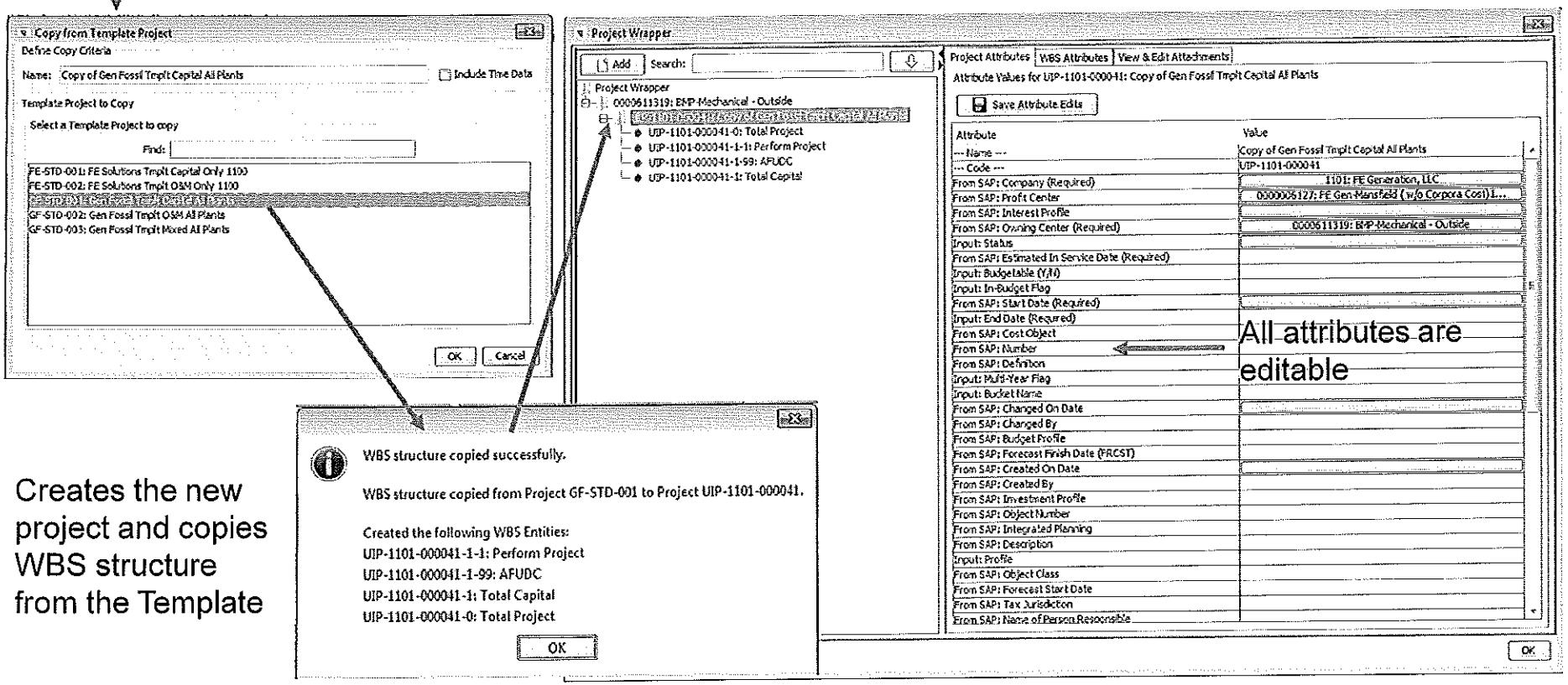
- Select the **Create Filter** button on the bottom of the screen to build an ad hoc filter
  - Filter on one or more attributes
  - NOTE: when filter is active on Grid then **Create Filter** button changes to **Remove Filter**.



Project Planning and Tracking - Create New Project

12 • Create Planning Project / WBS
  - Planning Projects/WBS will be created in UIPlanner
  - Based on Template Projects brought in from SAP
  - Hit the Copy Template button at the bottom of the Project Screen
    - Select a template from the list (templates are at rollup CC; available to CC under)
    - Give the project a name (starts with a default Copy of . . . .)
    - Automatically populates key elements (Company, Cost Center, Project, etc.)
    - User can populate the rest. All attributes are editable in the Project Wrapper



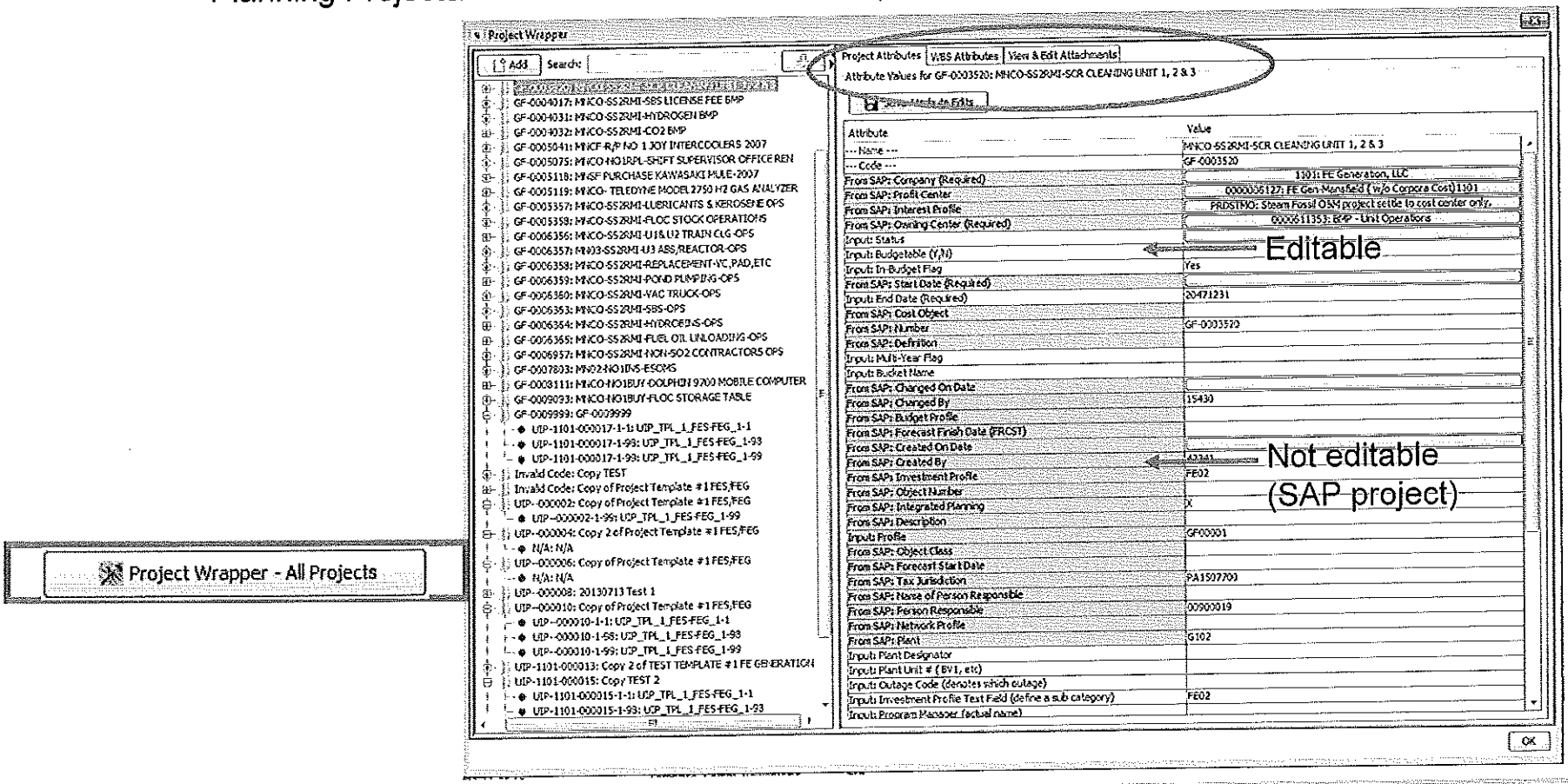


Creates the new project and copies WBS structure from the Template

Project Planning and Tracking - Project Wrapper

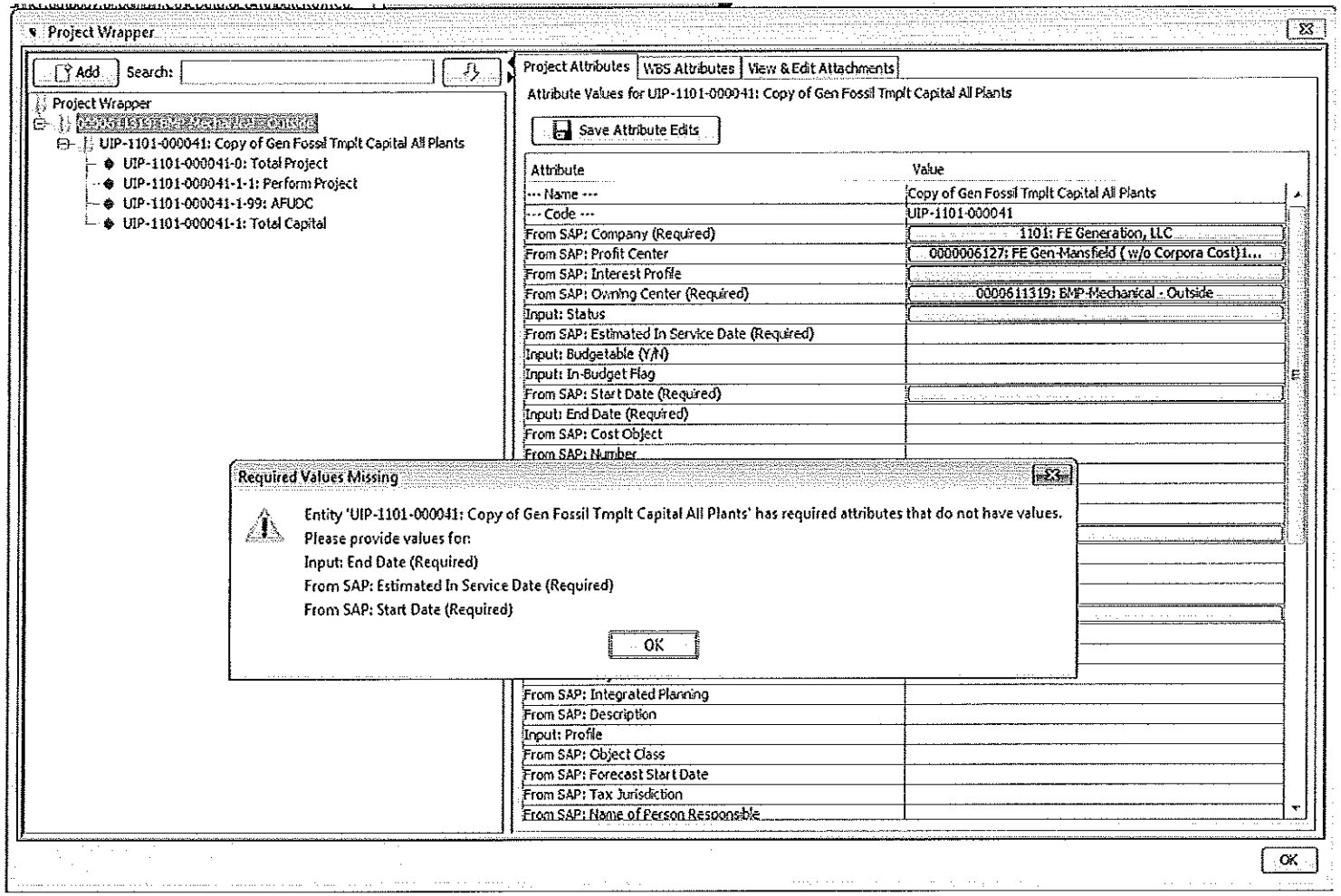
13

- Select the Project Wrapper button to open the Project Wrapper
  - Separate tabs for Project attributes and WBS attributes
  - Shows all attributes
    - Grayed out if you can not edit them
  - Rules for what can be edited and what cannot
    - Projects/WBS from SAP - attributes brought over and cannot be edited
    - Planning Projects/WBS - can edit all attributes (except ones populated by UIPlanner)



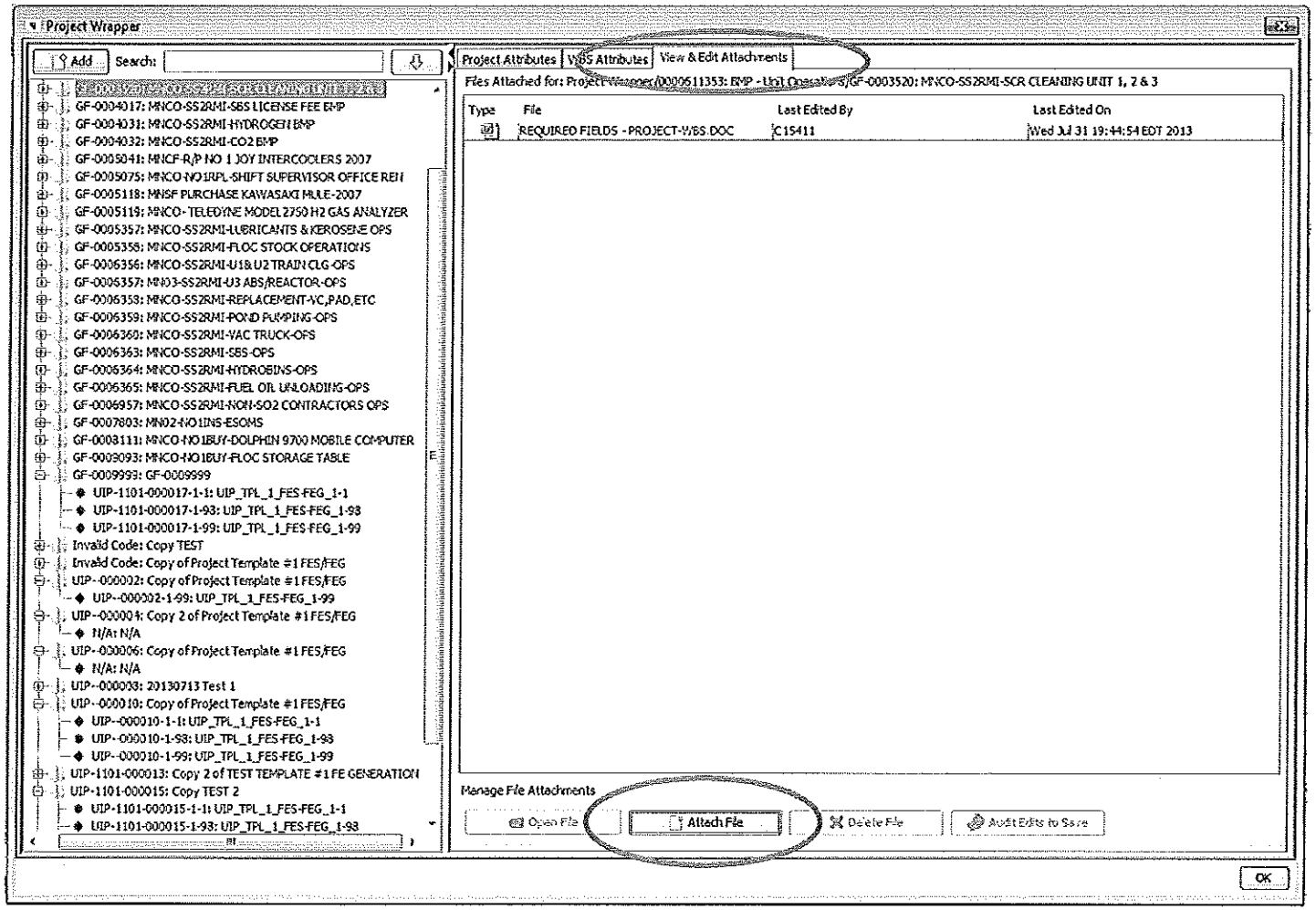
Project Planning and Tracking - Create New Project

14 • Certain fields for Projects and WBS are required
  - Needed in order to perform key calculations (closings, assessments, etc.)
  - Already populated for Projects/WBS from SAP
  - Need to make sure these are populated when you create a Planning Project

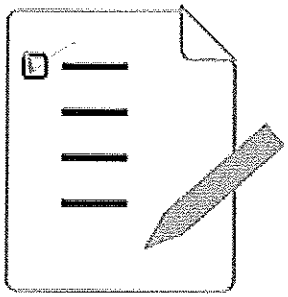


Project Planning and Tracking - Project/WBS Element Attachments

15 • Project Wrapper - Attachments
  - Select the View and Edit Attachment Tab
  - You can attach any document (DOC, XLS, etc.) to the project
  - Stored in the database and archived



Exercise #2 – Project Budget and Tracking



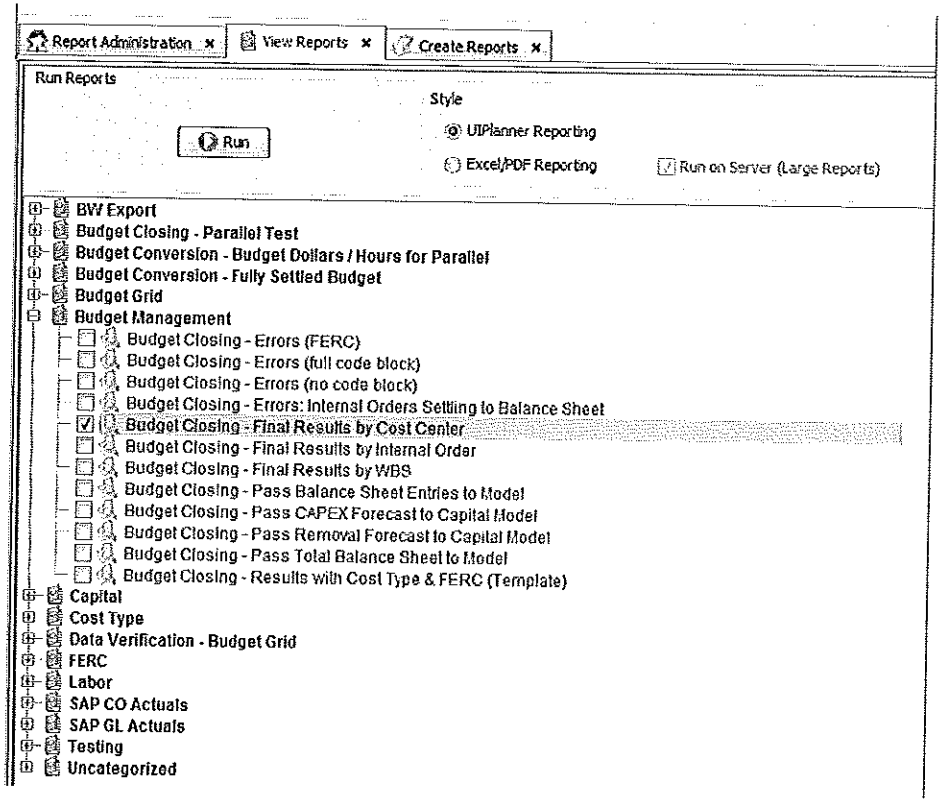
- Customize your Project Screen
  - Select attributes you would like to view
- Open the Budget Grid and make changes for a specific project
- Open Project Wrapper and view/edit project and WBS element attributes
- Export project to Excel pivot
- Create planning project using template

Reporting – Development and Usage

View Reports Screen

- Access View Reports screen by pressing Ctrl+F12 and typing "View Reports" or through a Report link from a Switchboard

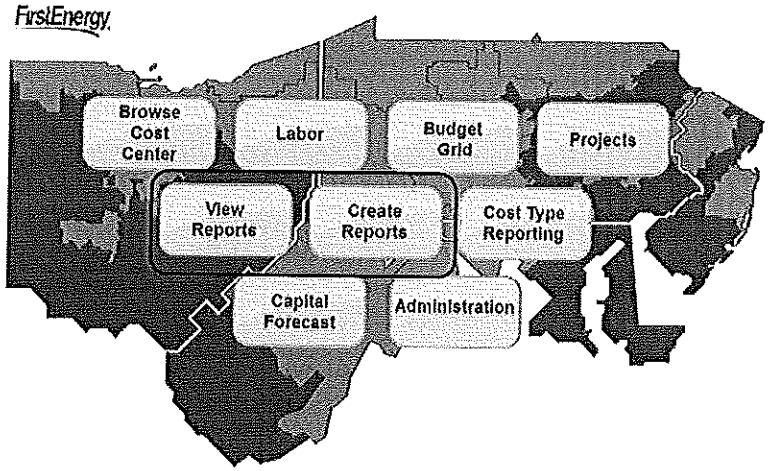
- Reports are published into thematic sections which can be expanded or collapsed by clicking on the +/- icon next to the section titles



View Reports screen

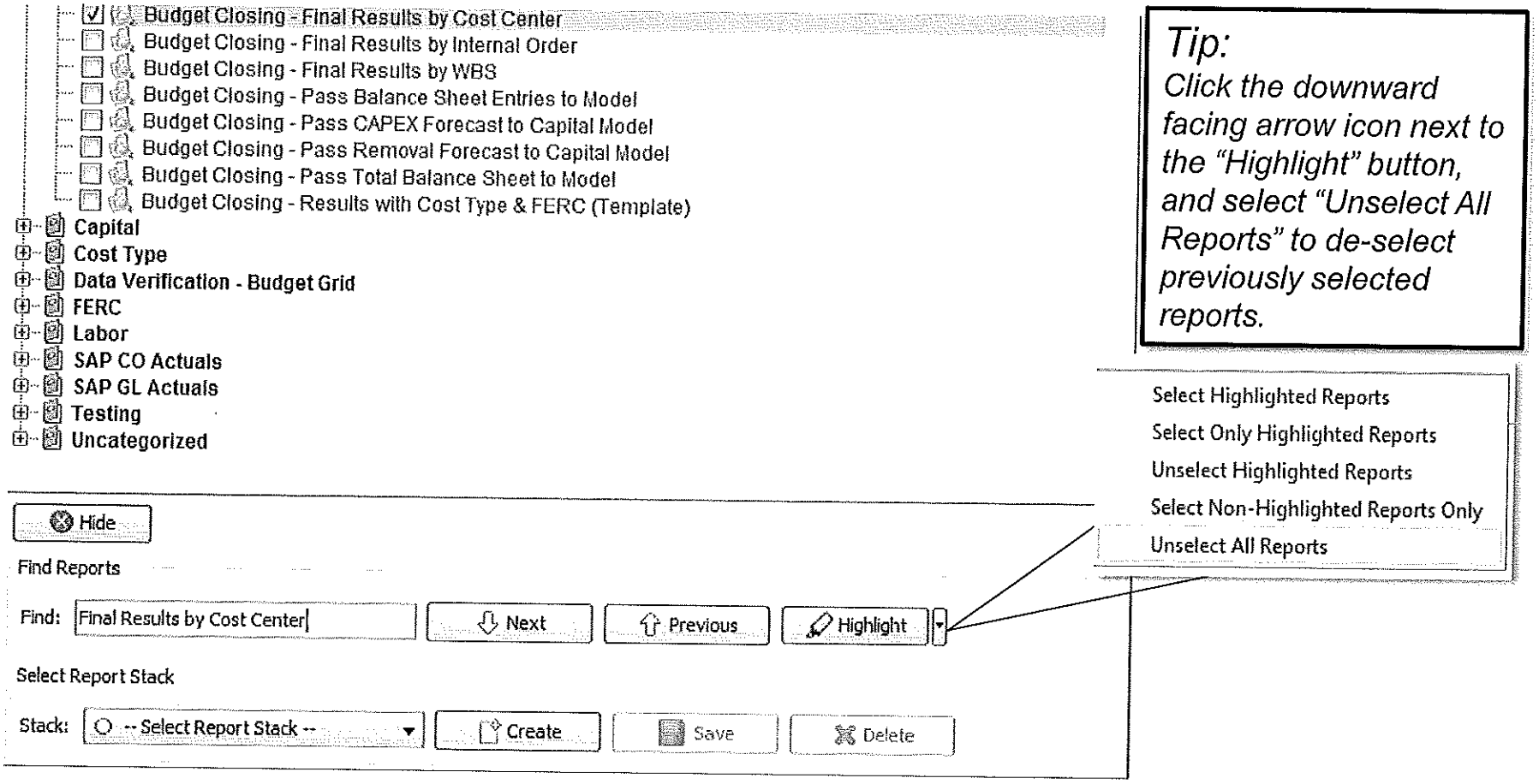
Tip:
Make sure that you have selected the correct Scenario before running reports.

Switchboard Reports



Finding Your Report

- Open Search controls by clicking the Search button at the bottom of the screen.
- Search by typing the name of your report. You can perform a "wildcard" search by adding "*" to your search terms. E.g. "*cost center*" will find any report that contains the phrase "cost center" within its name.
- Press the "Next" and "Previous" buttons to jump back and forth to the next results.

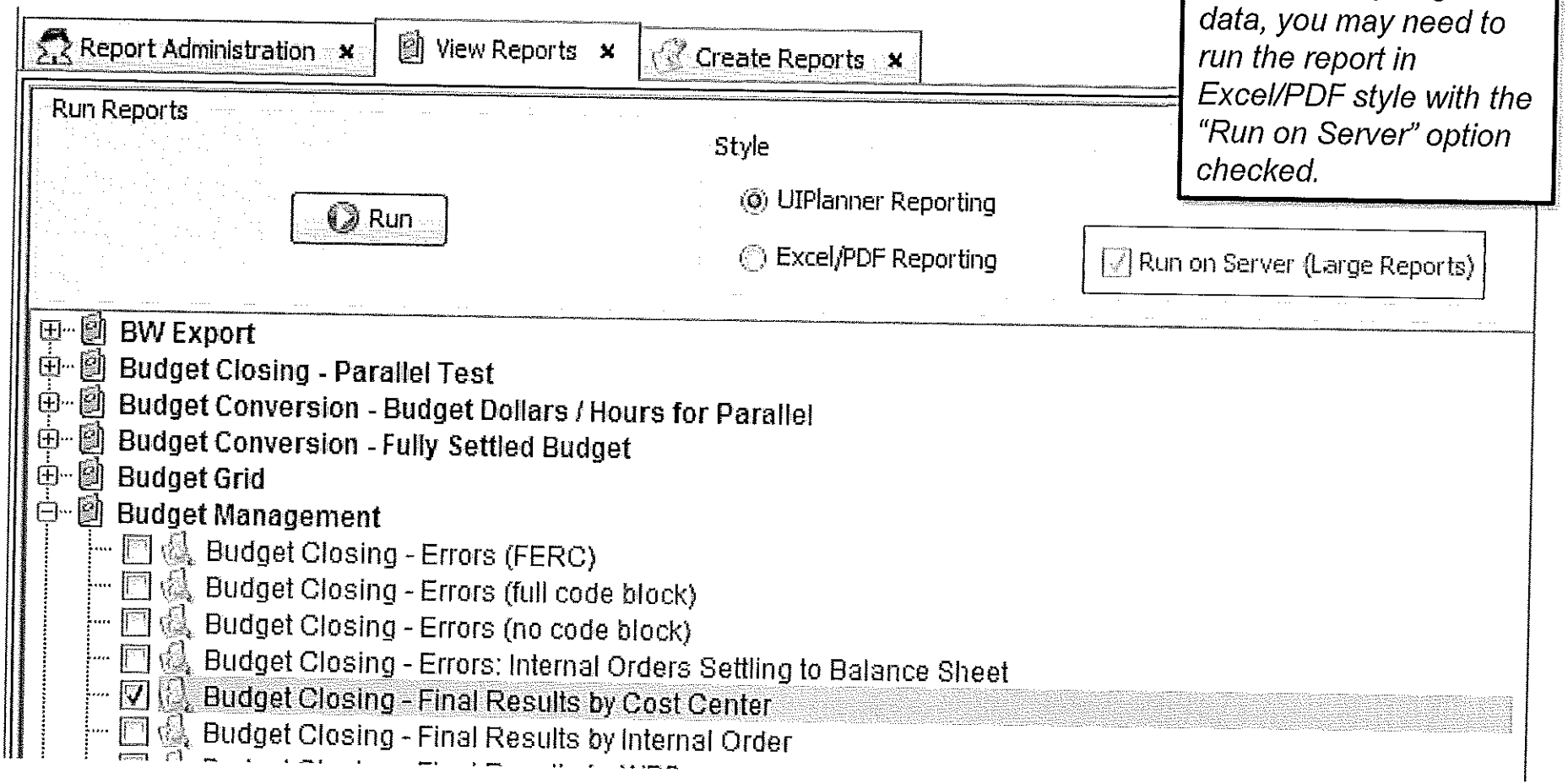


Tip:
Click the downward facing arrow icon next to the "Highlight" button, and select "Unselect All Reports" to de-select previously selected reports.

Running a Report from View Reports Screen

- Select the report style by checking the box next to the report and click Run
- Report Styles:
  - Excel/PDF for printing, saving locally, or if the data is too large.
  - UIPlanner style for the fully featured UIPlanner reporting screen

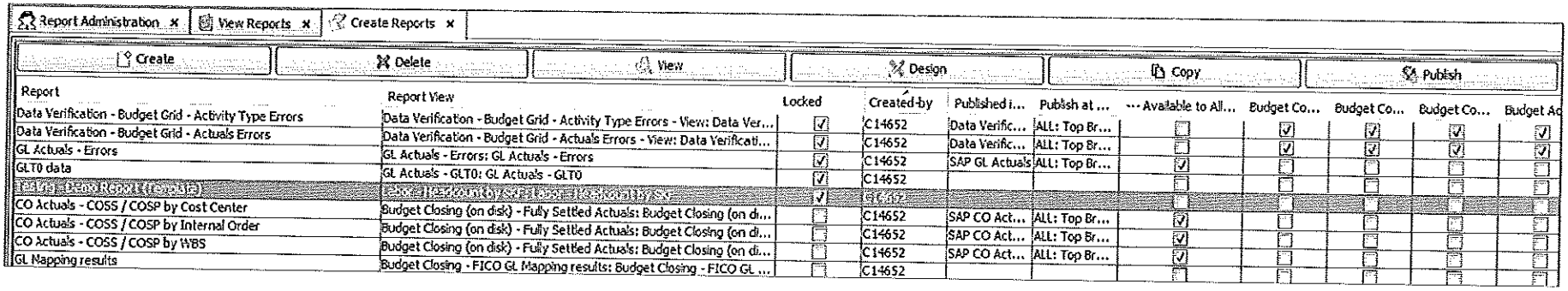
Tip:
For extremely large data, you may need to run the report in Excel/PDF style with the "Run on Server" option checked.



Create Reports Screen

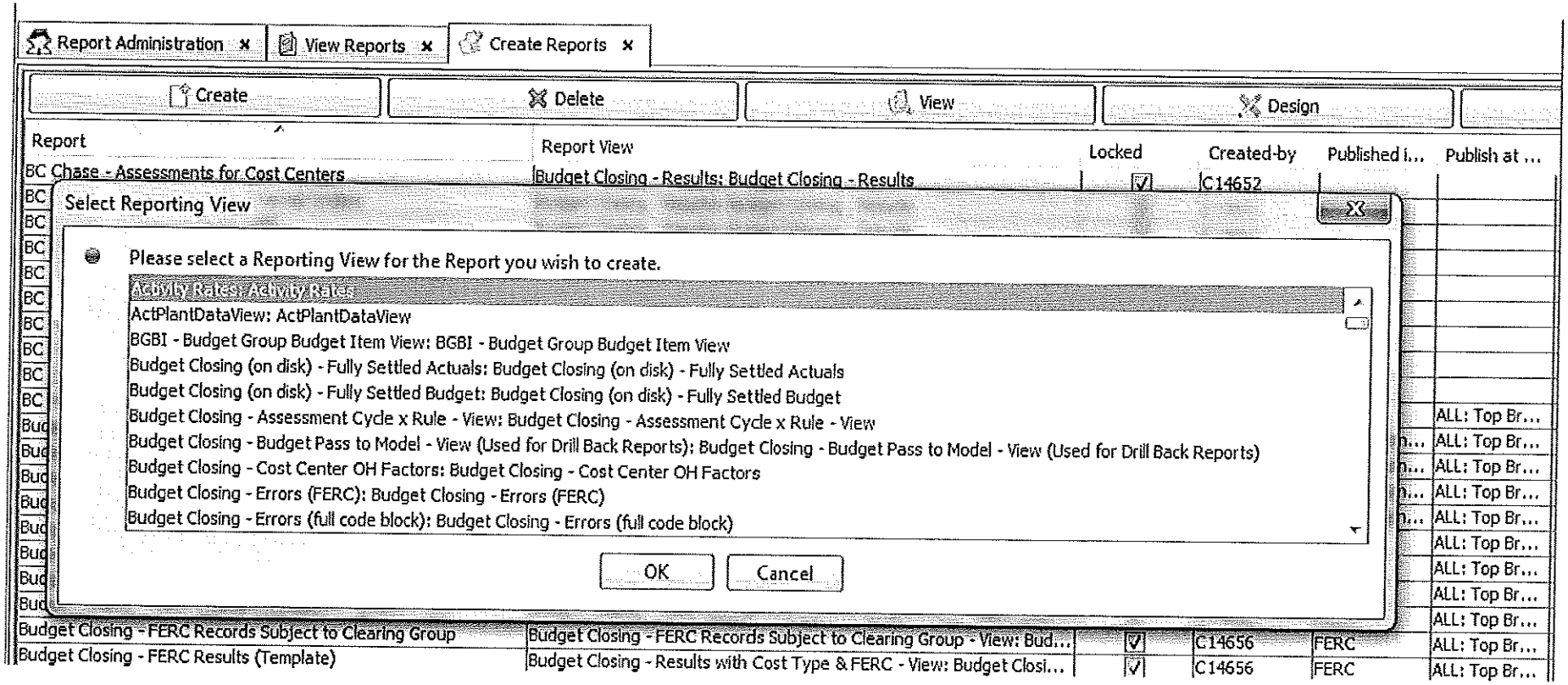
- The Create Reports screen is more flexible than the View Reports screen and allows for greater functionality enabling the user to develop and save versions of reports using these views.
- A Report Administrator can create a View on a set of data and enable features.
- Users can create, delete, view, design, copy, lock, and publish reports to reporting sections by User Role.

Create Reports screen

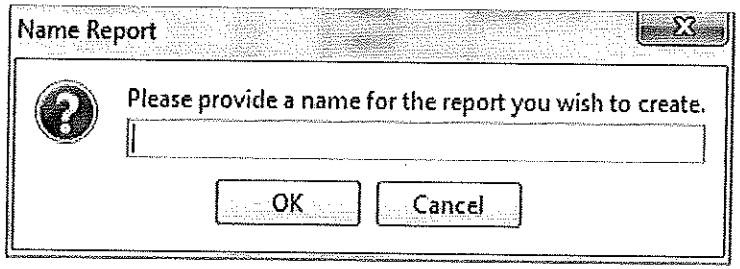


Create Reports Screen – Creating a Report from Scratch

- Click the "Create" button, you will be prompted to select the dataset View on which you wish to build a report.

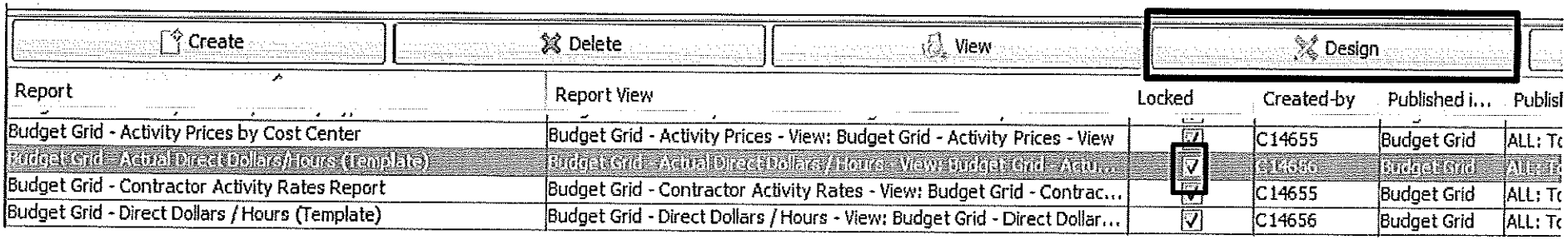


- Give your report a name but pay close attention to the preferred naming conventions to help organize your report.



Create Reports Screen - Creating a Report from a Template

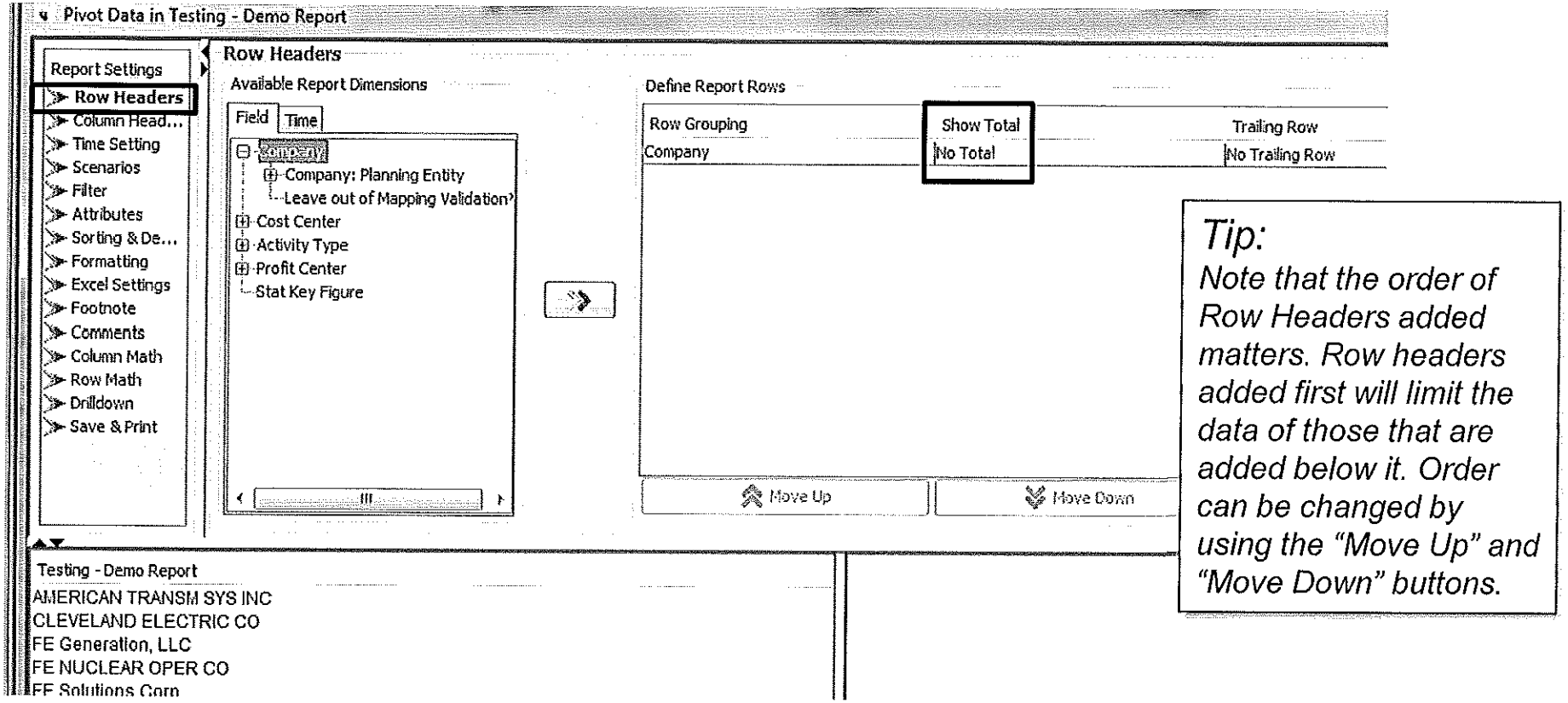
- Select the report from the list on the Create Report screen; should have "(Template)" in the name.
- Note that the Locked checkbox should be checked to prevent someone from accidentally saving their changes to the template itself.
- Press the Design button to bring up the report in design mode, which limits the data being returned to 200 records and allows for faster edits.
- The View button will return ALL records, which can be slow for very large datasets.



Report	Report View	Locked	Created-by	Published i...	Publisl
Budget Grid - Activity Prices by Cost Center	Budget Grid - Activity Prices - View: Budget Grid - Activity Prices - View	☑	C14655	Budget Grid	ALL: Tc
Budget Grid - Actual Direct Dollars/Hours (Template)	Budget Grid - Actual Direct Dollars / Hours - View: Budget Grid - Actu...	☑	C14656	Budget Grid	ALL: Tc
Budget Grid - Contractor Activity Rates Report	Budget Grid - Contractor Activity Rates - View: Budget Grid - Contrac...	☑	C14655	Budget Grid	ALL: Tc
Budget Grid - Direct Dollars / Hours (Template)	Budget Grid - Direct Dollars / Hours - View: Budget Grid - Direct Dollar...	☑	C14656	Budget Grid	ALL: Tc

Create Reports Screen – Adding Row Headers

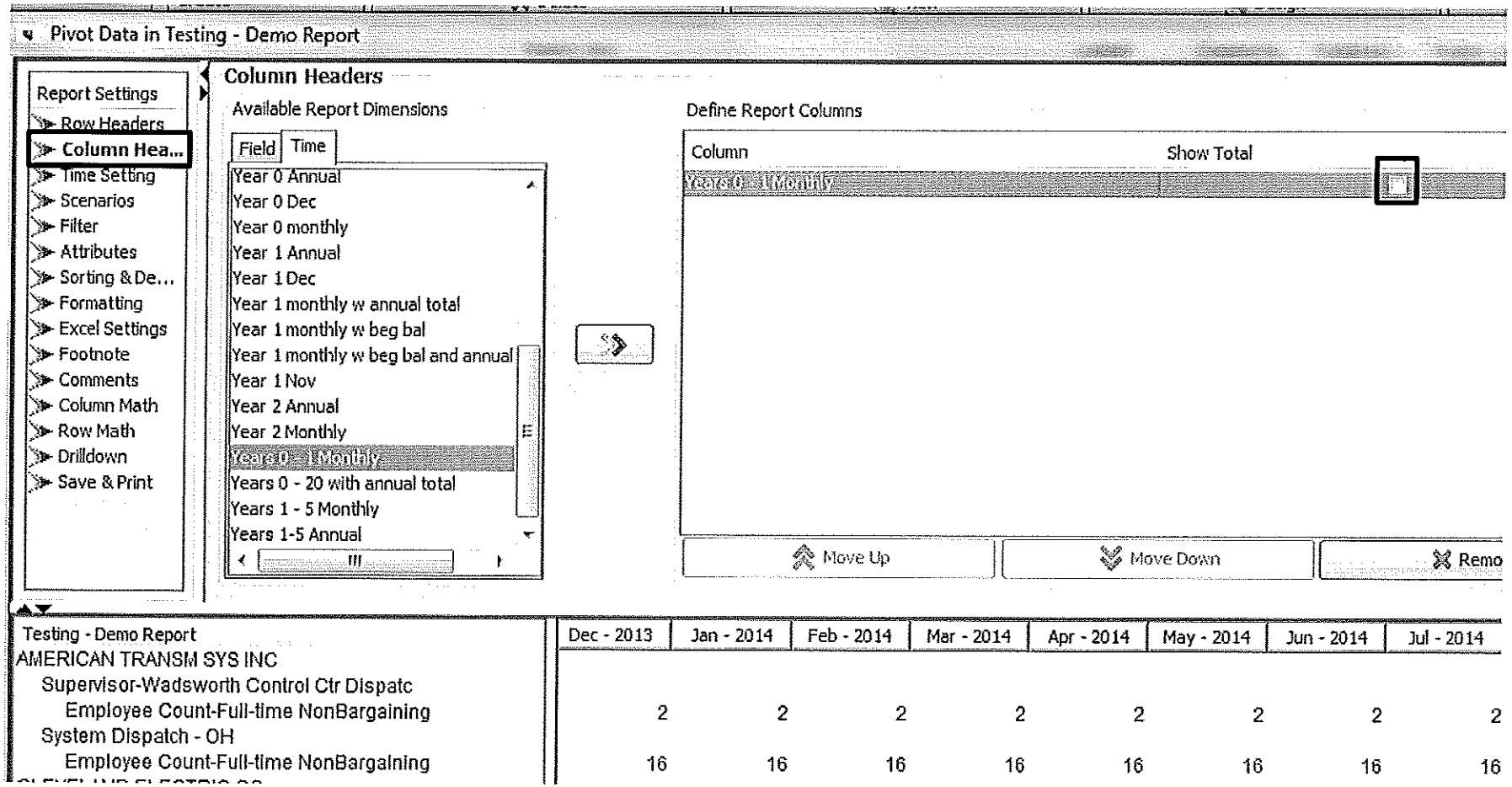
- Select "Row Headers" chevron from the "Report Settings" column to view available fields within the data set view. Highlight the field name and click the Arrow button to add the header to the report.
- You can expand some headers to select a header's attributes to be added. (e.g. Company Planning Entity)
- There is an option to add subtotals and trailing rows to each row added to the report by clicking the text under "Show Total" and "Trailing Row" labels.



Tip:
Note that the order of Row Headers added matters. Row headers added first will limit the data of those that are added below it. Order can be changed by using the "Move Up" and "Move Down" buttons.

Create Reports Screen – Adding Column Headers

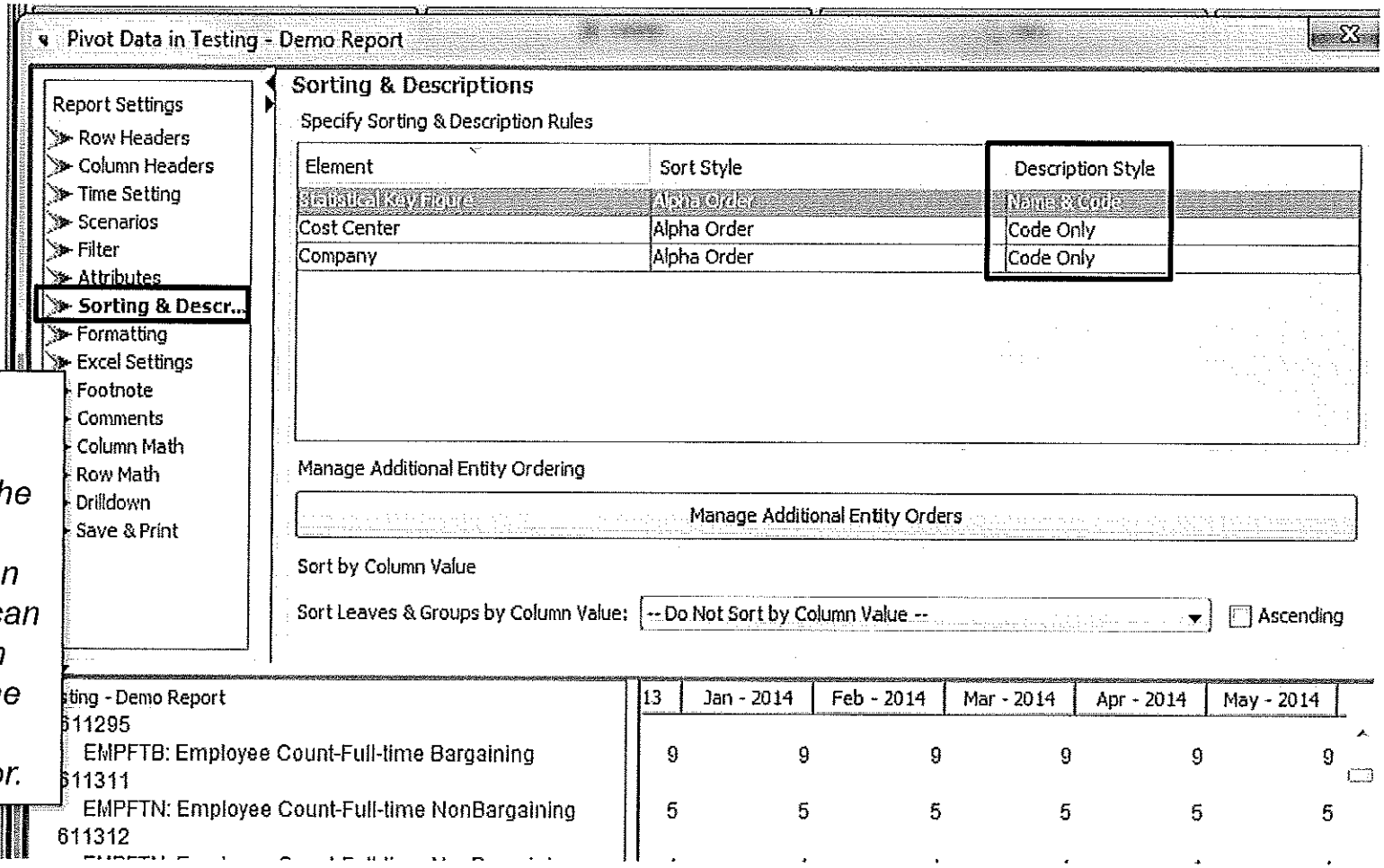
- Add Column Headers to view the time data.
- You can add additional columns to total the time period by checking the "Show Total" box.



Create Reports Screen – Changing Row Value Descriptions

- From the "Sorting and Descriptions" chevron, you can toggle a row header to display the "Name," "Code," or both values. E.g. The company code named "FE Solutions Corp" has a code of 1100, and either or both values can be displayed.

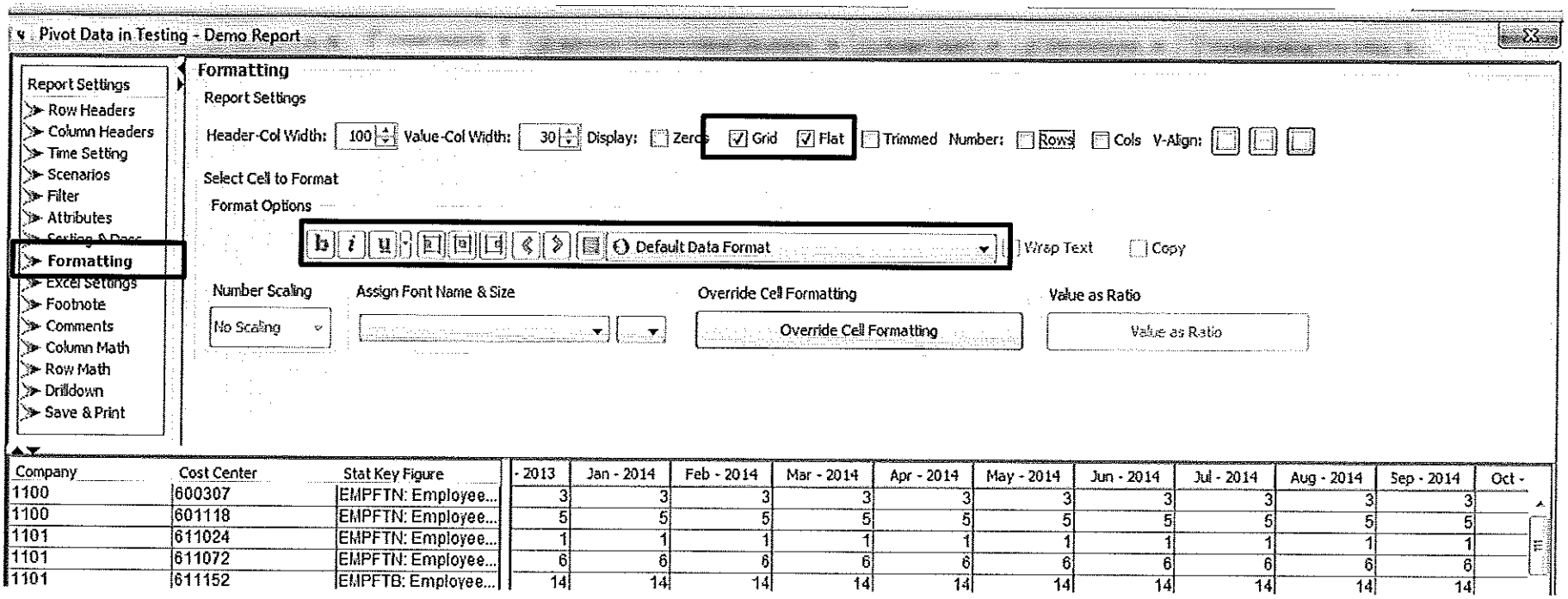
- The Filters in the following section work off of the "Code" values.



Tip:
All of the features in the Report Configuration (chevrons) can be turned on and off by the Report Administrator.

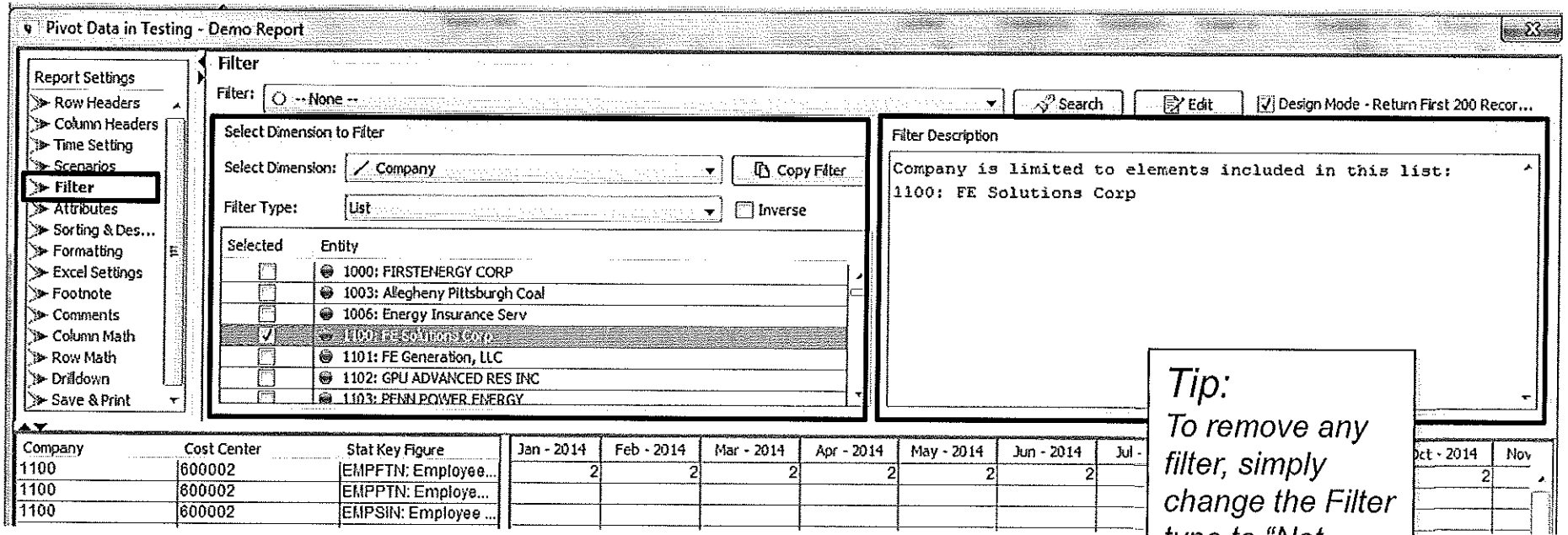
Create Reports Screen – Changing Formatting

- You can change the formatting to add grid lines, flatten out the row headers, etc...
- You can change the level of precision on the time data by clicking on a cell and changing the menu from "Default Data Format" to the desired format.



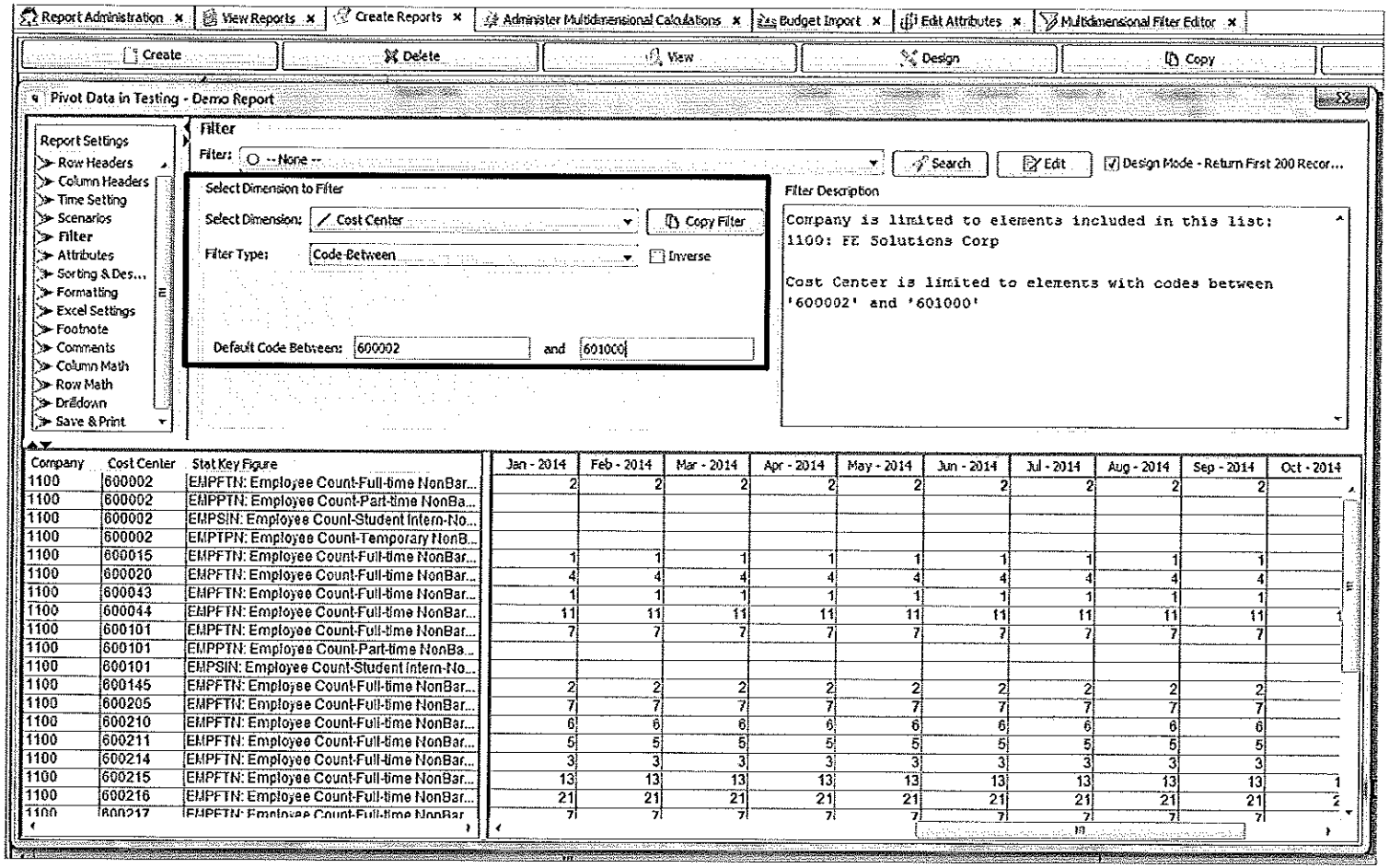
Create Reports Screen – Adding Filters (List Type Example)

- The Filter menu is for selecting Named Filters defined in the "Multidimensional Filter Editor" screen.
- There is a simple filter editor that allows you to select a dimension (one of the row headers) and select a filter type (list, tree, attribute, range, code-between, and code-like).
- The example pictured is an example of a List type filter on Company. Company 1100 is selected from the list and is described in the Filter Description box.



Create Reports Screen – Adding Filters (Code-Between Type Example)

- The example pictured is an example of a Code-Between type filter on Cost Center range. Cost Center Ranges from 600002 to 601000 is filtered.
- Note that the previous Company List type filter is still being applied

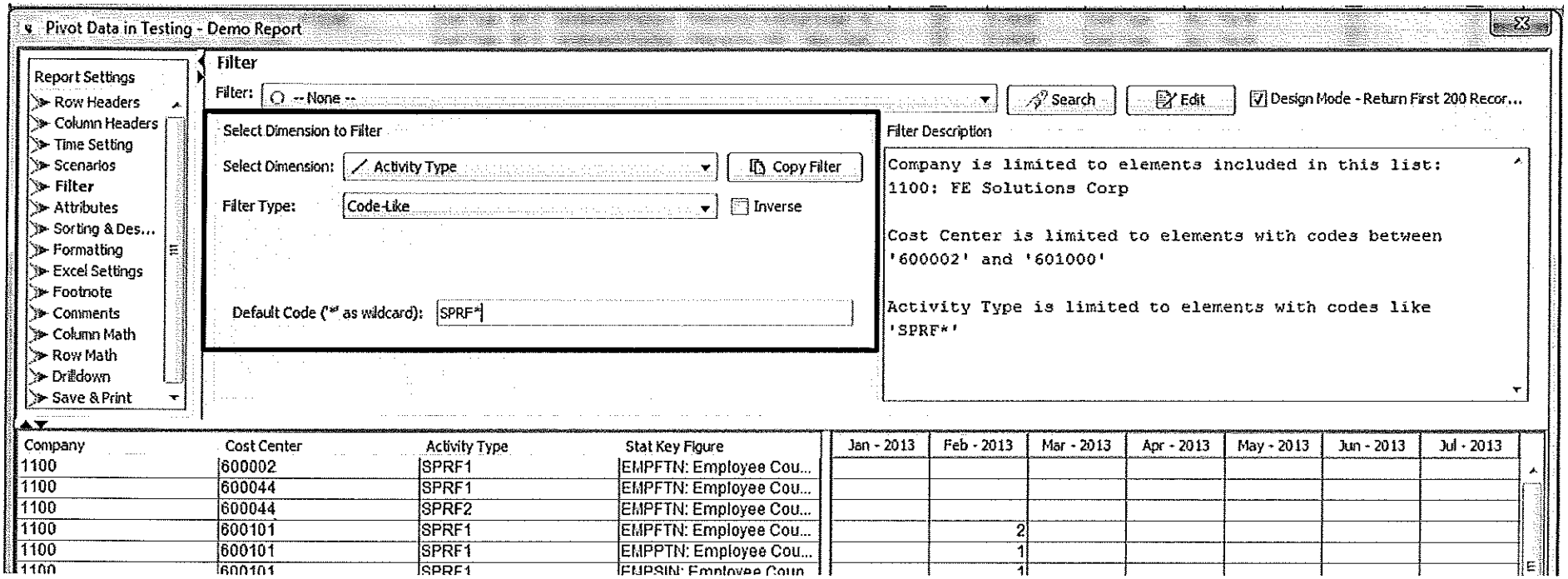


Tip:
The Filter Description window will show which filters are being applied.

Create Reports Screen – Adding Filters (Code-Like Type Example)

- The example pictured is an example of a Code-Like type filter on Activity Type range. Activity Types matching the pattern "SPRF*" are filtered.

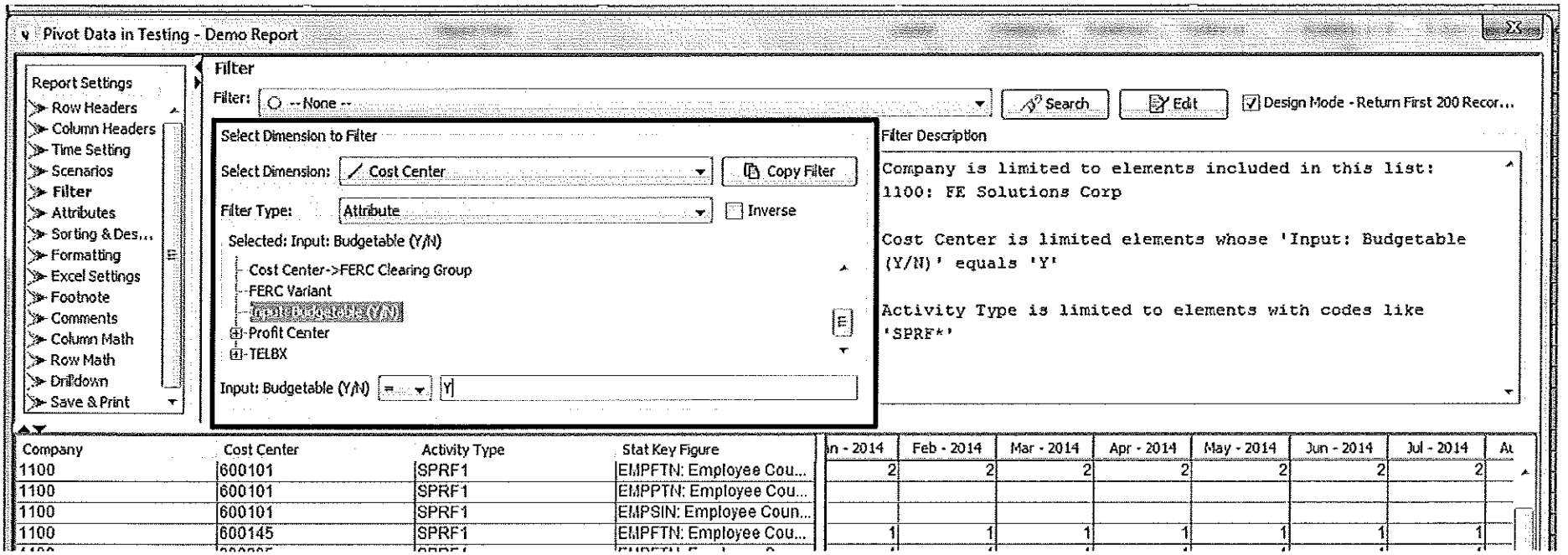
- The wildcard "*" denotes that any characters that <u>follow</u> "SPRF" will match the pattern. "SPRF1" and "SPRF2" match the pattern. "SPFR" would not match nor would "123SPFR" due to the placement of the wildcard character.



Create Reports Screen – Adding Filters (Attribute Type Example)

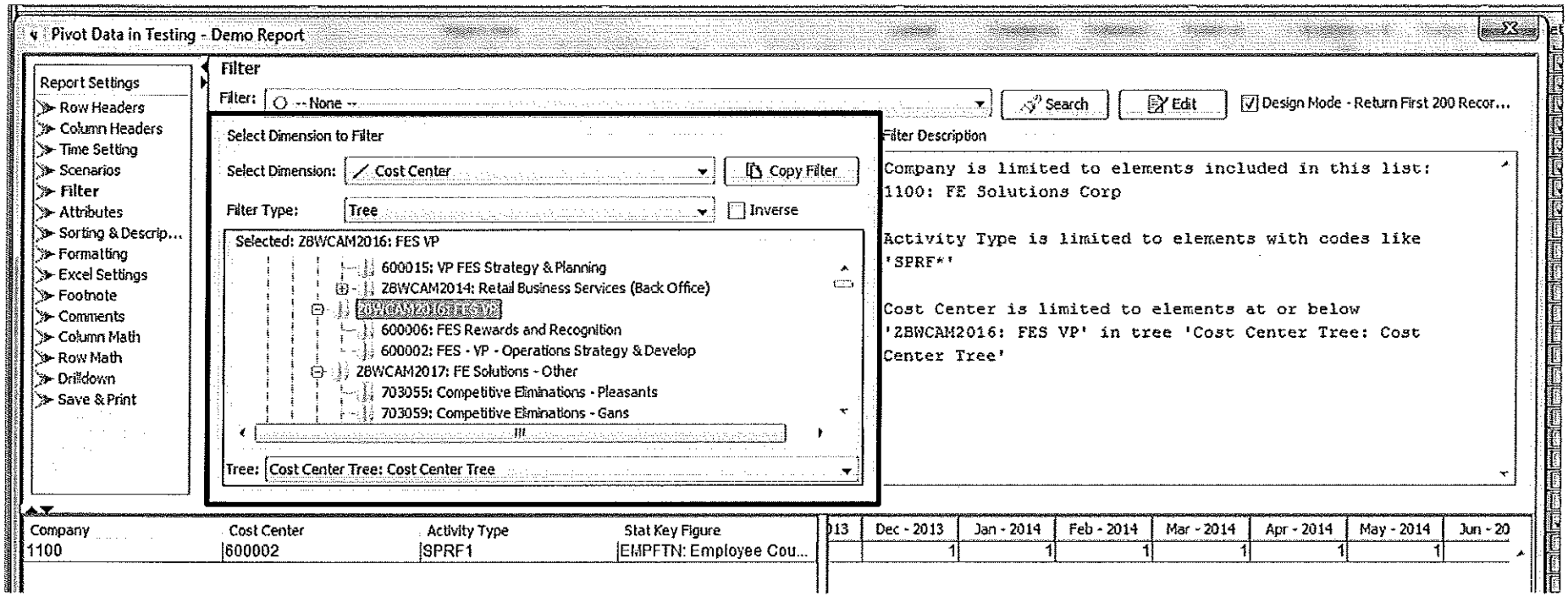
- The example pictured is an example of an Attribute type filter on Cost Center. The filter is checking against the value of the Cost Center's "Budgetable (Y/N)" attribute to only include Cost Centers where this attribute = "Y" It is also possible to use other operators such as >, >=, <, <=, or <> (not equal)

- Note that although the previous filters are still being applied, the Attribute filter on Cost Center has replaced the Cost Center Range type filter.



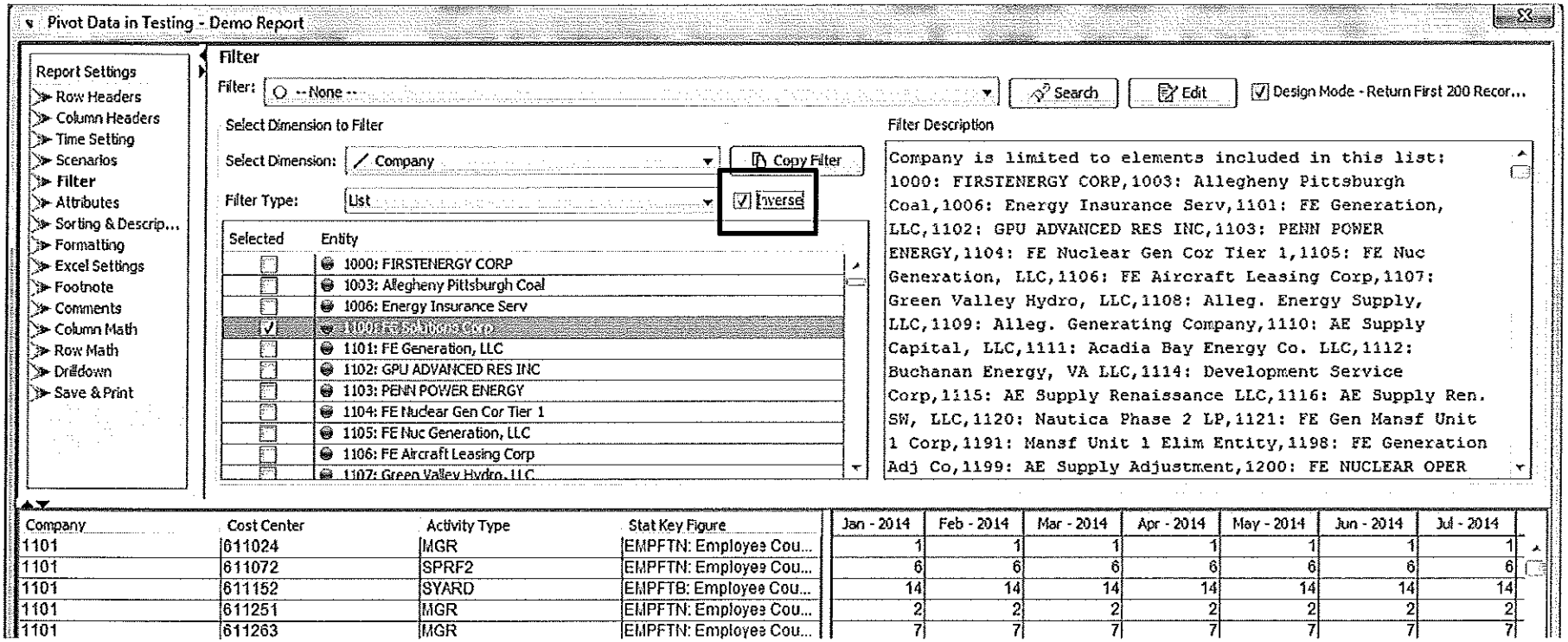
Create Reports Screen – Adding Filters (Tree Type Example)

- Tree filters can only be used on hierarchical elements like Cost Centers. The filter will include any element that appears at or below the selected node on the tree structure.
- Note that although the previous filters are still being applied, the Tree filter on Cost Center has replaced any other Cost Center filters.



Create Reports Screen – Inverse Filters

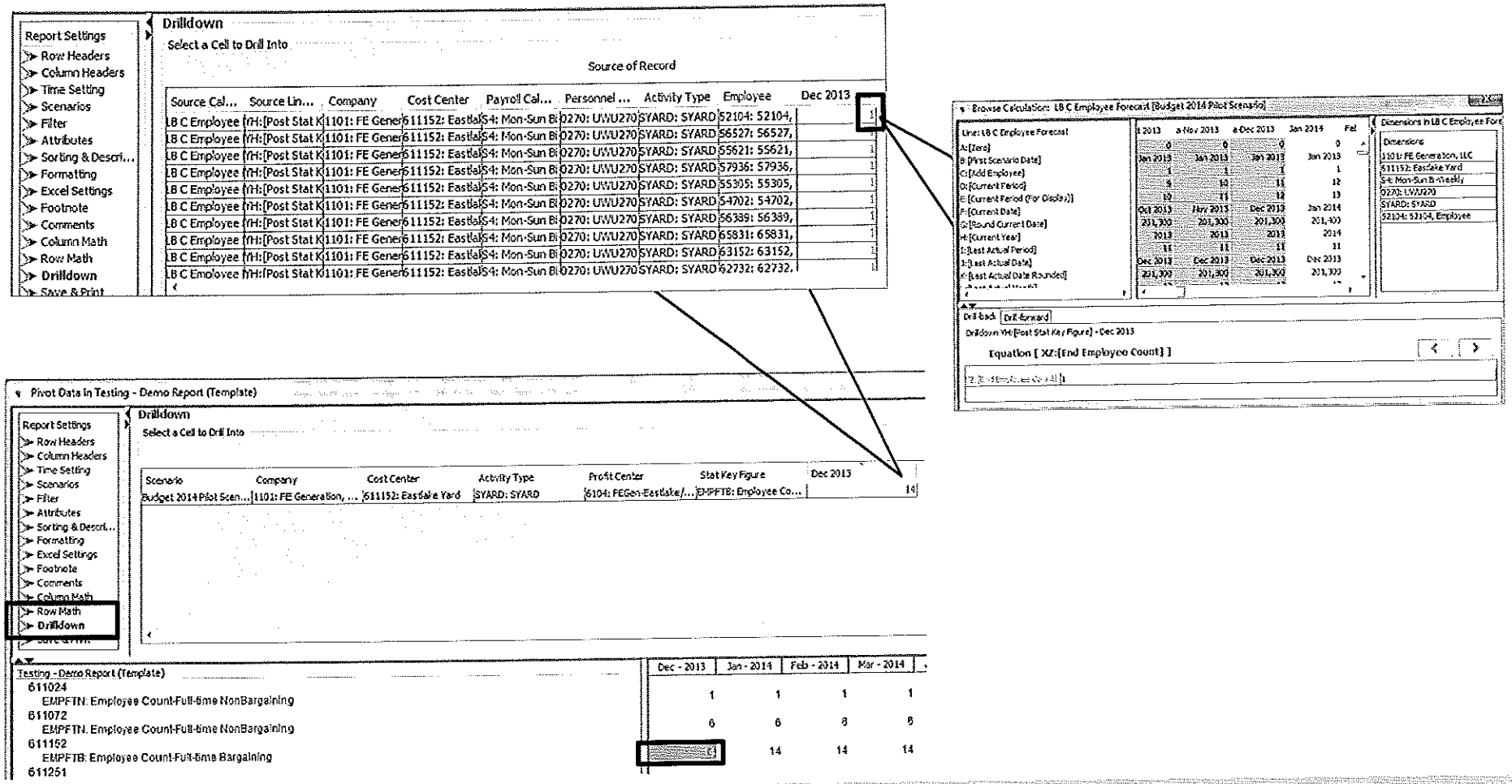
- For any Filter type, you can inverse the filter logic by checking the "Inverse" box. E.g. By inversing a Company List filter type set to "1100 - FE Solutions Corp", the results will include every company in the data set EXCEPT the company selected.



Create Reports Screen – Using Drill Down

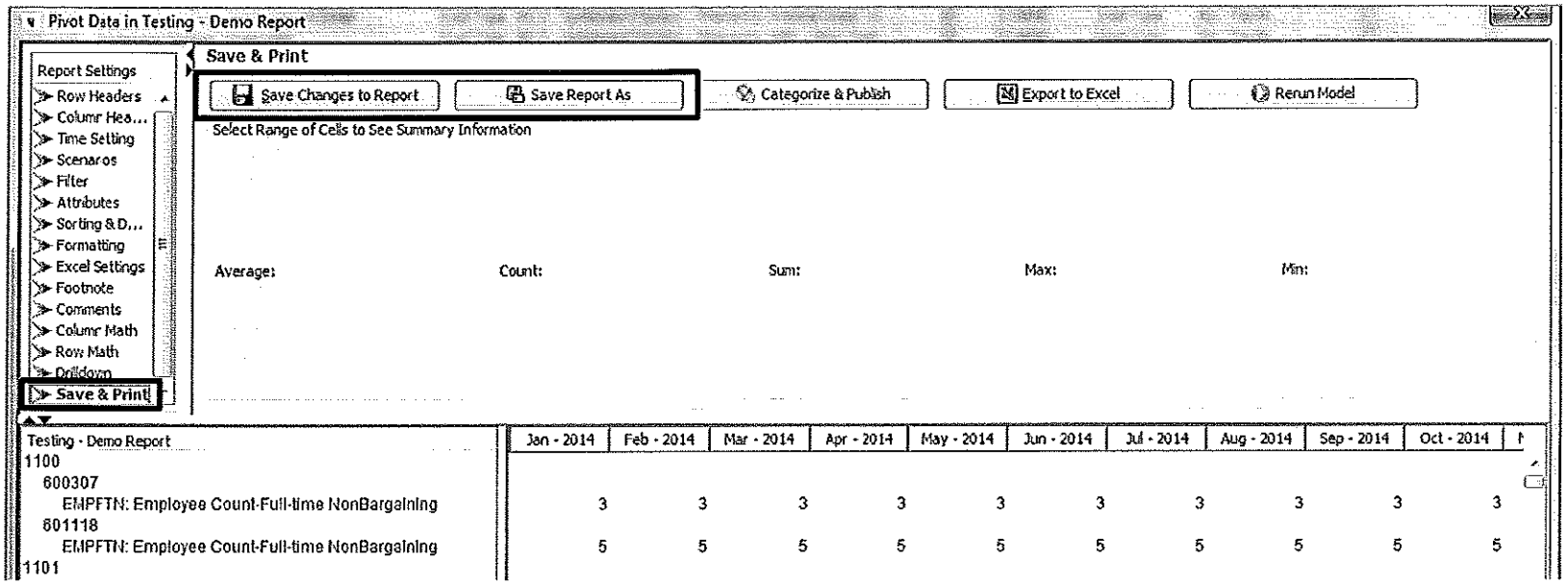
- By selecting the Drill Down chevron, you can drill down into the data and trace the data back to the calculation, formula applied, and constituent data.

- Highlight the data cell and click the linked values to keep drilling back to the data source.

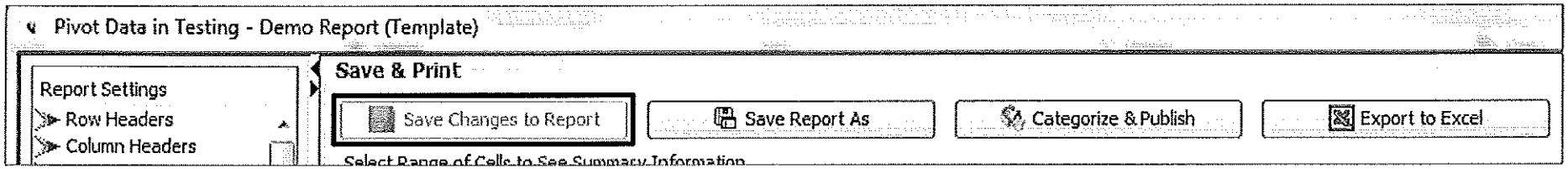


Create Reports Screen – Save and Print Screen

- If you are editing a previously configured report, you can save changes provided that the report is not locked and the "Save" function is enabled by the Report Administrator.



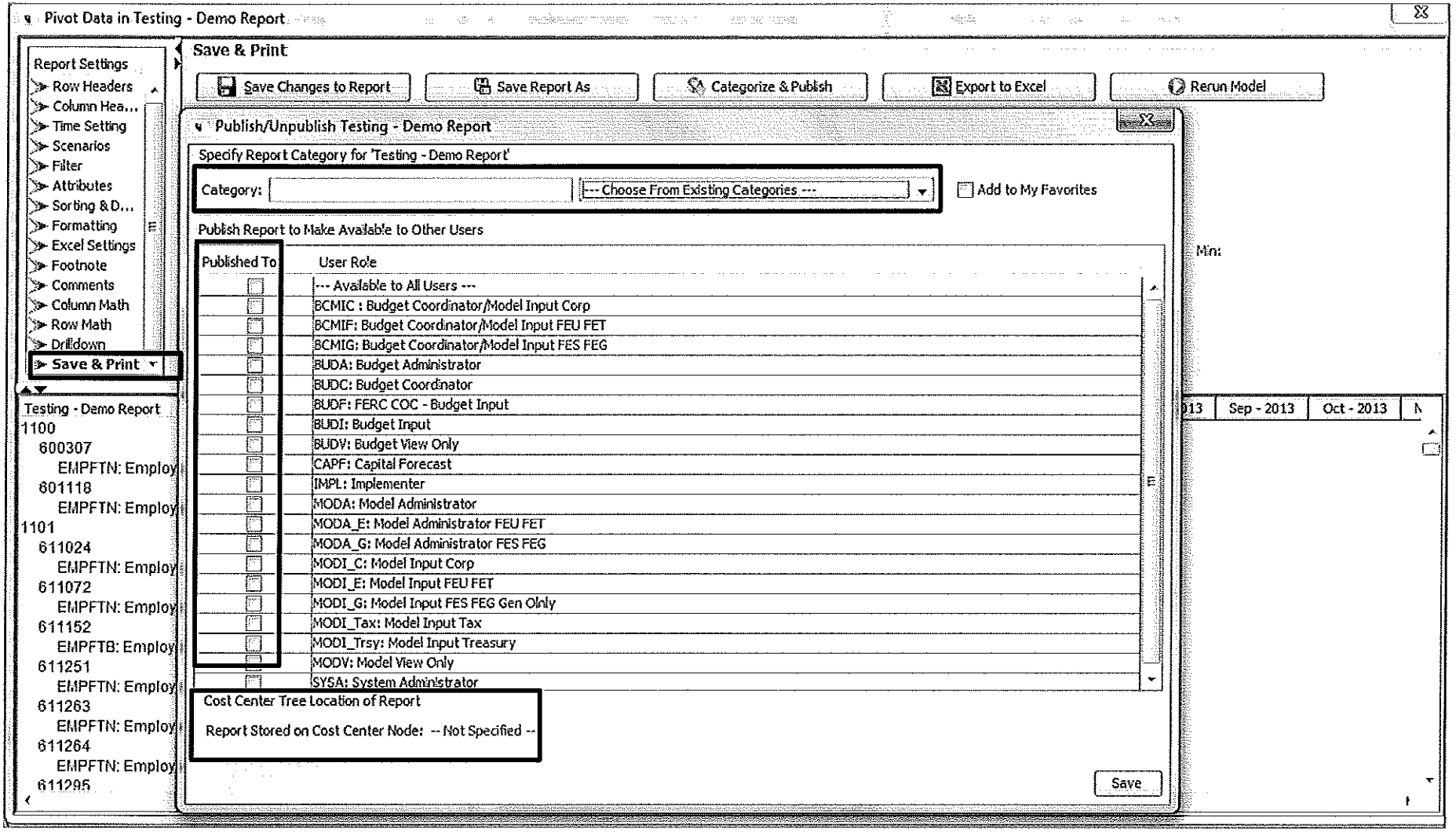
- If you are editing a locked "Template," use the "Save Report As." The "Save" button should be disabled for all Locked reports.



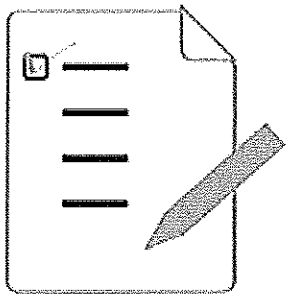
- Some reports will be Read-Only and all Save functionality will be disabled by the Report Administrators.

Create Reports Screen – Publishing Reports

- Push the "Categorize & Publish" button, and select or create a Category.
- Before saving, select the User Role checkboxes that should have access to the report.
- Be aware of your Cost Center Tree Context since your report will inherit it.



Exercise #3 – Reporting

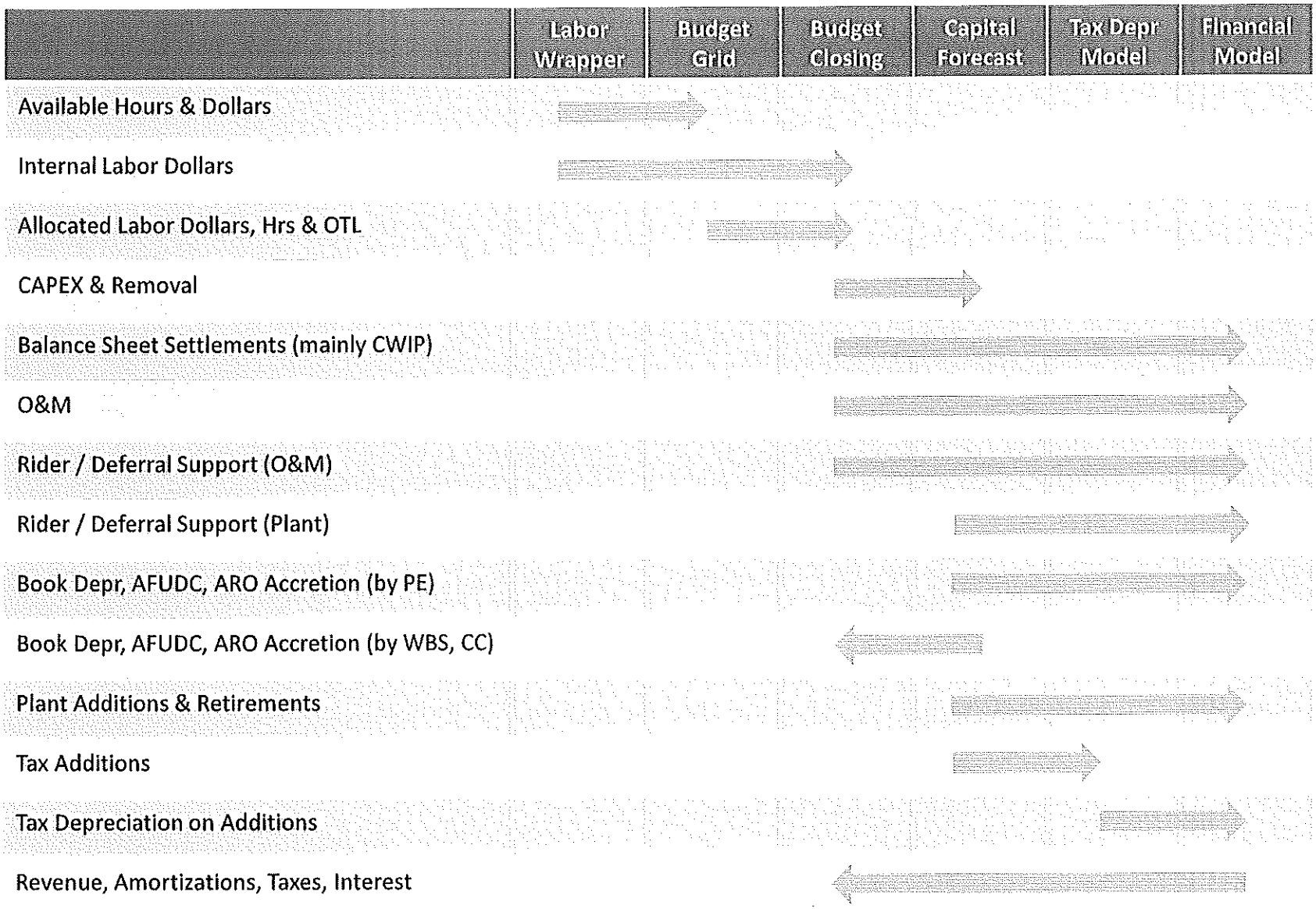


- Select View Reports and a category
  - Run various reports and review the output for selected areas

- Select Create Reports
  - Select dataset view
  - Create report name
  - Select the various reporting chevrons and customize your report
    - Add column headers
    - Change row value descriptions
    - Change formatting
    - Add a filter
    - Publish report

Data Flow

Data Flow

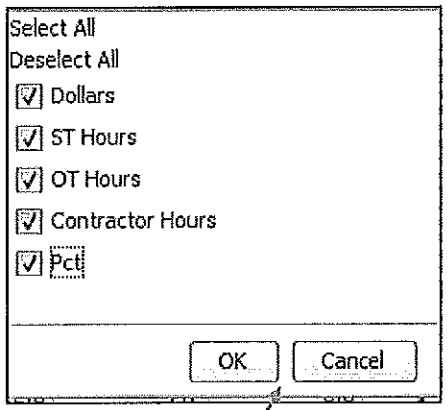

Labor Wrapper
Budget Grid
Budget Closing
Capital Forecast
Tax Depr Model
Financial Model
Available Hours & Dollars
Internal Labor Dollars
Allocated Labor Dollars, Hrs & OTL
CAPEX & Removal
Balance Sheet Settlements (mainly CWIP)
O&M
Rider / Deferral Support (O&M)
Rider / Deferral Support (Plant)
Book Depr, AFUDC, ARO Accretion (by PE)
Book Depr, AFUDC, ARO Accretion (by WBS, CC)
Plant Additions & Retirements
Tax Additions
Tax Depreciation on Additions
Revenue, Amortizations, Taxes, Interest

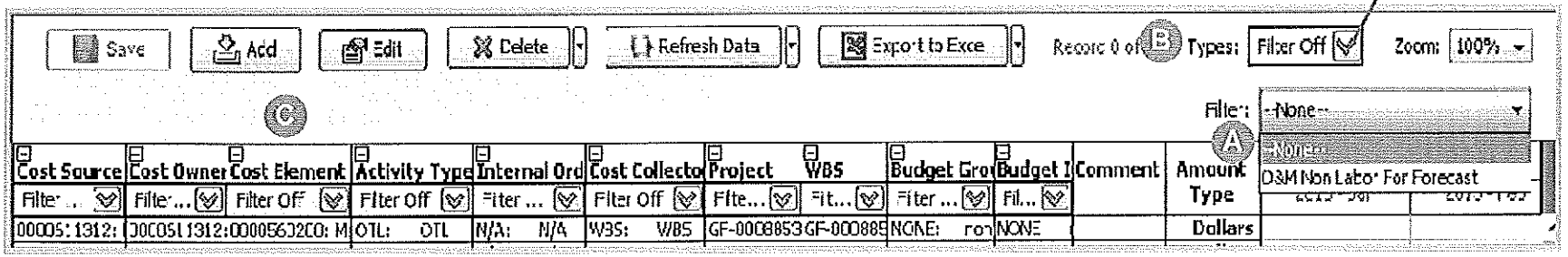
Multi-Year Plan / Forecast

Multi-Year Plan / Forecast Overview

Multi-Year Forecast Requirements

- Ability to properly run the budget close process for years 1-5 (cost collector detail needed for this to occur)
- Allows users the ability to develop a detailed forecast or adjust at a summary level
- Ability for System Administrator to set global assumptions





Filters available to target specific areas to change

A. Filter on common categories (e.g. Cost Element groupings, O&M other than labor, Labor, etc.)
B. Filter on dollars or hours
C. Grid filters for each code block data field (specific Cost Elements, specific Cost Source, etc)

Multi-Year Plan / Forecast Options

Available options to perform multi-year plan/forecast

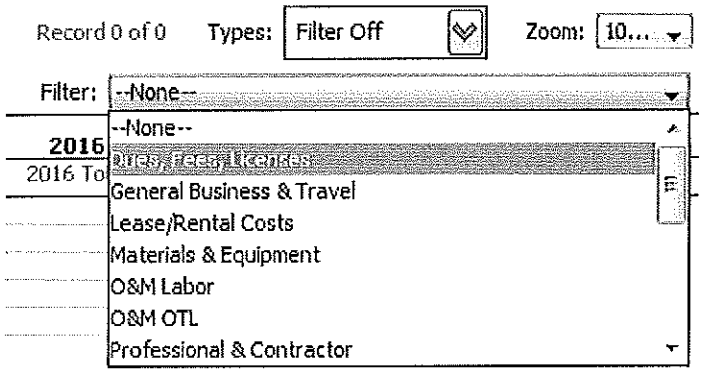
Detailed

- Labor automatically calculates for planning horizon
- Copy current year grid to Excel for entire group or specific Cost Centers (years 1-5)
- Make detailed adjustments at any level in Excel
- Copy data back to grid (grid validates)
- User can then use the "column total" feature in the grid to adjust the forecast

Summary

- Labor automatically calculates for planning horizon
- Utilize available filters
  - Using the cost element hierarchy, users can easily select the cost element node and then make adjustments to the related code block (e.g. O&M non-capital) or create filters based on the income statement groups
- User can then use the "column total" feature in the grid to adjust the forecast

Users can view filters in the Budget Grid by using the drop down to select a group



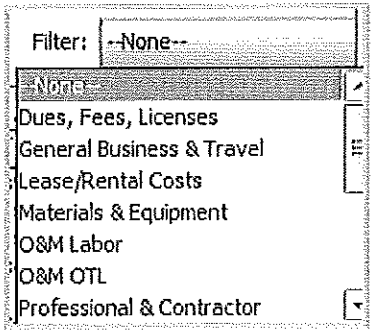
Current and Multi-Year Forecast Filters

Current and Multi-Year Forecast Filters

- Grid filters are available to assist with the current and multi-year forecast process
- Filters utilize various nodes within the internal income statement cost element hierarchy
  - The cost element hierarchy is maintained in SAP
  - Transaction KAH3 – Cost Element Group = ZBWIIS0000
- Additional filters include leveraging attributes on master data
  - Projects and WBS Elements
- When a grid filter is selected, only the data that matches the filter will display
  - Example: Labor – only displays grid combinations that contain labor cost elements



- Budget Grid
  - Select a grid filter
  - Edit on screen or Excel



Available Grid Filters

O&M OTL Filters

- **O&M OTL**
  - ZBWIIS2192
- **Dues, Fees Licenses**
  - ZBWIIS2193
- **General Business & Travel**
  - ZBWIIS2202
- **Lease/Rental Costs**
  - ZBWIIS2198
- **Materials & Equipment**
  - ZBWIIS2214
- **Professional & Contractor**
  - ZBWIIS2220
- **Tree Trimming Total**
  - ZBWIIS2232
- **Uncollectible Expense**
  - ZBWIIS2242

O&M Labor Filter

- **O&M Labor**
  - ZBWIIS2161

Project Filters

Project Definition

Investment Profile

- Project = Mandatory (FE01)
- Project – Maintain (FE02)
- Project = Improve (FE03)
- Project = Value (FE04)

Available Grid Filters

WBS Element Filters

- **Interest Profile = Blanket**

ACCTWO	Blkt Accounting Orders 107345
COMMEQB	Blkt Comm Equipment 107328 / 108529
CORPB	Blkt Corporate Items - Manual Settlement Rules
DATAPRB	Blkt Data Process Equip 107326 / 108532
DLLANDB	Blkt Dist Lines Site & R of W 107343 / 108527
DLOHB	Blkt Dist Lines OH 107314 / 108527
DLUGB	Blkt Dist Lines UG 107315 / 108527
DSTOTHB	Blkt Dist Other 107319 / 108527
DSTSUBB	Blkt Dist Sub 107313 / 108527
ESIPOHB	Blkt Street Lighting ESIP OH 107320 / 108528
ESIPUGB	Blkt Street Lighting ESIP UG 107321 / 108528
GENOTHB	Blkt Other General Plant 107329 / 108529
GENPLTB	Blkt Office Furn,Tools & Test Eq 107323 / 108529
GNLANDB	Blkt General Plant Site & R of W 107344 / 108529
JCOTHB	Blkt Jobbing & Contract Other 186001
JOBCONB	Blkt Jobbing & Contract 186001
MTRTRFB	Blkt Project Meters Only 107318 / 108527
MUTASTB	Blkt Mutual Assistance Storms 186789
NONULB	Blkt Non-Utility Land 121341 / 122302
NONUTFB	Blkt Non-Utility Fiber Optics 121342 / 122303
NONUTLB	Blkt Non-Utility Property 121341 / 122302
NONUTOB	Blkt Non-Utility Other 121341 / 122302
OTHLNDB	Blkt Other Site & R of W GEN ONLY 107339 / 108524
PRDHYDB	Hydro Blanket Proj 107303 / Removal Use Ferc CC
PRDNUCB	Nuclear Blanket Proj 107301 / Removal Use Ferc CC
PRDOTHB	Peaker Blanket Proj 107302 / Removal Use Ferc CC
PRDSTMB	Steam Fossil Blanket Proj 107300 / Removal Use Fe
PSIB	Blkt Preliminary Survey & Investigation 183000
PWROPER	Blkt Power Operated Equipment 107325 / 108531
SLOHB	Blkt Street Lighting Overhead 107316 / 108527
SLUGB	Blkt Street Lighting Underground 107317 / 108527
STRUCTB	Blkt Buildings & Related Projects 107322 / 108529
SUBBLLB	Blkt Billings to Subsidiaries 186415
TEMPB	Blkt Temporary Facilities 185000
TL138B	Blkt Transmission Lines 138KV 107308 / 108526
TL23KVB	Blkt Transmission Lines 23KV 107305 / 108526
TL34KVB	Blkt Transmission Lines 34KV 107306 / 108526
TL69KVB	Blkt Transmission Lines 69KV 107307 / 108526
TLLANDB	Blkt Trans Lines Site & R of W 107341 / 108526
TLO115B	Blkt Project TX OH Lines 115KV 107000 / 108000
TLO11B	Blkt Project TX OH Lines 11.8KV 107000 / 108000
TLO13B	Blkt Project TX OH Lines 13.8KV 107000 / 108000
TLO230B	Blkt Project TX OH Lines 230KV 107000 / 108000
TLO25B	Blkt Project TX OH Lines 25KV 107000 / 108000
TLO345B	Blkt Project TX OH Lines 345KV 107000 / 108000
TLO36B	Blkt Project TX OH Lines 36KV 107000 / 108000
TLO46B	Blkt Project TX OH Lines 46KV 107000 / 108000
TLO500B	Blkt Project TX OH Lines 500KV 107000 / 108000
TLO765B	Blkt Project TX OH Lines 765KV 107000 / 108000
TLOTHB	Blkt Transmission Lines Other 107311 / 108526
TLU115B	Blkt Project TX URD Lines 115KV 107000 / 108000
TLU11B	Blkt Project TX URD Lines 11.8KV 107000 / 108000
TLU138B	Blkt Project TX URD Lines 138KV 107000 / 108000
TLU13B	Blkt Project TX URD Lines 13.8KV 107000 / 108000
TLU230B	Blkt Project TX URD Lines 230KV 107000 / 108000
TLU23B	Blkt Project TX URD Lines 23KV 107000 / 108000
TLU25B	Blkt Project TX URD Lines 25KV 107000 / 108000
TLU345B	Blkt Project TX URD Lines 345KV 107000 / 108000
TLU34B	Blkt Project TX URD Lines 34KV 107000 / 108000
TLU36B	Blkt Project TX URD Lines 36KV 107000 / 108000
TLU46B	Blkt Project TX URD Lines 46KV 107000 / 108000
TLU500B	Blkt Project TX URD Lines 500KV 107000 / 108000
TLU69B	Blkt Project TX URD Lines 69KV 107000 / 108000
TLU765B	Blkt Project TX URD Lines 765KV 107000 / 108000
TLUGB	Blkt Trans Lines UG <69KV 107310 / 108526
TRANSB	Blkt Transportation Equipment 107324 / 108530
TRANSFB	Blkt Project Transformers Only 107318 / 108527
TRANUGB	Blkt Trans Lines UG <69KV 107310 / 108526
TRNSUBB	Blkt Transmission Substations 107304 / 108526
GENPLOM	GENERAL PLANT OPERATIONS % MAINTENANCE

Available Grid Filters

WBS Element Filters

- **Interest Profile = Program**

COMMEQP	Prgm Comm Equipment 107328 / 108529
DLLANDP	Prgm Dist Lines Site & R of W 107343 / 108527
DLOHP	Prgm Dist Lines OH 107314 / 108527
DLUGP	Prgm Dist Lines UG 107315 / 108527
DSTOTHP	Prgm Dist Other 107319 / 108527
DSTSUBP	Prgm Dist Sub 107313 / 108527
ESIPOHP	Prgm Street Lighting ESIP OH 107320 / 108528
ESIPUGP	Prgm Street Lighting ESIP UG 107321 / 108528
GENOTHP	Prgm Other General Plant 107329 / 108529
GNLANDP	Prgm General Plant Site & R of W 107344 / 108529
MTRTRFP	Prgm Project Meters Only 107318 / 108527
SLOHP	Prgm Street Lighting Overhead 107316 / 108527
SLUGP	Prgm Street Lighting Underground 107317 / 108527
TEMPP	Prgm Temporary Facilities 185000
TL23KVP	Prgm Transmission Lines 23KV 107305 / 108526
TL34KVP	Prgm Transmission Lines 34KV 107306 / 108526
TL69KVP	Prgm Transmission Lines 69KV 107307 / 108526
TLLANDP	Prgm Trans Lines Site & R of W 107341 / 108526
TLOTHP	Prgm Transmission Lines Other 107311 / 108526
TLUGP	Prgm Trans Lines UG <69KV 107310 / 108526
TRANSFP	Prgm Project Transformers Only 107318 / 108527
TRANSP	Prgm Transportation Equipment 107324 / 108530
TRANUGP	Prgm Trans Lines UG <69KV 107310 / 108526
TRNSUBP	Prgm Transmission Substations 107304 / 108526

Available Grid Filters

WBS Element Filters

- **Interest Profile = Specific**

INTANG	Intangible Plant 107346
TXOMOH	Trans O&M - Overhead Lines 563 / 571
BLGLEAS	Spc Leased Bldg & Related Equip 107327 / 108529
COMMEQS	Spc Comm Equipment 107328 / 108529
CORPS	Spc Corporate Items - Manual Settlement Rules
DATAPRS	Spc Data Process Equip 107326 / 108532
DEFSTMS	Spc New Jersey Storm Deferral 182316
DLLANDS	Spc Dist Lines Site & R of W 107343 / 108527
DLOHS	Spc Dist Lines OH 107314 / 108527
DLUGS	Spc Dist Lines UG 107315 / 108527
DSLANDS	Spc Dist Sub Site & R of W 107342 / 108527
DSTOTHS	Spc Dist Other 107319 / 108527
DSTSUBS	Spc Dist Sub 107313 / 108527
ESIPOHS	Spc Street Lighting ESIP OH 107320 / 108528
ESIPUGS	Spc Street Lighting ESIP UG 107321 / 108528
GENOTHS	Spc Other General Plant 107329 / 108529
GNLANDS	Spc General Plant Site & R of W 107344 / 108529
JCOTHS	Spc Jobbing & Contract Other 186001
JOBCONS	Spc Jobbing & Contract 186001
MTRTRFS	Spc Project Meters Only 107318 / 108527
MUTASTS	Spc Mutual Assistance Storms 186789
NFLEAS	Spc Nuclear Fuel Capital Lease 120600
NONULS	Spc Non-Utility Land 121341 / 122302
NONUTFS	Spc Non-Utility Fiber Optics 121342 / 122303
NONUTLS	Spc Non-Utility Property 121341 / 122302
NONUTOS	Spc Non-Utility Other 121341 / 122302
NUCFLS	Spc Nuclear Fuel 120100
NUCLDS	Spc Nuclear Site & R of W 107338 / 108523
OTHLNDS	Spc Other Site & R of W GEN ONLY 107339 / 108524
PRDHYDS	Hydro Specific Proj 107303 / Removal Use Ferc CC
PRDNUCS	Nuclear Specific Proj 107301 / Removal Use Ferc CC
PRDOTHS	Peaker Specific Proj 107302 / Removal Use Ferc CC
PRDSTMS	Steam Fossil Specific Proj 107300 / Removal Use Fe
PSI	Spc Preliminary Survey & Investigation 183000
REASDEV	Spc Research & Development 188000
SLOHS	Spc Street Lighting Overhead 107316 / 108527
SLUGS	Spc Street Lighting Underground 107317 / 108527
STMLNDS	Spc Fossil Site & R of W 107337 / 108522
STRUCTS	Spc Buildings & Related Projects 107322 / 108529
SUBBLLS	Spc Billings to Subsidiaries 186415
TEMPS	Spc Temporary Facilities 185000
TL138S	Spc Transmission Lines 138KV 107308 / 108526
TL230S	Spc Transmission Lines 230KV 107347 / 108526
TL23KVS	Spc Transmission Lines 23KV 107305 / 108526
TL345S	Spc Transmission Lines 345KV 107309 / 108526
TL34KVS	Spc Transmission Lines 34KV 107306 / 108526
TL500S	Spc Transmission Lines 500KV 107348 / 108526
TL69KVS	Spc Transmission Lines 69KV 107307 / 108526
TLLANDS	Spc Trans Lines Site & R of W 107341 / 108526
TLO115S	Spc Project TX OH Lines 115KV 107000 / 108000
TLO11S	Spc Project TX OH Lines 11.8KV 107000 / 108000
TLO13S	Spc Project TX OH Lines 13.8KV 107000 / 108000
TLO25S	Spc Project TX OH Lines 25KV 107000 / 108000
TLO36S	Spc Project TX OH Lines 36KV 107000 / 108000
TLO46S	Spc Project TX OH Lines 46KV 107000 / 108000
TLO765S	Spc Project TX OH Lines 765KV 107000 / 108000
TLOTHS	Spc Transmission Lines Other 107311 / 108526
TLU115S	Spc Project TX URD Lines 115KV 107000 / 108000
TLU11S	Spc Project TX URD Lines 11.8KV 107000 / 108000
TLU138S	Spc Project TX URD Lines 138KV 107000 / 108000
TLU13S	Spc Project TX URD Lines 13.8KV 107000 / 108000
TLU230S	Spc Project TX URD Lines 230KV 107000 / 108000
TLU23S	Spc Project TX URD Lines 23KV 107000 / 108000
TLU25S	Spc Project TX URD Lines 25KV 107000 / 108000
TLU345S	Spc Project TX URD Lines 345KV 107000 / 108000
TLU34S	Spc Project TX URD Lines 34KV 107000 / 108000
TLU36S	Spc Project TX URD Lines 36KV 107000 / 108000
TLU46S	Spc Project TX URD Lines 46KV 107000 / 108000
TLU500S	Spc Project TX URD Lines 500KV 107000 / 108000
TLU69S	Spc Project TX URD Lines 69KV 107000 / 108000
TLU765S	Spc Project TX URD Lines 765KV 107000 / 108000
TLUGS	Spc Trans Lines UG <69KV 107310 / 108526
TRANSFS	Spc Project Transformers Only 107318 / 108527
TRANUGS	Spc Trans Lines UG <69KV 107310 / 108526
TRLANDS	Spc Trans Sub Site & R of W 107340 / 108526
TRNSUBS	Spc Transmission Substations 107304 / 108526

Available Grid Filters

WBS Element Filters

- **Interest Profile = Other**

DXOMMIC	Dist O&M - Misc Exps 588 / 598
DXOMMTR	Dist O&M - Meter Exps 586 / 597
DXOMOH	Dist O&M - Overhead Lines 583 / 593
DXOMSTL	Dist O&M - Street Lighting 585 / 596
DXOMSUB	Dist O&M - Substation 582 / 592
DXOMURD	Dist O&M - Underground Lines 584 / 594
DXOMXFM	Dist O&M - Overhead Transformers 583 / 595
INDA&G	Undist Const Overheads - Admin & General 107334
INDENG	Undist Const Overheads - Engineering 107335
INDSH	Undist Const Overheads - Stores Handling 107330
INDSUPV	Undist Const Overheads - Supervision 107332
INDTRAN	Undist Const Overheads - Transportation 107331
PRDHYDO	Hydro O&M Proj SETTLE TO COST CENTERS ONLY
PRDNUCO	Nuclear O&M Proj SETTLE TO COST CENTERS ONLY
PRDOTHO	Peaker O&M Proj SETTLE TO COST CENTERS ONLY
PRDSTMO	Steam Fossil O&M Proj SETTLE TO COST CENTERS ONLY
PRDSUBS	All Gen Trans Subst 107304 / Removal Use Ferc CC
TOTPRJ	Total Project Place Holder Only
TXOMMIS	Trans O&M - Misc Exps 566 / 573
TXOMSUB	Trans O&M - Substation 562 / 570
TXOMURD	Trans O&M - Underground Lines 564 / 572

Roles and Responsibilities

Roles and Responsibilities

HRIS – (B2) 1

- Create HR information file for interface

IBP – (B2) 2

- Create scenario/cases
- Maintenance of hierarchy trees
- Monitoring/validation of UIPlanner interfaces (on-demand)
  - Master data
  - Companies
  - Power Plant

Business Services / Planning & Anaysis / Operations – (B2) 3

- Input controlled and assigned labor (overtime), OTL and Capital dollars into UIP
- Labor pool validation

General Acct (PA) – (B2) 4

- Update of costing sheets (OH)
- Create cost center assessments, variants and cycles

IBP – (B2) 5

- Application of overheads
- Execution of settlements (Plan vs. Actual)
- Update variants in UIP (provided by GA-PA)
- Execution of assessments
- Run data validation reports
- Run financial reports
- Execution of FERC process
- Run FERC derivation validation reports

FEU Long Term Planning – (Model) 6

- Run Rider/Deferral reports
- Validate results and review with Acctg.

Property Accounting – (Model) 7

- Powerplant interface validation
- Existing plant depreciation calculation validation
- Existing plant AFUDC calculation validation
- Plant addition depreciation/AFUDC calculation validation

Treasury – Debt/Interest (Model) 8

- Update debt transactions, debt amortizations and reacquired debt projections

Tax Planning (Model) 9

- Validation of apportionment factor interface
- Unitary tax calculation validation
- Schedule M item confirmation
- Existing and additions tax depreciation and deferred tax calculation validation
- Tax sharing agreements

Roles and Responsibilities – Labor Planning

- Labor pool preparation – gross payroll, unproductive/productive hours and activity pricing will be developed within UIPlanner
- Finalize labor pool – shift differentials, headcount adjustments
- Labor pool validation – balance labor among capital and cost center, lock budget node

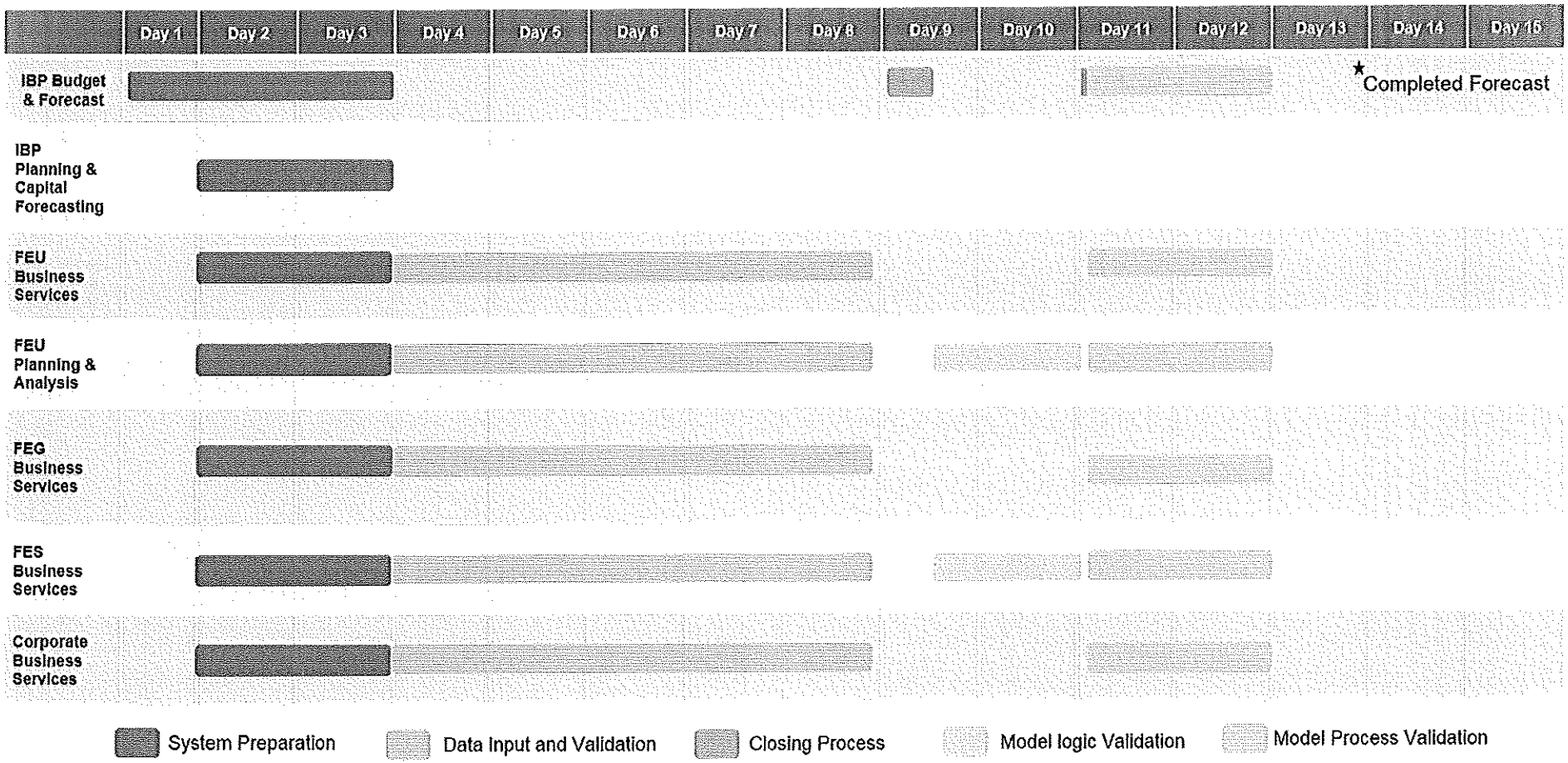
	Labor Pool Prep	Finalize Labor Pool	Develop & Enter Labor for Cost Center	Develop Labor for to Blankets	Enter Labor for Blankets	Develop Labor for Specifics & Programs	Enter Labor for Specifics & Programs	Final Labor Pool Validation
UI Planner	FES, FEG FEU/ FET Corp							
Business Services		FES, FEG FEU/ FET Corp	FES, FEG FEU / FET Corp	FEU/FET	FEU/FET	FEG, Corp, FES, FEU/FET	FEG, Corp	FES, FEG FEU/FET Corp
Operations							FES, FEU/FET	

Roles and Responsibilities – OTL Planning

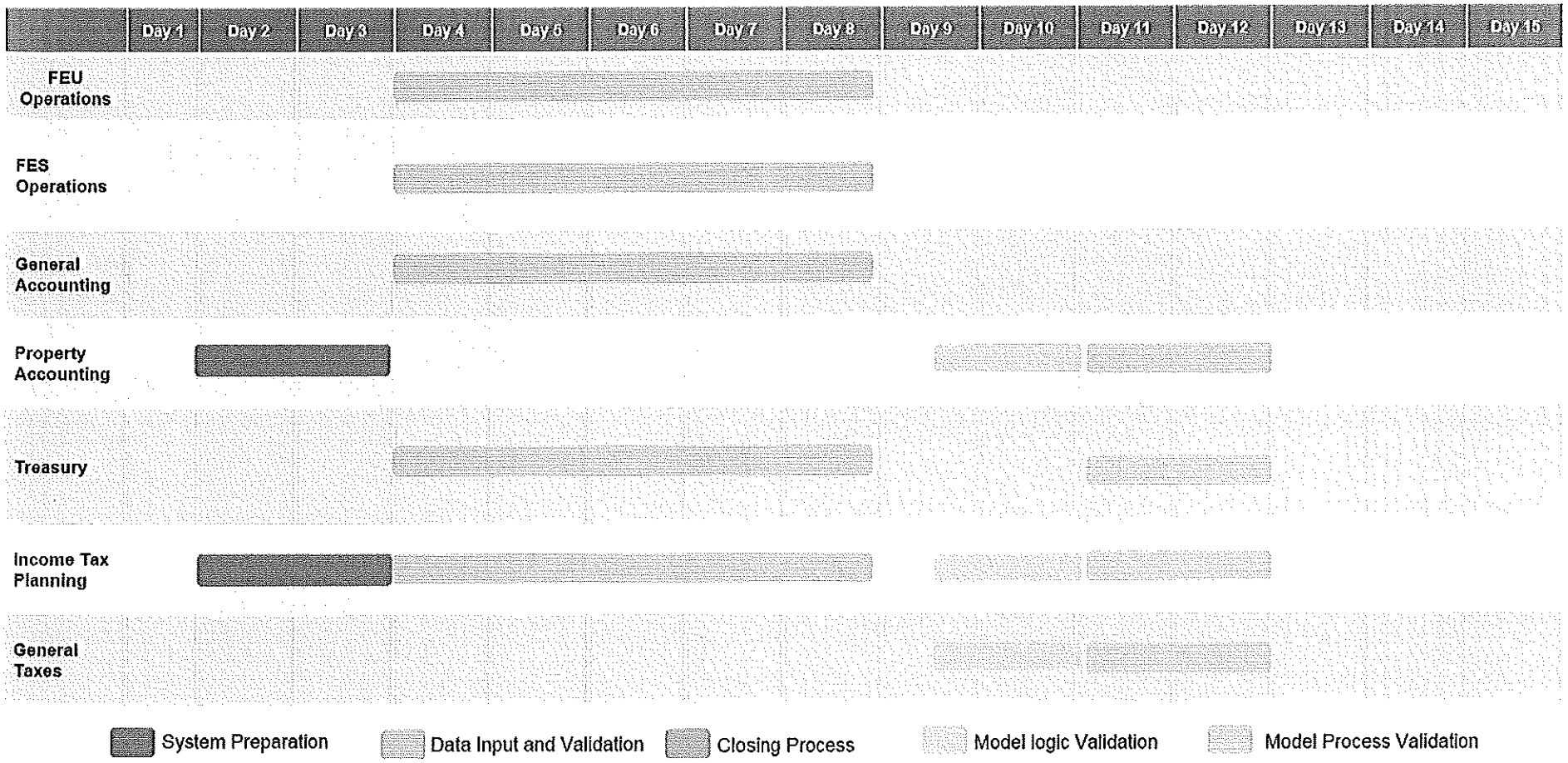
- Reference – users will review previous forecast and actual data within UIPlanner to aid in the development of current forecast
- Development and Validation – users will utilize budget templates or UIPlanner directly for creating and executing reports to ensure data is correctly entered

	Reference Actuals / Prior Forecasts	Develop and Enter Cost Center OTL	Develop Blankets & Outage OTL	Enter Blankets & Outage OTL	Develop Specific & Program OTL	Enter Specific & Program OTL	Final OTL Validation
UI Planner	FES, FEG FEU / FET Corp						
Business Services		FES, FEG, FEU/FET, Corp	FES, FEG FEU / FET	FES, FEG, FEU/FET	FES, FEG, FEU/FET, Corp	FES, FEG, FEU/FET, Corp	FES, FEG FEU / FET Corp
Operations						FEU / FET	

UIP Work Flow Schedule



UIP Work Flow Schedule

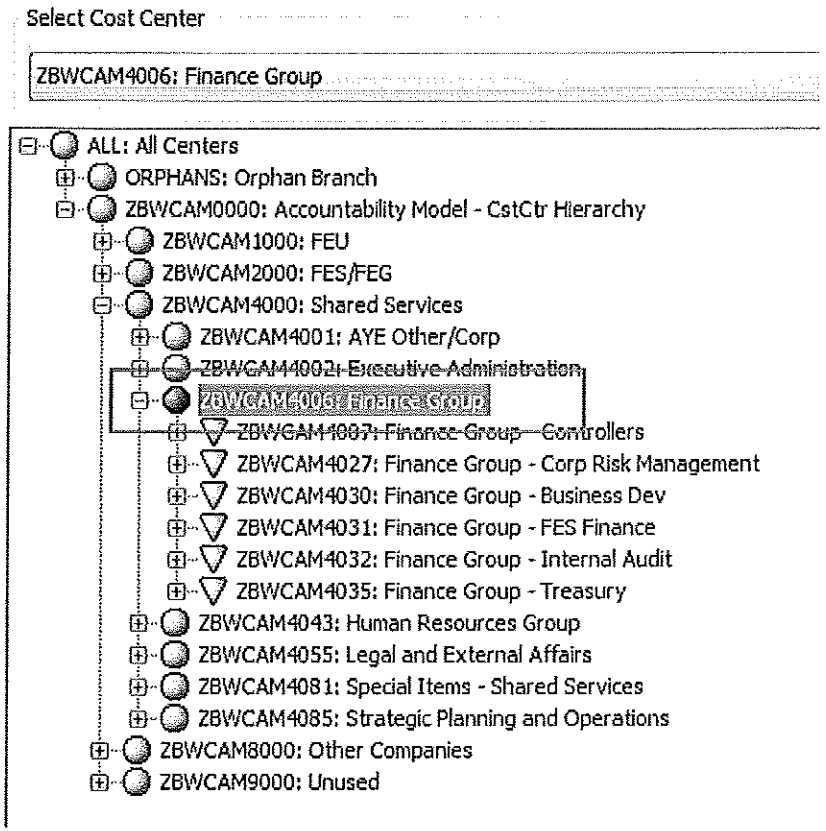


Cost Center Locking

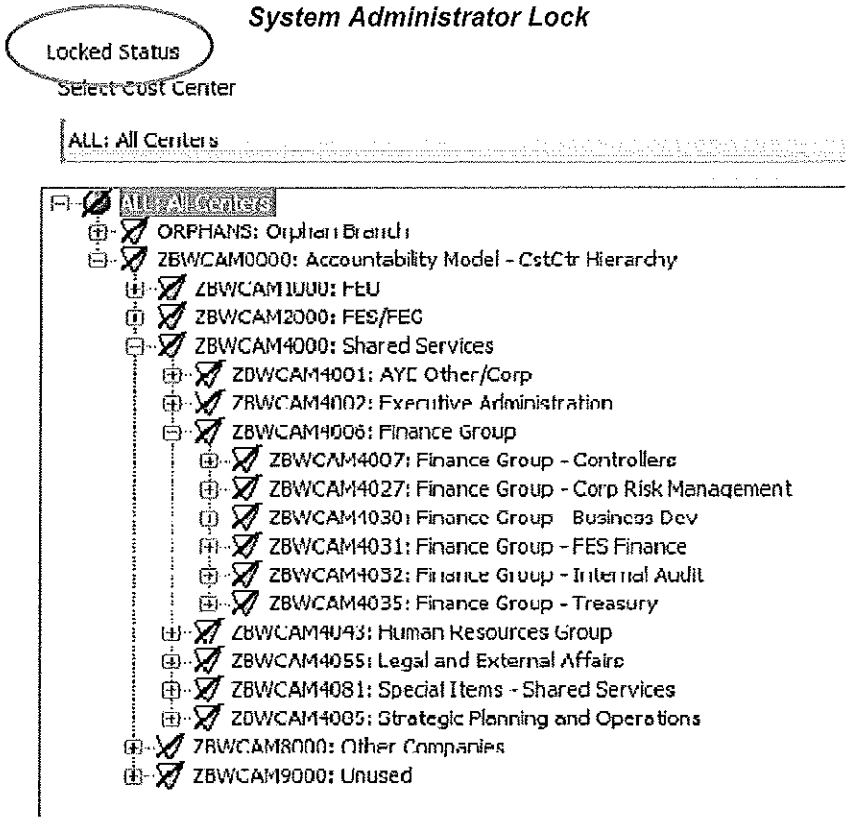
Cost Center Locking Overview

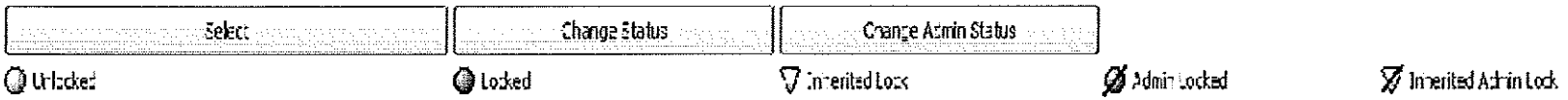
- Budget Administrators can lock their cost centers prior to system processing
- Cost Center locking will serve as part of the budget, forecast and plan approval process
- System Administrator can view user status and perform a global cost center lock
- Cost Center locking also prevents users from entering data to the grid

Budget Owner/Budget Administrator Lock



System Administrator Lock

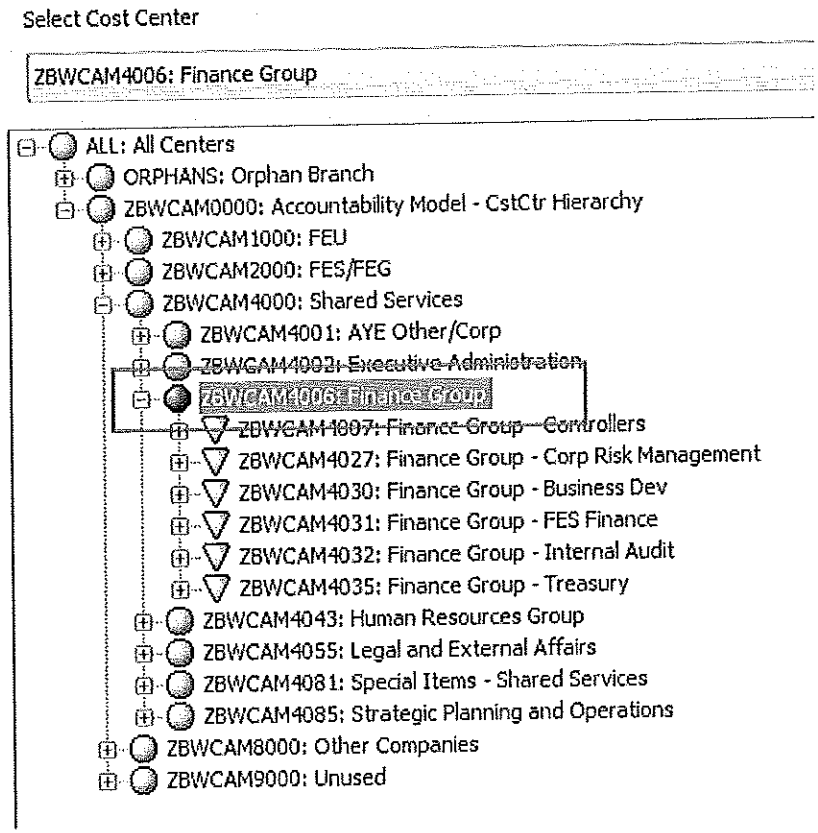


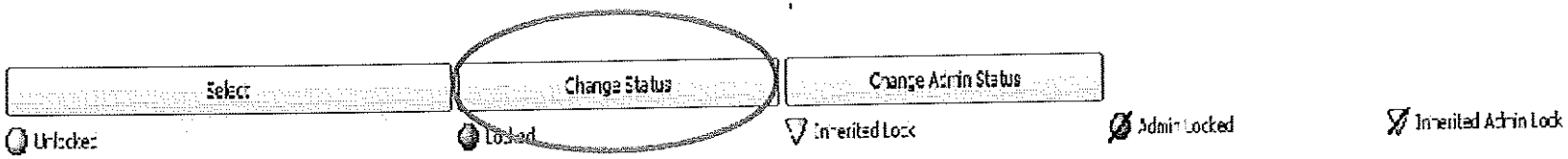


Cost Center Locking

1. Highlight the cost center or cost center node you want to lock
2. Click **Change Status** button on bottom of screen
3. The selected group will lock at the node level (red circle) and perform an inherit lock for all cost centers under that node. Click **Change Status** again to unlock
4. Cost center locking can also be done at the individual cost center level
5. WHEN TRAINING, PLEASE DO NOT LEAVE ANY COST CENTERS LOCKED

Budget Coordinator Lock





Cost Center Locking

- The System Administrator will have the ability to lock the entire system (scenario). This action would typically be done once the budget or forecast is ready to close and process

- Highlight the cost center or cost center node you want to lock

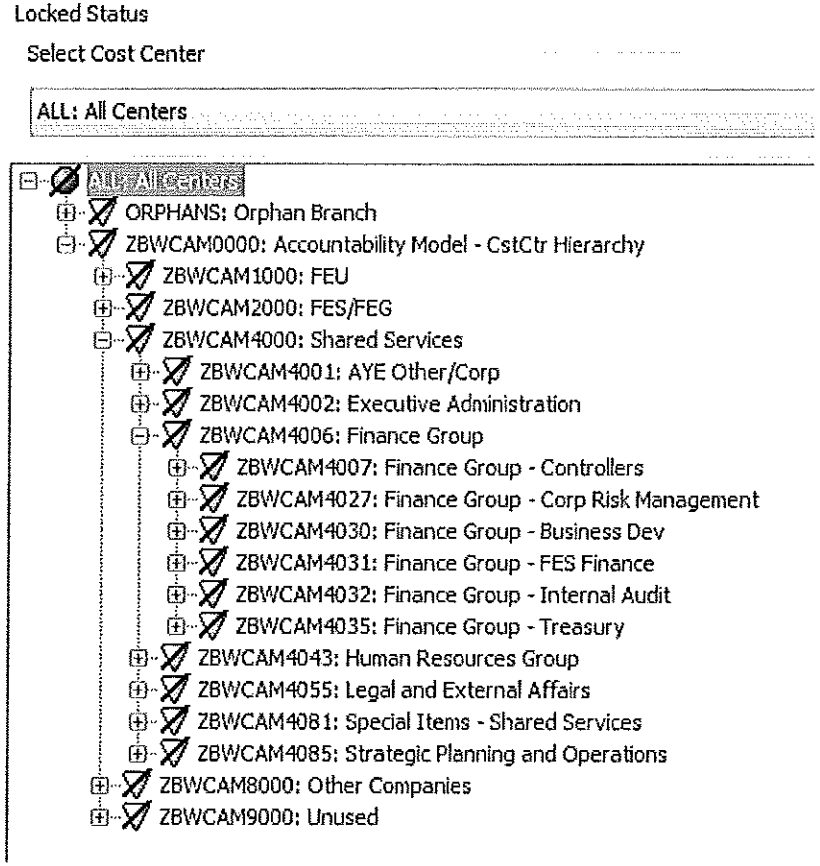
- Click **Change Admin Status** button on bottom of screen. A strike will be appear across the circle and triangles. Click **Change Admin Status** again to unlock

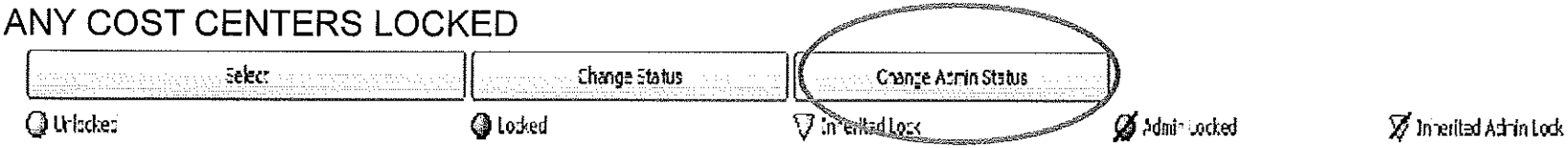
- The selected group will lock at the node level (red circle) and perform an inherit lock for all cost centers under that node. Cost center admin locking can also be done at the individual cost center level

- Your security level may not allow you to do a system lock

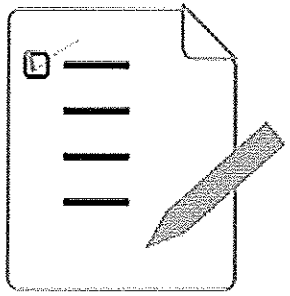
- WHEN TRAINING, PLEASE DO NOT LEAVE ANY COST CENTERS LOCKED

System Administrator Lock





Exercise #4 – Browse Cost Center and Center Locking

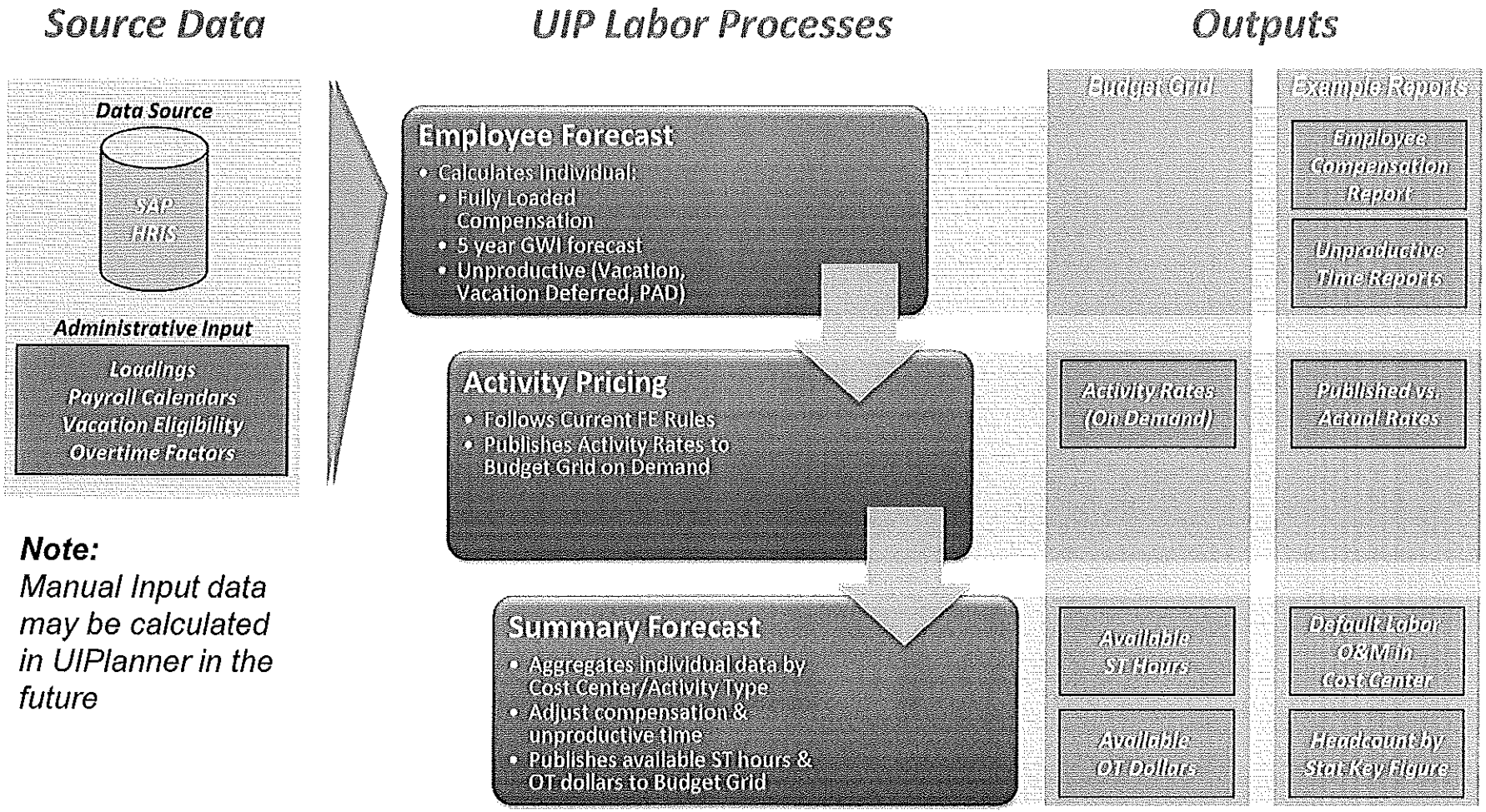


Use the previous slides to perform the following tasks

- Review the new cost center hierarchy for your Business Unit/Department
- Expand and collapse the hierarchy
- Search a cost center
- Perform a cost center lock for an individual cost center or group
  - Remember to unlock all cost centers before exiting the screen

Employee Labor

UIPlanner Labor Schematic



Note:
Manual Input data may be calculated in UIPlanner in the future

The new Labor process ensures that activity rates will be available prior to the budget process while enhancing data security and transparency

Employee Labor Overview - Benefits

Edit Forecasts at Multiple Levels

- Interact with labor data and edit forecasts at the individual employee or cost center level

Activity Prices Prior to Budgeting

- UIPlanner will calculate activity prices prior to the start of the annual budget process. In addition, SAP HR data will be interfaced to UIPlanner monthly

Calendars & Loadings Auto Calculated

- Additional employee information such as vacation eligibility, available payroll hours, etc… will be summarized to help facilitate building of the labor budget

Enhanced Data Security

- Access to the labor screens will be secured based on user role and business unit/department

Automated 5 Year Labor Forecast

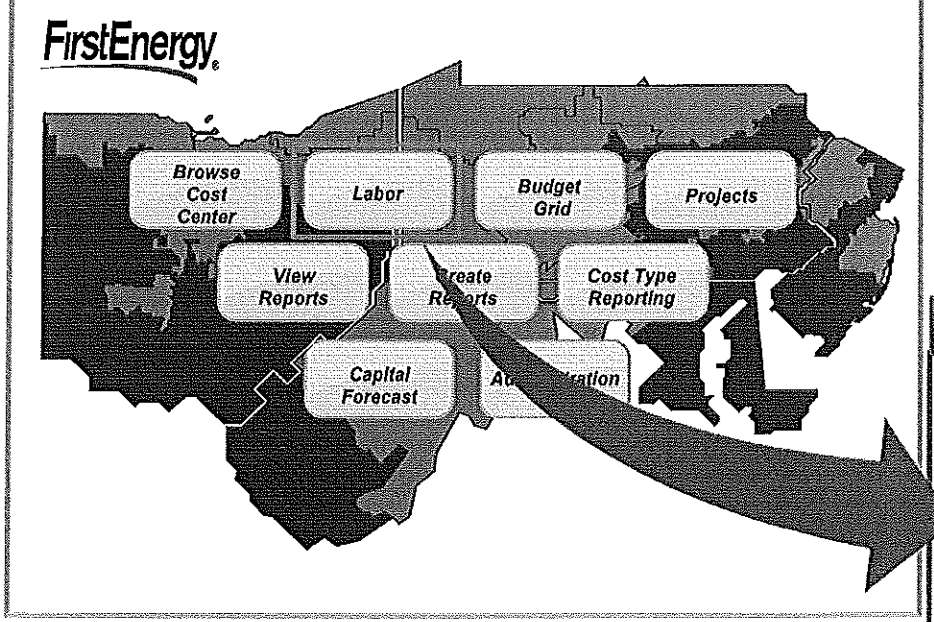
- The correct business rules are applied producing calculated results across the planning horizon for each employee

Labor Attributes Imported from SAP

- *Employee Number*
- *Employee Name*
- *Company*
- *Organization*
- *Personnel Area*
- *Personnel Sub Area*
- *Position*
- *Job*
- *Job Group*
- *Region*
- *Employee Group*
- *Employee Subgroup*
- *Cost Center*
- *Activity Type*
- *Pay Scale Type*
- *Pay Scale Area*
- *Annual Salary*
- *Unit Pay*
- *Vacation Eligibility Date*
- *Latest Hire Date*
- *Vacation Used to Date*
- *PAD Used to Date*
- *Vacation Rolled Over from Previous Year*

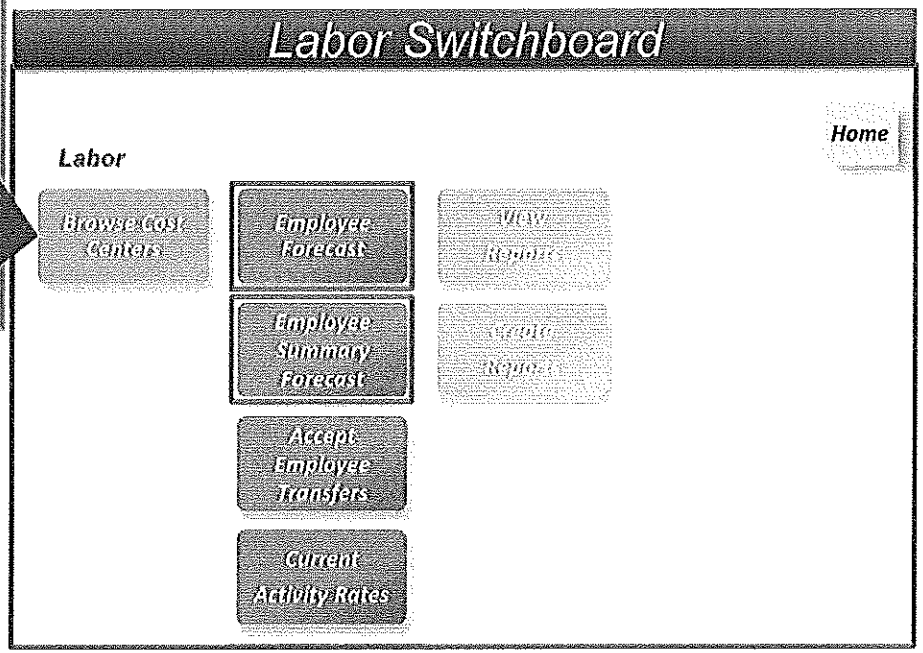
Employee Labor Overview - Navigation

Home Switchboard



1. Click the "Labor" button to open the Labor Switchboard

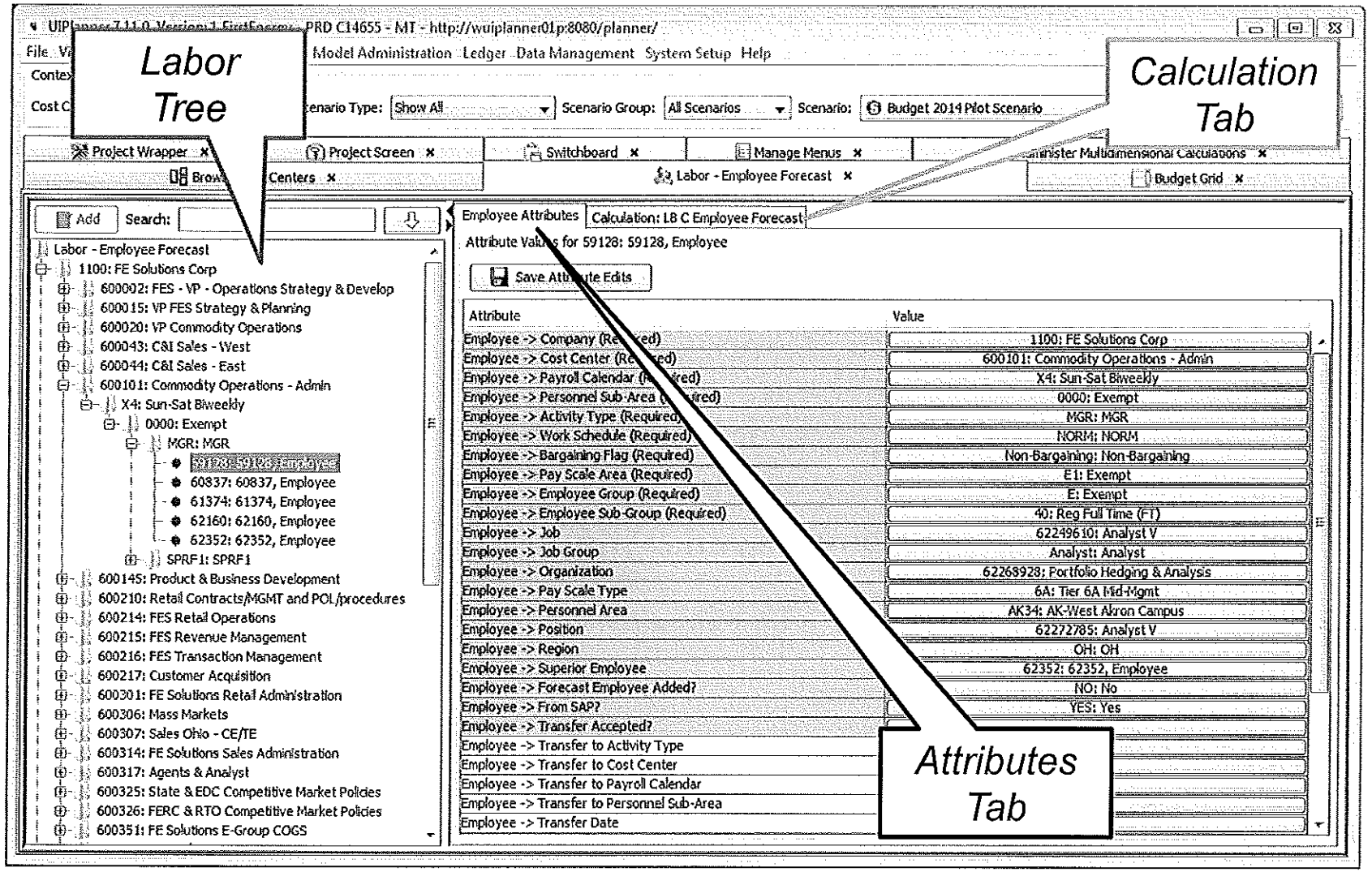
Labor Switchboard



2. Select "Browse Cost Centers" to select the center you wish to view/edit
3. Then click "Employee Forecast"
4. Then click "Summary Forecast"

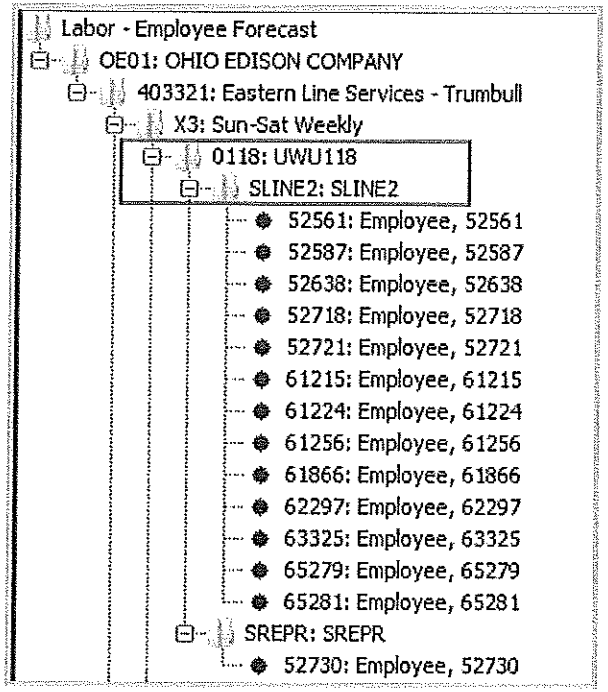
Employee Labor Overview - Wrappers

The Two Labor Wrappers have Three Main Sections

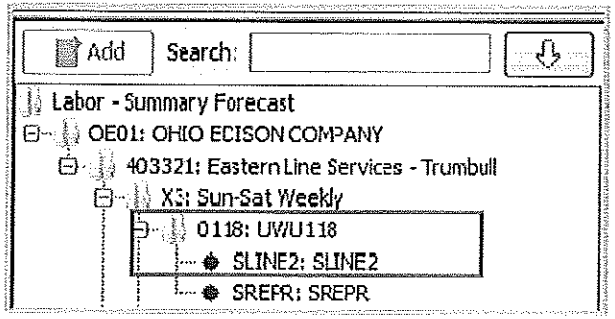


Employee Labor Overview - Trees

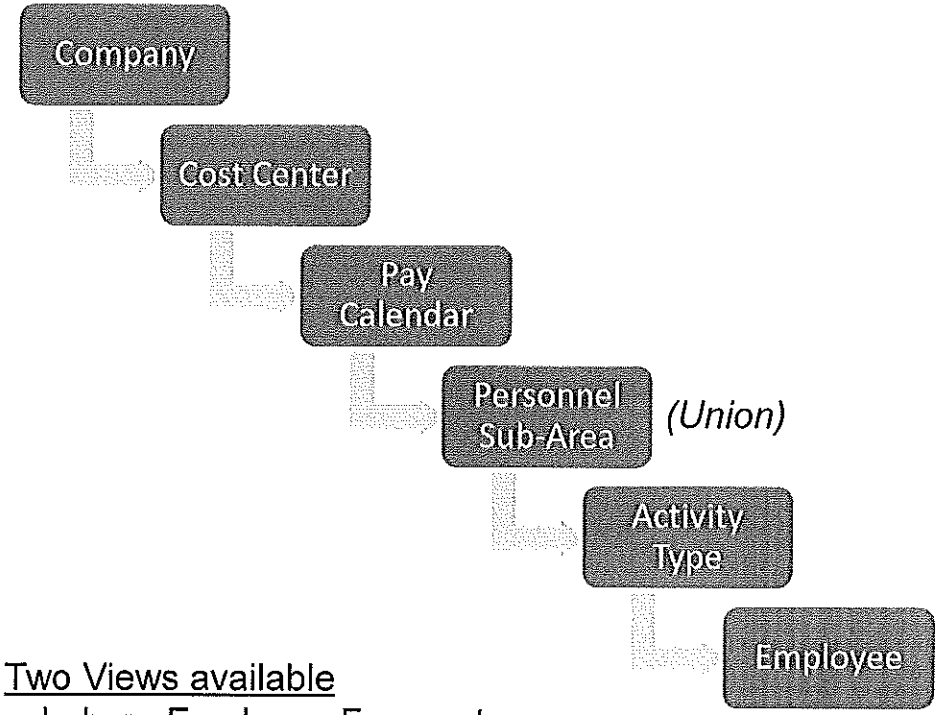
Employee Forecast



Summary Forecast



Labor data will be organized and presented in a tree format by:



Two Views available

- Labor - Employee Forecast
- Labor - Summary forecast

To View Data

- **Employee Forecast:** Open tree to employee level and click on an employee
- **Summary Forecast:** Open tree to activity type level and click on an activity type

Employee Labor Overview – Attributes Tab

The Employee Attributes tab contains a list of each employee's attributes including imported SAP and those that can be set by users

Three Types of Inputs

Attributes: *Opens a dropdown list of attributes*

Dates: *UIPlanner date fields open in a pop-up calendar in MM/YYYY format*

Numbers: *Numbers in UIPlanner can be entered freeform. Note SAP dates in UIPlanner are entered as numbers in YYYYMMDD format*

Employee Attributes | Calculation: L0 C Employee Forecast

Attribute Values for 52561: Employee, 52561

Save Attribute Edits

Attribute	Value
Employee -> Activity Type (Required)	SUINF2: SUINF2
Employee -> Bargaining Flag (Required)	Bargaining: Bargaining
Employee -> Company (Required)	OE01: OHIO EDISON COMPANY
Employee -> Cost Center (Required)	103321: Eastern Line Services - Trumbull
Employee -> Employee Group (Required)	0: Barg/Physical
Employee -> Employee Sub-Group (Required)	40: Reg Full Time (FT)
Employee -> Forecast Employee Added?	NO: No
Employee -> From SAP?	YES: Yes
Employee -> Job	60001666: Line Troubleshooter-U1
Employee -> Job Group	Lineworkers: Lineworker
Employee -> Organization	60000195: RegOH-E: Operations-Warren (OE)
Employee -> Pay Scale Area (Required)	U1: UWUA Local 118/126
Employee -> Pay Scale Type	01: Bargaining
Employee -> Payroll Calendar (Required)	X1: Sun-Sat Weekly
Employee -> Personnel Area	KI01: Kinsman Line Shop
Employee -> Personnel Sub-Area (Required)	0118: UWU118
Employee -> Position	61000182: Line Troubleshooter
Employee -> Region	OH: OH
Employee -> Superior Employee	52573: Employee, 52573
Employee -> Transfer Accepted?	
Employee -> Transfer to Activity Type	
Employee -> Transfer to Cost Center	
Employee -> Transfer to Payroll Calendar	
Employee -> Transfer to Personnel Sub-Area	
Employee -> Work Schedule (Required)	FLEX12HR: Flex 12 hrs
Employee -> Annual Salary (Required)	20800
Employee -> Exit Date	
Employee -> Latest Hire Date (YYYYMMDD) (Required)	19681028
Employee -> PAD Used to Date	48

Select Employee -> Exit Date

Selected Month: | Time Forward | Time Back | Clear

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2013	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2014	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2015	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2016	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2017	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2018	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2019	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2020	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2021	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...

OK | Cancel

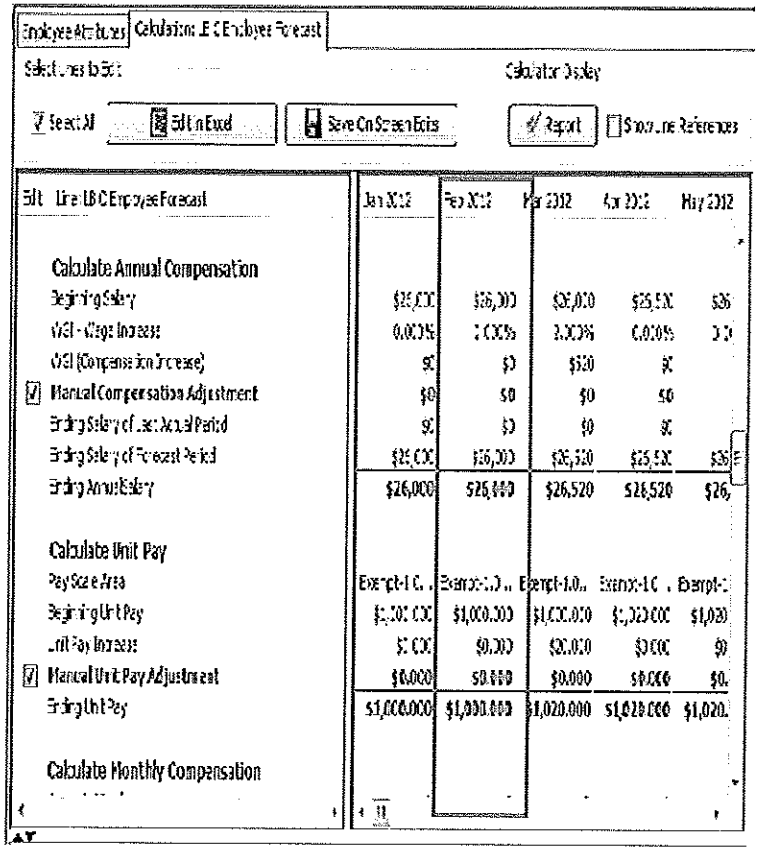
- White attributes **are** editable
- Grey attributes **are not** editable

Employee Labor Overview – Calculations (Overview)

Employee Forecast Calculations

1. Employee Headcount & FTE
2. PAD
3. Vacation
4. Vacation Deferred
5. Unit Pay
   - a. *Bi-Weekly (Exempt)*
   - b. *Hourly (Non-Exempt)*
6. Compensation
   - a. *Monthly Compensation*
   - b. *Annual Compensation*
7. Loadings (Admin Maintained)
   - a. *Incentive Compensation Plan*
   - b. *Payroll Tax*
   - c. *Benefits Loading*
8. Fully Loaded Compensation
9. Productive Time (Activity Pricing) — Hours Available (for Budget Grid)
10. Overtime Factors

- Select the Calculation Tab
- Listed are the key data fields and activity price calculation
- Only rows highlighted in yellow can be edited



Employee Labor Calculations – Headcount & FTE

1 Calculate Headcount & FTE Level

Edit	Line: LB C Employee Forecast	Jan 2014	Feb 2014	Mar 2014	Apr 2014
	Calculate Employee Headcount				
	Begin Employee Count		1	1	1
	Employee Added				
	Employee Exited				-1
	Transfer Employee Out				
	Transfer Employee In				
	End Employee Count		1	1	
	Calculate FTE				
	Begin FTE Count		1.0	1.0	1.0
	Initial FTE Count				
	FTE Added				
	FTE Exited				-1.0
	Transfer FTE Out				
	Transfer FTE In				
☑	**FTE Adjustment**				
	Final FTE Count		1.0	1.0	

- "1" displays for the beginning headcount in the employee labor forecast regardless of employee status
- "1" displays if the employee is considered full time
- "0.5" defaults if the employee status is part-time
- Only part-time employee FTE levels are editable

Employee Labor Calculations – Unproductive Time

2. Calculate PAD
3. Calculate Vacation
4. Calculate Vacation Deferred

Edit	Line: LB C Employee Forecast	Jan 2013	Feb 2013	Mar 2013
	Calculate PAD			
	Begin Available PAD Count		32	32
	Annual PAD Allocation	32		
☑	**Forecasted PAD Use**			
	PAD Used to Date			
	End Available PAD Count	**32**	**32**	**32**
	Vacation Allocation Data			
	Vacation Eligibility Date (YYYYMM)	Oct 1968	Oct 1968	Oct 1968
	Vacation Eligibility Year (YYYY)	1969	1969	1969
	Months of Credit	531	532	533
	Years of Credit for Vacation	44	44	44
	Vacation Allocation Calculation			
	Beginning Vacation Available		160	160
	Vacation Allocation	200		
☑	**Forecasted Vacation Use**	**40**		
	Vacation Used to Date (Last Actual Period)			
	Ending Vacation Available	**160**	**160**	**160**
	Vacation Deferred Calculation			
	Beginning Vacation Deferred		80	80
	Vacation Deferred Allocated	80		
☑	**Forecasted Vacation Deferred Use**			
	Vacation Deferred from Previous Year (Used to...			
	Ending Vacation Deferred Available	**80**	**80**	**80**

- PAD eligibility displays for each employee
- Forecast PAD for employee by entering the number of hours forecasted each month

- Vacation hours available
- Vacation calculation based on employee service
- Forecast Vacation for employee by entering the number of hours forecasted each month
- Hours reduced for following month

- Vacation Deferred available
- Forecast Vacation Deferred for employee by entering the number of hours forecasted each month

Employee Labor Calculations - Compensation

5 Unit Pay (w/ GWI Increases)

6 Calculate Compensation

Edit	Line: LB C Employee Forecast	Oct 2014	Nov 2014	Dec 2014
	Calculate Unit Pay			
	Pay Scale Area	Exempt-1.0...	Exempt-1.0...	Exempt-1.0...
	Beginning Unit Pay	$2,118.469	$2,118.469	$2,118.469
	GWI - Wage Increase (%)			
	Unit Pay Increase			
☑	**Manual Unit Pay Adjustment**			
	Ending Unit Pay	**$2,118.469**	**$2,118.469**	**$2,118.469**
6a	**Calculate Monthly Compensation**			
	Weeks in Month	4	4	4
	Hours Per Week	40	40	40
	Total Hours in Month	160	160	160
	Monthly Compensation (Exempt)	$4,237	$4,237	$4,237
	Monthly Compensation (Hourly)			
	Annual Direct Salary			$54,872
	Total ST Hours in Year			2,080

Edit	Line: LB C Employee Forecast	Oct 2014	Nov 2014	Dec 2014
6b	**Calculate Annual Compensation**			
	Annual Employee Hours	2,080	2,080	2,080
	Current Month ST Hours	160	160	160
	Beginning Annual Salary	$55,080	$55,080	$55,080
	GWI - Wage Increase (%)			
	GWI - Compensation Increase			
	Ending Annual Salary	$55,080	$55,080	$55,080
	Bonus Compensation Allocation			
☑	**Bonus Compensation**			

- Display pay scale are and unit pay
- Enter pay adjustments if applicable (promotion, non ICP bonus, etc...)
- Based on employee, number of hours available displays
- Total monthly compensation calculated
- Annual compensation calculated
- Add additional bonus pay

Employee Labor Calculations - Loadings

7 Compensation Loadings

Edit	Line: LB C Employee Forecast	Oct 2014	Nov 2014	Dec 2014
	Compensation Loadings			
7a	**Incentive Compensation Loading**			
	Monthly Compensation	$4,237	$4,237	$4,237
	* Incentive Compensation Loading (%)	10.00%	10.00%	10.00%
	Incentive Compensation Allocated	$424	$424	$424
7b	**Payroll Tax Loading**			
	Monthly Compensation	$4,237	$4,237	$4,237
	* Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	Payroll Tax for Base Compensation	$319	$319	$319
	Incentive Compensation Allocated	$424	$424	$424
	* Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	Payroll Tax for ICP	$32	$32	$32
	Payroll Tax for Base Compensation	$319	$319	$319
	Payroll Tax for ICP	$32	$32	$32
	Payroll Tax Allocated	$351	$351	$351
7c	**Benefits Loading**			
	Monthly Compensation	$4,237	$4,237	$4,237
	* Benefits Loading (%)	22.14%	22.14%	22.14%
	Benefits Allocated	$938	$938	$938

- Compensation loadings calculated
- Incentive Compensation, Payroll Tax, and Benefits percentages stored in multidimensional dataset

Employee Labor Calculations – Total Loaded Compensation

8 Fully Loaded Compensation

Edit	Line: LB C Employee Forecast	Oct 2014	Nov 2014	Dec 2014
	Total Compensation Loadings			
	Incentive Compensation Loading (%)	10.00%	10.00%	10.00%
	+ Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	+ Payroll Tax Loading (%) * ICP (%)	0.75%	0.75%	0.75%
	+ Benefits Loading (%)	22.14%	22.14%	22.14%
	Total Loading Percent	40.43%	40.43%	40.43%
8a	**Loaded Monthly Compensation**			
	Incentive Compensation Allocated	$326	$326	$326
	+ Payroll Tax Allocated	$271	$271	$271
	+ Benefits Allocated	$723	$723	$723
	Total Loading Dollars	$1,320	$1,320	$1,320
	+ Monthly Compensation	$3,264	$3,264	$3,264
	Loaded Monthly Compensation	**$4,584**	**$4,584**	**$4,584**
8b	Loaded Annual Salary for Activity Pricing			**$59,364**
	Loaded Bonus Compensation Allocation			
	Bonus Compensation			
	* Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	Total Loaded Bonus Compensation			

- Compensation loadings listed totaling labor additives
- Compensation dollars totaling for labor additives
- Loadings applied to Bonus Compensation dollars

Employee Labor Calculations – Available Hours

9 Calculate Available Hours

Edit	Line: LB C Employee Forecast	Oct 2014	Nov 2014	Dec 2014
	Calculate Productive Time for Activity P...			
	Straight-time Hours in Months	160	160	160
	Meeting Hours	3.33	3.33	3.33
	Unproductive Time (Additional)			
	Total Hours in Year			2,080
	Meeting Hours in Year			40
	Unproductive Time (Additional) in Year			
	Vacation Allocation			85
	PAD Allocation + Holiday			96
	Productive Time in Year			**1,859**
	Hours Available for Budgeting			
	Total Hours in Month	160	160	160
	Vacation Budgeted/Used			
	Vacation Deferred Budgeted/Used			
	PAD Hours Budgeted/Used			
	Holiday Hours			16
☑	**Miscellaneous Unproductive Time in Budget**			
	Time Available for Budgeting	160	160	144

- Productive time calculated for activity pricing
- Hours available for budgeting
- Include additional unproductive time

Under development - Descriptions will display

Employee Labor Calculations – Overtime Inputs

10 Overtime Loadings

Edit	Line: LB C Employee Forecast	Jan 2013	Feb 2013	Mar 2013
	Monthly Base Salary	$3,200.00	$3,200.00	$4,000.00
	Escalation Factor	1.67780	1.67780	1.67780
	Monthly Overtime Base Salary	$5,368.96	$5,368.96	$6,711.20
	Incentive Compensation Loading	5.00%	5.00%	5.00%
	Incentive Compensation for Overtime	$268.45	$268.45	$335.56
	Monthly Overtime Base Salary	$5,368.96	$5,368.96	$6,711.20
	+ Incentive Compenstation for Overtime	$268.45	$268.45	$335.56
	Taxable Overtime Compensation	$5,637.41	$5,637.41	$7,046.76
	* Tax Loading	7.54%	7.54%	7.54%
	Taxes On Base Salary for Overtime	$425.06	$425.06	$531.33
	Monthly Loaded Salary for Overtime	$6,062.47	$6,062.47	$7,578.09
	Monthly Hours for Overtime	160	160	200

- Escalation factors are used to inflate base salaries to approximate hourly overtime rates

Employee Labor - How to Update Data

Two options to update Employee Labor

Edit on Screen



- *Inputs can be made directly in the screen.*
- *Select save on screen edits*

Edit In Excel



	B	C	D	E
1	Line Item to Edit	Jan 2013	Feb 2013	Mar 2013
2				
3	VR:[Forecasted PAD Use]			
4	WY:[Forecasted Vacation Use]			
5	YI:[Forecasted Vacation Deferred Use]			
6	ZC:[Manual Unit Pay Adjustment]			
7	ABM:[Bonus Compensation]			
8	AEL:[Miscellaneous Unproductive Time in Budget]			

- You can edit the rows highlighted in yellow or Select the **Edit in Excel** to update
  - When editing in Excel simply close out to save
  - Column headings will need to remain in tact in order to properly save

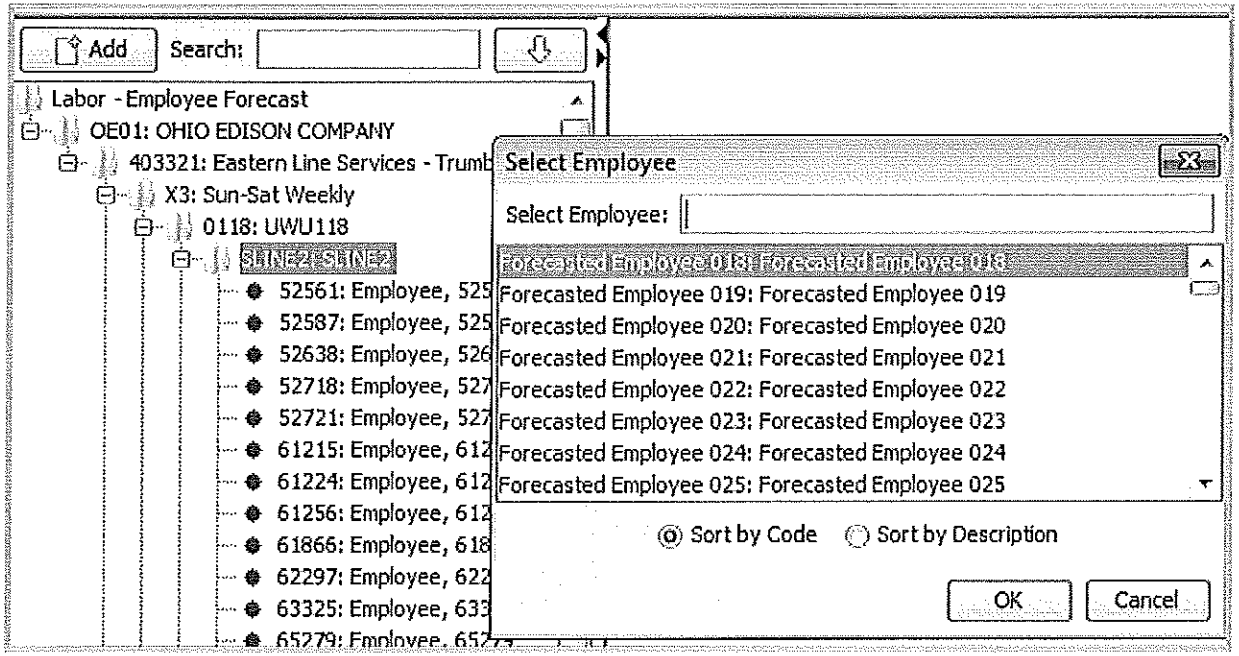
Employee Labor – Forecasting Headcount Changes

Employee Labor – Add a Forecast Employee

Forecast Employees are employee entities which can be added to the labor forecast to forecast new employees in a department. Forecast Employees should be used when either: ***1.) the position has been filled and the employee has not started yet, or 2.) the Cost Center/Activity Type does not exist within FE.***

Process: To add Forecast Employee

- Highlight the activity type
- Click the **Add** button
- Select a forecast employee to add
- Fill in required attributes



Required Attributes

- Company
- Cost Center
- Payroll Calendar
- Personnel Sub-Area
- Activity Type
- Work Schedule
- Pay Scale Area
- Employee Group
- Employee Sub-Group

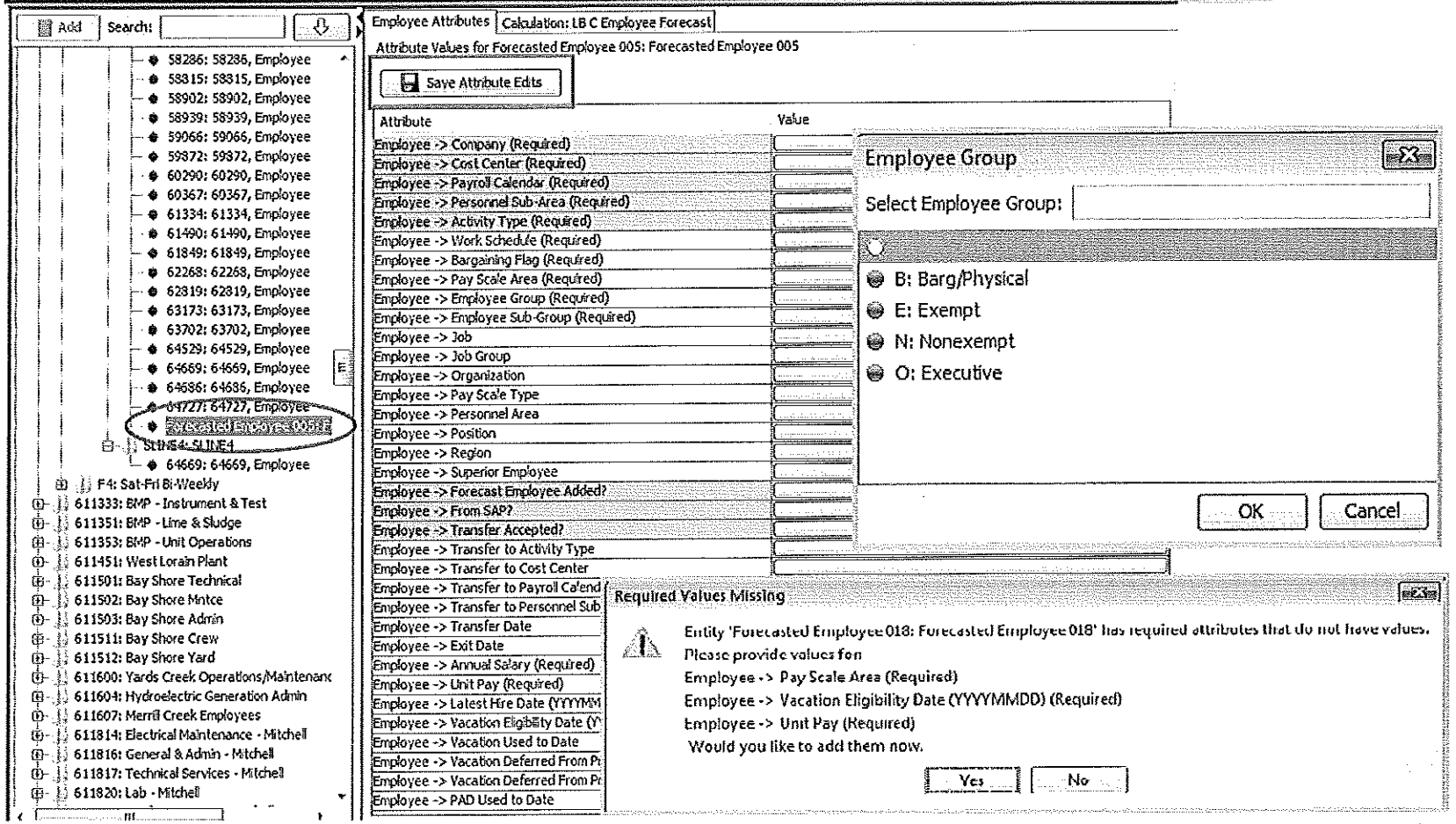
Required Inputs

- Annual Salary
- Unit Pay
- Latest Hire Date (YYYYMMDD)
- Vacation Eligibility Date (YYYYMMDD)

Employee Labor – Add a Forecast Employee

- **Enter all required fields**
  - Searchable drop boxes appear for attributes
  - Monthly Calendars appear for UIPlanner Date fields
  - Type directly into number fields (including SAP date formats – YYYYMMDD)
- Select **Save Attribute Edits** when complete

  Note: An error message will occur if required fields are left blank



Employee Labor – Add a Forecast Employee

- Select the **Calculation: LB C Employee Forecast** tab
- View auto populated data

Employee Attributes | Calculation: LB C Employee Forecast

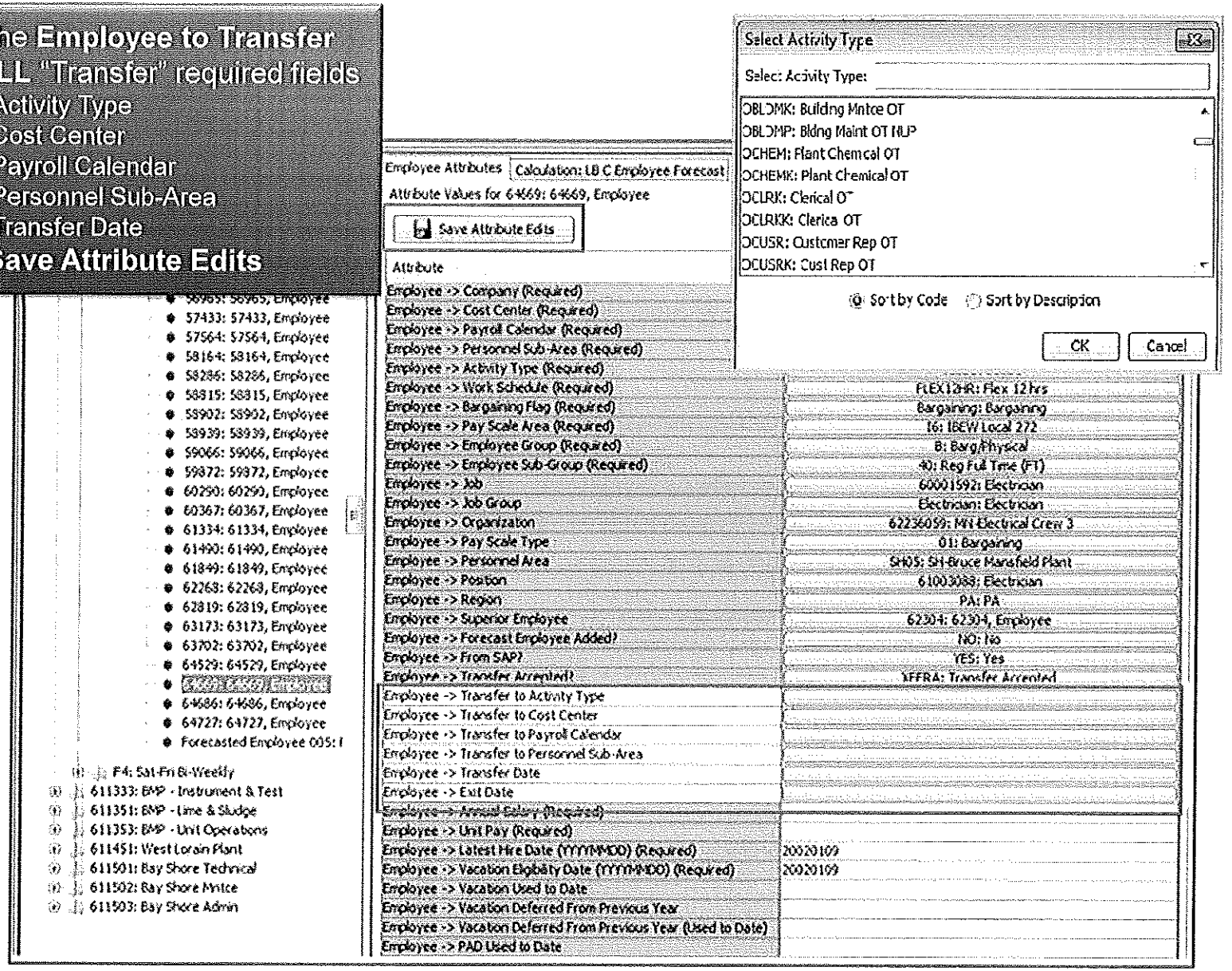
Attribute Values for Forecasted Employee 018: Forecasted Employee 018

Edit	Line: LB C Employee Forecast	Feb 2014	Mar 2014	Apr 2014
	Calculate Employee Headcount			
	Begin Employee Count		1	1
	Employee Added	1		
	Employee Exited			
	Transfer Employee Out			
	Transfer Employee In			
	End Employee Count	1	1	1
	Calculate FTE			
	Begin FTE Count		1.0	1.0
	Initial FTE Count			
	FTE Added	1.0		
	FTE Exited			
	Transfer FTE Out			
	Transfer FTE In			
☑	**FTE Adjustment**			
	Final FTE Count	1.0	1.0	1.0

Line: LB C Employee Forecast	Feb 2014	Mar 2014	Apr 2014	May 2014
Calculate Unit Pay				
Pay Scale Area	IBEW Local ...	IBEW Local ...	IBEW Local ...	IBEW Local ...
Beginning Unit Pay	$25.750	$25.750	$25.750	$25.750
GWI - Wage Increase (%)				
Unit Pay Increase				
Manual Unit Pay Adjustment				
Ending Unit Pay	$25.750	$25.750	$25.750	$25.750
Calculate Monthly Compensation				
Weeks in Month	4	4	4	5
Hours Per Week	40	40	40	40
Total Hours in Month	160	160	160	200
Monthly Compensation (Exempt)				
Monthly Compensation (Hourly)	$4,120	$4,120	$4,120	$5,150
Annual Direct Salary				
Total ST Hours in Year				
Calculate Annual Compensation				
Annual Employee Hours	2,080	2,080	2,080	2,080
Current Month ST Hours	160	160	160	200
Beginning Annual Salary		$53,560	$53,560	$53,560
GWI - Wage Increase (%)				
GWI - Compensation Increase				
Ending Annual Salary	$53,560	$53,560	$53,560	$53,560

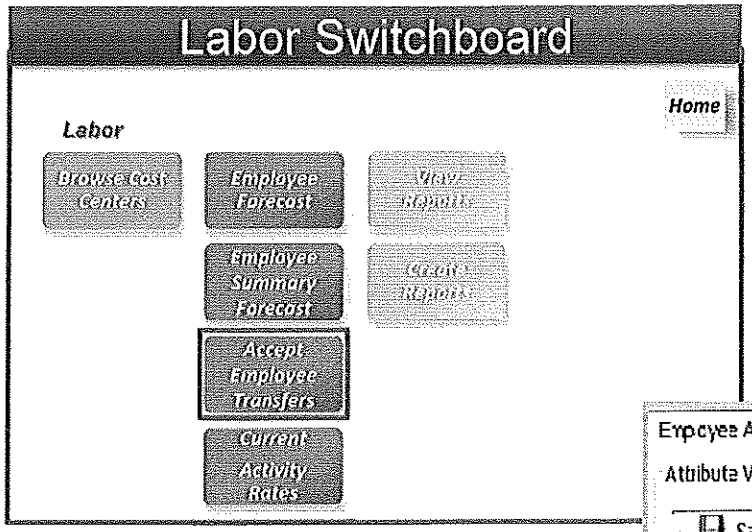
Employee Labor – Transfer Individual Employee

- Select the **Employee to Transfer**
- Enter **ALL** "Transfer" required fields
  - Activity Type
  - Cost Center
  - Payroll Calendar
  - Personnel Sub-Area
  - Transfer Date
- Select **Save Attribute Edits**

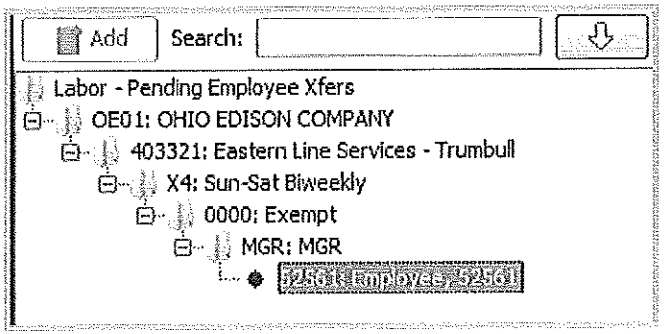


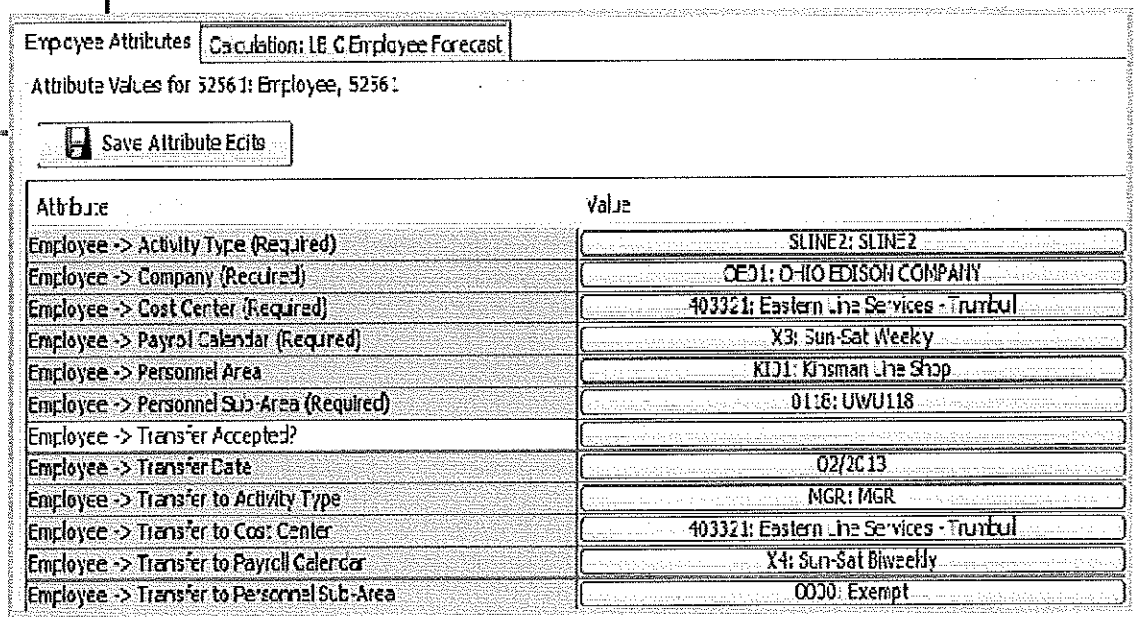
Employee Labor – Transfer Individual Employee

Step 1
- Open the switchboard tab
- Click **Accept Employee Transfers**



Step 2
- Highlight transfer employee
- Select **Yes** to accept transfer
- Select **Save Attributes**





Employee Labor – Verify Transfer

- Select **Employee Forecast** Wrapper
- Employee displays in both old and new cost center
- Record adjusts to reflect transfer date, new pay area and activity type
- Preserves the employee's PAD, Vacation, etc…

Original Record



Edit	Line: LB C Employee Forecast	Apr 2014	May 2014	Jun 2014
	Calculate Employee Headcount			
	Begin Employee Count	1	1	1
	Employee Added			
	Employee Exited			
	Transfer Employee Out			-1
	Transfer Employee In			
	End Employee Count	1	1	
	Calculate FTE			
	Begin FTE Count	1.0	1.0	1.0
	Initial FTE Count			
	FTE Added			
	FTE Exited			
	Transfer FTE Out			-1.0
	Transfer FTE In			
☑	**FTE Adjustment**			
	Final FTE Count	1.0	1.0	

Transfer Record

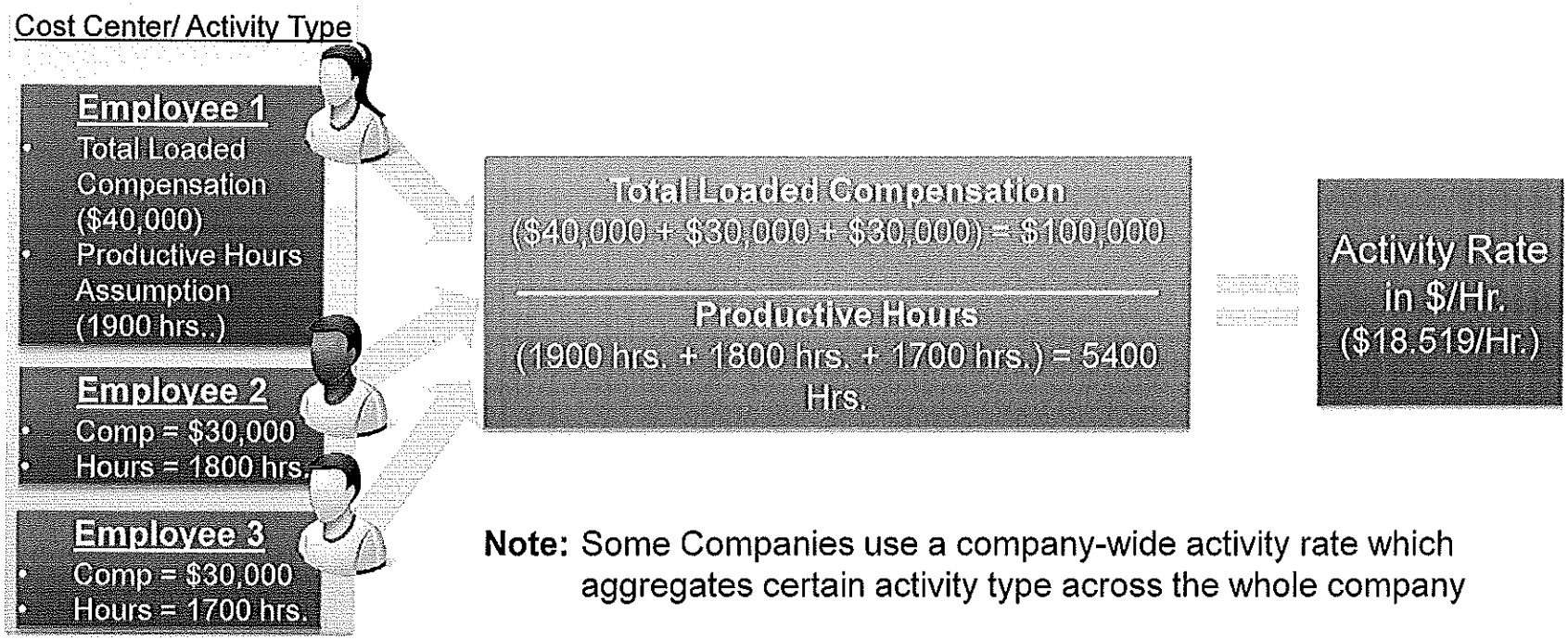


Edit	Line: LB C Employee Forecast	Jun 2014	Jul 2014
	Calculate Employee Headcount		
	Begin Employee Count		1
	Employee Added		
	Employee Exited		
	Transfer Employee Out		
	Transfer Employee In	1	
	End Employee Count	1	1
	Calculate FTE		
	Begin FTE Count		1.0
	Initial FTE Count		
	FTE Added		
	FTE Exited		
	Transfer FTE Out		
	Transfer FTE In	1.0	
☑	**FTE Adjustment**		
	Final FTE Count	1.0	1.0

Employee Labor – Activity Pricing in UIPlanner

Employee Labor – Activity Pricing

Activity Rates are used to allocate labor to projects, orders, and cost centers other than the employees' home center.



Note: Some Companies use a company-wide activity rate which aggregates certain activity type across the whole company

Activity Pricing FAQ

Does Forecasting Vacation Use Affect Activity Rates?

No. The unproductive time in the Activity Pricing Calculation uses assumptions for unproductive time including assumed meeting hours and utilization of all vacation & PAD earned in a year.

Does Adding Compensation Affect Activity Rates?

It depends. If a future raise or promotion for an employee is known, it could be added to the employee prior to the activity pricing process. However, forecast compensation changes made during the annual budget process or reforecasting will not affect rates

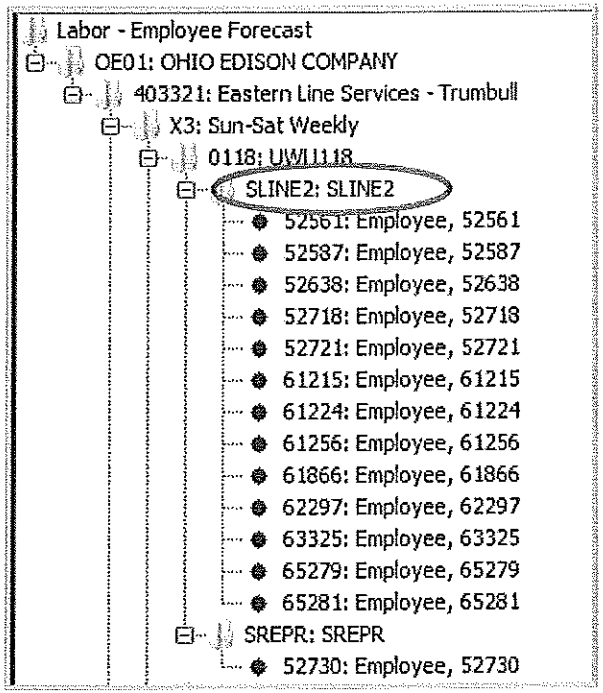
Does Adding an Employee Affect Activity Rates?

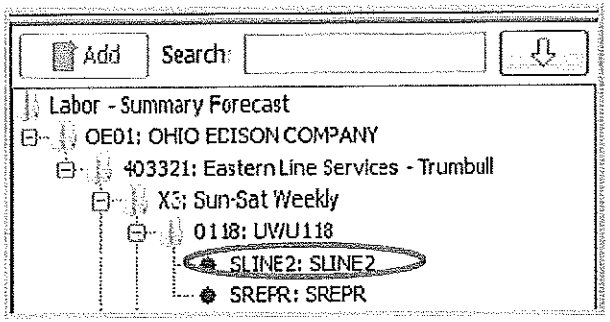
No. Activity Rates are set and published prior to users being able to edit and add employees

Employee Labor – Summary Forecast

Employee Labor – Summary Forecast

Employee Summary wrapper summarizes individual employee information to the cost center activity type level for each cost center

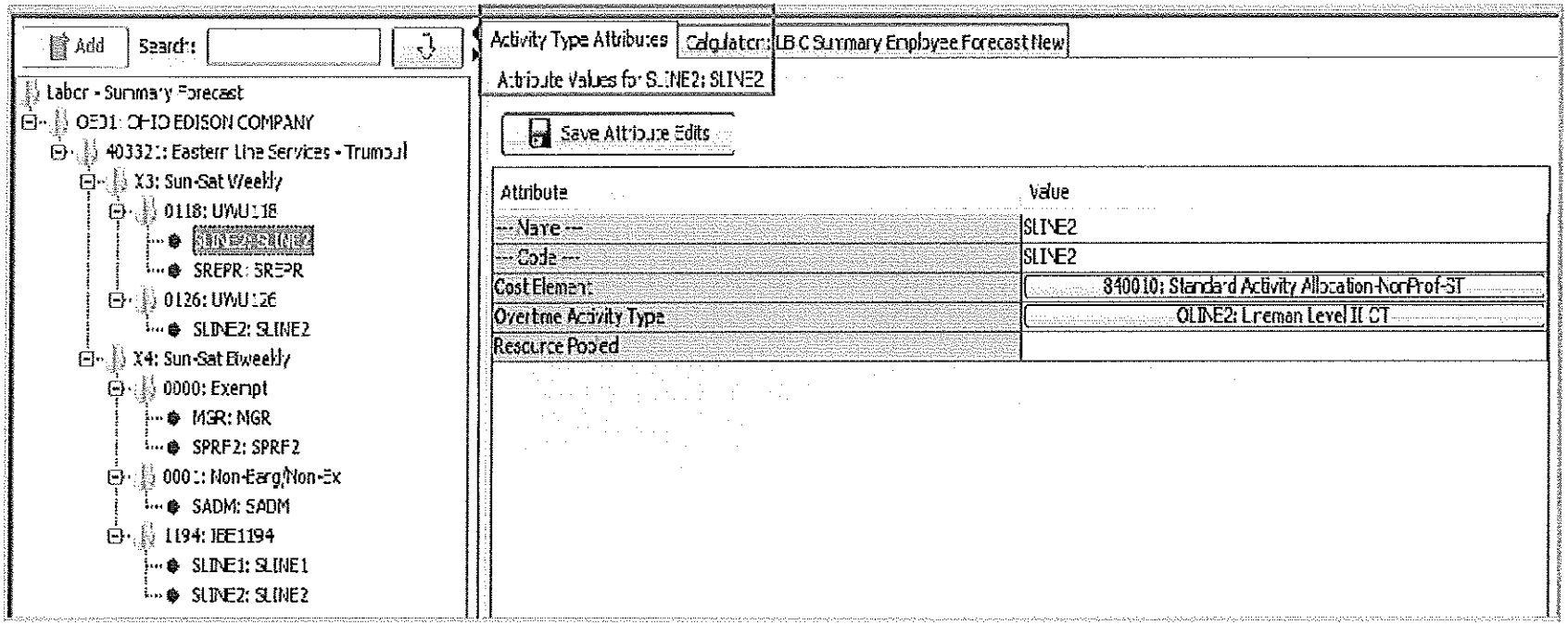




Information related to SLINE2 activity type is summarized in the Employee Summary wrapper

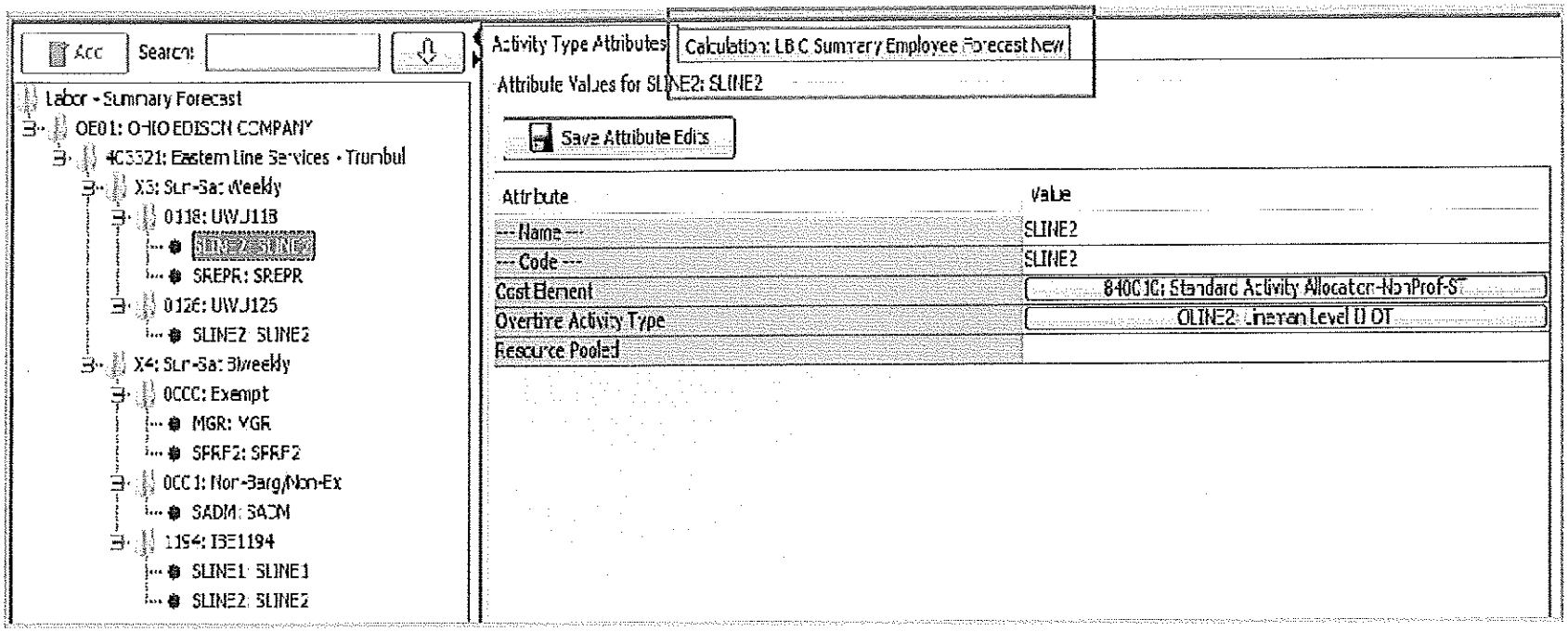
Employee Labor – Summary Forecast

- Select **Activity Type Attributes**
- Information auto populated



Employee Summary

Select **Summary Employee Forecast**



To add a new activity type to a cost center either:

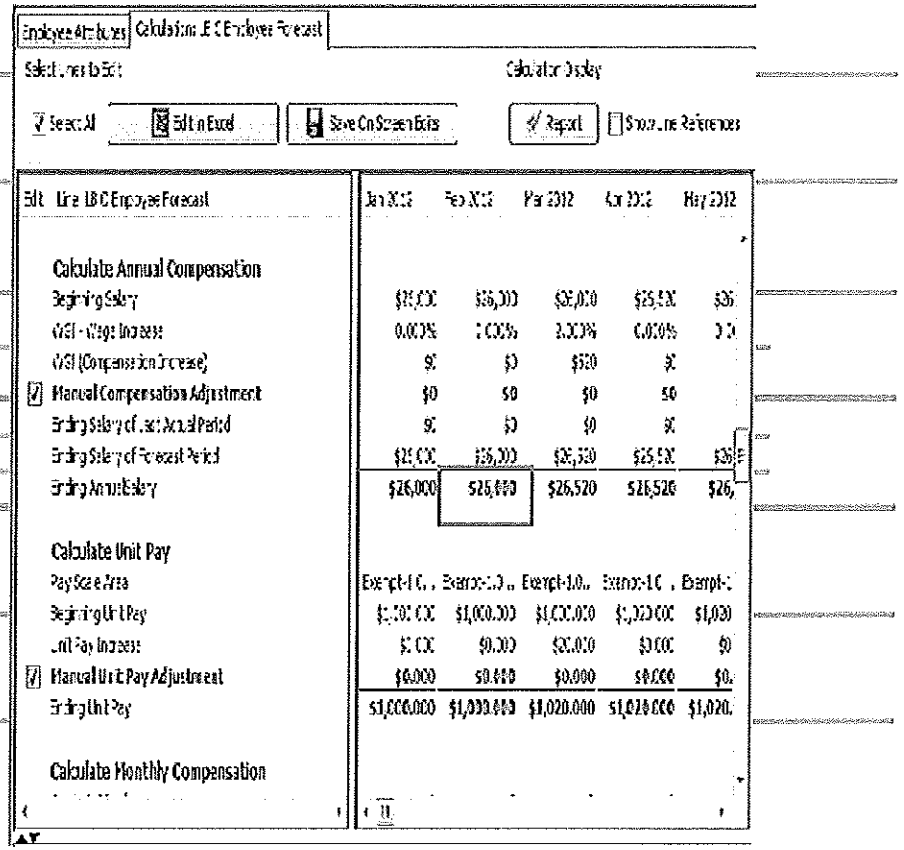
- Add a forecast employee with the desired Cost Center/Activity Type combination
- **Transfer an employee into the Cost Center/Activity Type combination (if the new combo occurs as a result of a transfer)**

Employee Summary – Calculations (Overview)

Summary Forecast Calculations

1. Headcount & FTE
2. PAD
3. Vacation
4. Vacation Deferred
5. Compensation
   - a. Monthly Compensation
   - b. Annual Compensation
6. Loadings (Admin Maintained)
   - a. Incentive Compensation Plan
   - b. Payroll Tax
   - c. Benefits Loading
7. Bonuses
8. Straight Time Hours (for Budget Grid)
9. Overtime Dollars (for Budget Grid)

- Select the Calculation Tab
- Listed are the key data fields and activity price calculation
- Only rows highlighted in yellow can be edited



Employee Summary

1 Calculate Headcount & FTE Level

- Summary wrapper summarizes data from employee wrapper by cost center, pay area and activity type
- Information auto populated
- Similar to the employee forecast wrapper, users can edit rows highlighted in yellow

Edit	Line: LB C Summary Employee Forecast...	Apr 2014	May 2014	Jun 2014
	Calculate Employee Count			
	Begin Headcount	3	3	3
	Employee Forecast Headcount Change			
☑	**Regular FT Headcount Change**			
☑	**Regular PT Headcount Change**			
☑	**Student/Intern Headcount Change**			
☑	**Temporary Employee Headcount C...**			
	End Headcount	3	3	3
	Calculate FTE Count			
	Begin FTE Count	3.00	3.00	3.00
	+ Employee Forecast FTE Change			
☑	**Regular FT FTE Change**			
☑	**Regular PT FTE Change**			
☑	**Student/Intern FTE Change**			
☑	**Temporary Employee FTE Change**			
	End FTE Count	3.00	3.00	3.00

Employee Summary – Available Hours for Grid

2. Calculate PAD
3. Calculate Vacation
4. Calculate Vacation Deferred

Edit	Line: LB C Summary Employee Forecast...	Apr 2014	May 2014	Jun 2014
	PAD Forecast			
	Beginning PAD Available	96	96	96
	+ PAD Allocation			
	+ Change in PAD Allocation from EF Tran...			
☑	**+ Additional PAD Allocation**			
	- Actual PAD Used			
	- Employee Forecast PAD Use			
☑	**- Forecasted PAD Use**			
	End Available PAD Hours	96	96	96
	Vacation Forecast (VPAD)			
	Beginning Vacation Available	360	360	360
	+ Vacation Allocation			
	+ Change in Vacation Allocation from EF ...			
☑	**+ Additional Vacation Allocation**			
	- Actual Vacation Used			
	- Employee Forecasted Vacation Use			
☑	**- Forcasted Vacation Use**			
	End Available Vacation Hours	360	360	360
	Vacation Deferred Forecast			
	Begining Vacation Deferred Available	64	64	64
	+ Vacation Deferred Allocation from Empl...			
	+ Change in Vacation Deferred Allocatio...			
☑	**+ Additional Vacation Deferred Allo...**			
	- Actual Vacation Deferred Used to Date			
	- Employee Forecasted Vacation Deferre...			
☑	**- Forecasted Vacation Deferred Use**			
	End Available Vacation Deferred Hours	64	64	64

Employee Summary – Compensation

5 Compensation

Edit	Line: LB C Summary Employee Forecast...	Apr 2014	May 2014	Jun 2014
	Calculate Monthly Compensation			
	Weeks in Month	4	4	4
	Pay Periods in Month	2	2	2
	GWI - Wage Increase			
	Hours/Week per FTE	40	40	40
	Initial Direct Compensation	$32,892	$32,892	$32,892
	Employee Direct Compensation Increase			
	Compensation Change due to FTE Change			
	Adjusted Previous Manual Direct Compen...			
☑	**Manual Direct Compensation Incre...**			
	Direct Compensation Available for Budge...	$32,892	$32,892	$32,892
	Annual Direct Compensation			

Employee Summary – Compensation

6 Loadings

Edit	Line: LB C Summary Employee Forecast...	Apr 2014	May 2014	Jun 2014
	Compensation Loadings			
6a	**Incentive Compensation Loading**			
	Monthly Compensation	32,892	32,892	32,892
	* Incentive Compensation Loading (%)	10.00%	10.00%	10.00%
	Incentive Compensation Allocated	$3,289	$3,289	$3,289
6b	**Compensation Tax Loading**			
	Direct Compensation	$32,892	$32,892	$32,892
	* Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	Payroll Tax for Direct Compensation	$2,480	$2,480	$2,480
	Incentive Compensation	$3,289	$3,289	$3,289
	* Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	Payroll Tax for ICP	$248	$248	$248
	Payroll Tax for Direct Compensation	$2,480	$2,480	$2,480
	Payroll Tax for ICP	$248	$248	$248
	Payroll Tax Allocated	$2,728	$2,728	$2,728
6c	**Benefits Loading**			
	Direct Compensation	$32,892	$32,892	$32,892
	* Benefits Loading (%)	22.14%	22.14%	22.14%
	Benefits Allocated	$7,282	$7,282	$7,282

Employee Summary – Compensation

6 Loading *Percentages*

Edit	Line: LB C Summary Employee Forecast...	Oct 2014	Nov 2014	Dec 2014
6a	**Benefits Loading**			
	Direct Compensation	$32,892	$32,892	$32,892
	* Benefits Loading (%)	22.14%	22.14%	22.14%
	Benefits Allocated	$7,282	$7,282	$7,282
6b	**Total Compensation Loadings**			
	Incentive compensation Loading (%)	10.00%	10.00%	10.00%
	+ Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	+ Payroll Tax Loading (%) * ICP (%)	0.75%	0.75%	0.75%
	+ Benefits Loading (%)	22.14%	22.14%	22.14%
	Total Loading Percent	40.43%	40.43%	40.43%
6c	**Loaded Monthly Compensation**			
	Incentive compensation Allocated	$3,289	$3,289	$3,289
	+ Payroll Tax Allocated	$2,728	$2,728	$2,728
	+ Benefits Allocated	$7,282	$7,282	$7,282
	Total Loading Dollars	$13,300	$13,300	$13,300
	+ Monthly Direct Compensation	$32,892	$32,892	$32,892
5a	Loaded Monthly Compensation	$46,191	$46,191	$46,191
5b	Loaded Annual Compensation			**$598,224**

***Note:** Annual Totals only appear in December*

Employee Summary – Compensation

7 Bonuses

Bonuses are entered in the Bonus line, and Payroll Tax for Bonus Compensation is calculated to yield Total Bonus Compensation

Edit	Line: LB C Summary Employee Forecast...	Oct 2014	Nov 2014	Dec 2014
	Bonus Compensation			
	Employee Forecast Bonus Compensation			
☑	**Bonus Compensation**	$1,000		
	Total Bonus Compensation	$1,000		
	* Payroll Tax Loading	7.54%	7.54%	7.54%
	Bonus Compensation Payroll Taxes	$75		
	+ Total Bonus Compensation	$1,000		
	Total Loaded Bonus Compensation	$1,075		

Employee Summary – Compensation

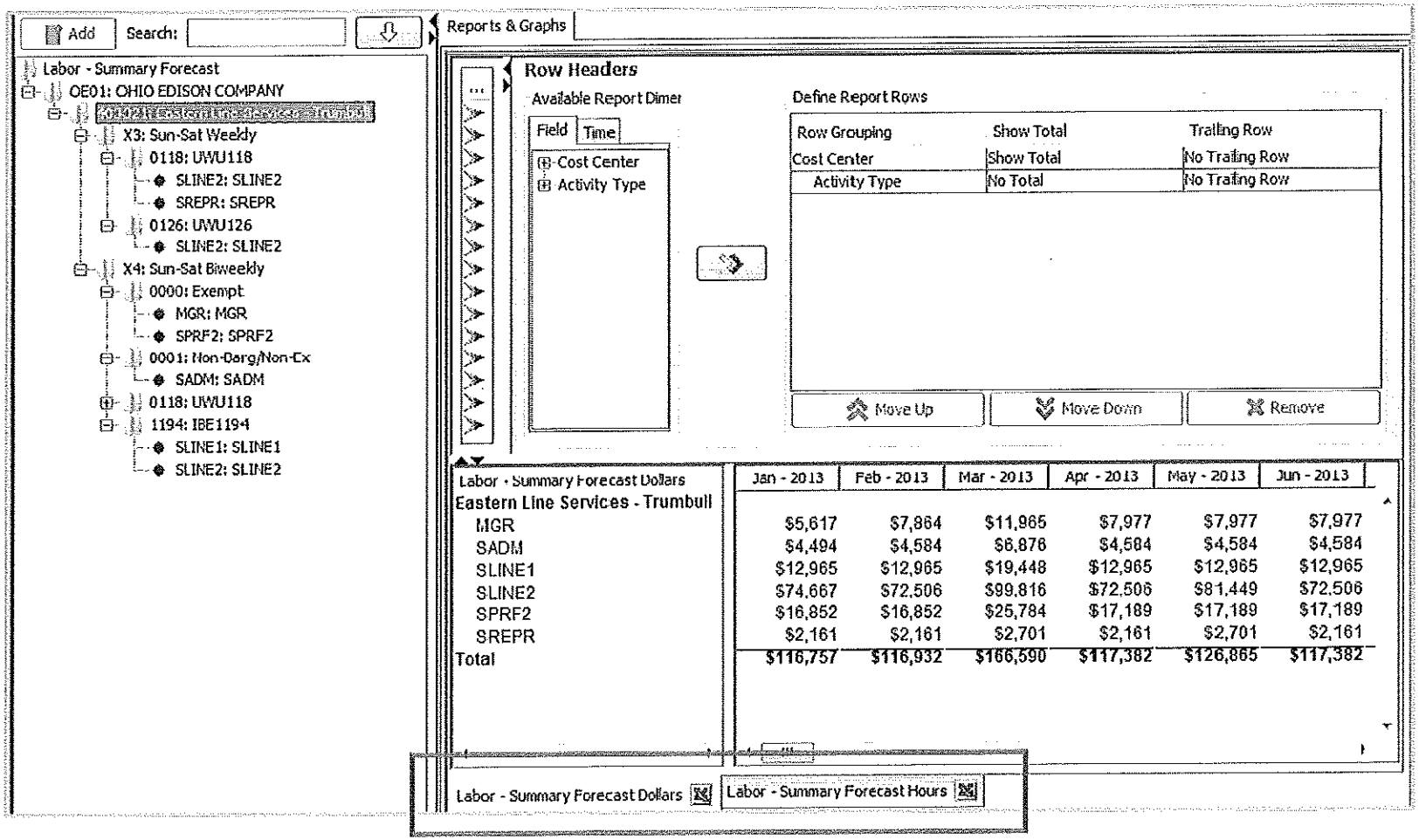
8 Straight Time Hours for Budget Grid

9 Overtime Dollars for Budget Grid

Edit	Line: LB C Summary Employee Forecast...	Jan 2014	Feb 2014	Mar 2014	Apr 2014
	Budgeting				
	Payroll Calendar				
	Weeks in Month	6	4	4	4
	Pay Periods in Month	3	2	2	2
	FTE	5	5	5	5
	Hours Available for Budgeting				
	Total ST Hours in Month	1,200	800	800	800
	+ ST Hours due to Change in FTE				
	- PAD Hours Used				
	- Vacation Used				
	- Vacation Deferred Used				
	- Holiday Hours	120			
	- Holiday Hours due to Change in FTE				
	- Miscellaneous Unproductive Hours in Bu...				
☑	**- Miscellaneous Unproductive Hour...**			**120**	
	Hours Available for Budgeting	1,080	800	680	800
	Overtime Budgeting				
	Activity Price				
	Overtime Activity Type	Prof Level II...	Prof Level II...	Prof Level II...	Prof Level II...
	Overtime Activity Price	$67.113	$67.113	$67.113	$67.113
	Budget Overtime				
☑	**Overtime Hours**	**120.0**			
	* Overtime Activity Rate	$67.113	$67.113	$67.113	$67.113
	Overtime Dollars	$8,054			

Employee Summary – Wrapper Reports

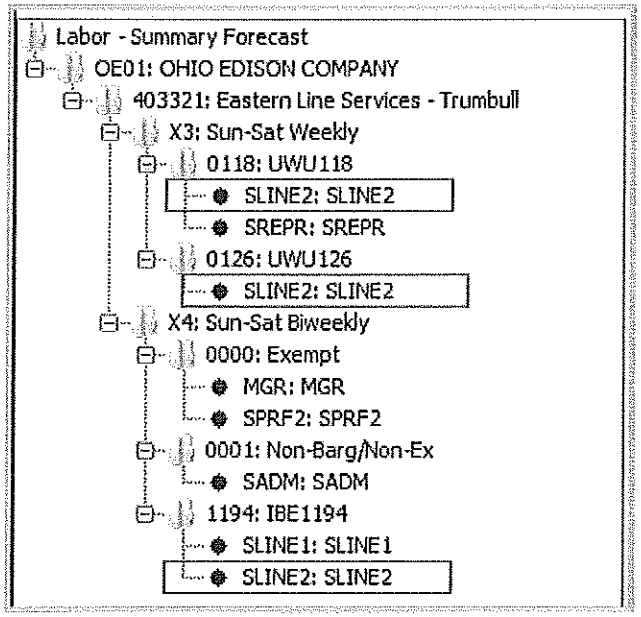
- View total hours and dollars by activity type at the cost center level
- Report will be view only



Employee Summary to Budget Grid

- The grid is used to allocate hours and dollars
- If labor is not activity allocated, then labor dollars will not show on the grid. Information is available via report

Cost Source	Cost Owner	Cost Collector Ty	Project	WBS	Internal Order	Activity Type	Cost Element	Comment	Amount Type	2013
Filter Off	Filter Off	Filter Off	Filter Off	...	Filter Off	Filter On	Filter Off			2013 - Jan
403321: Eastern L	401221: Centra	WBS	WBS	OE-900083: N-Line	OE-9000	N/A: N/A	SLINE: Lineman-a	840010: Stand		
									Dollars	$5,193
									Hours	95.0



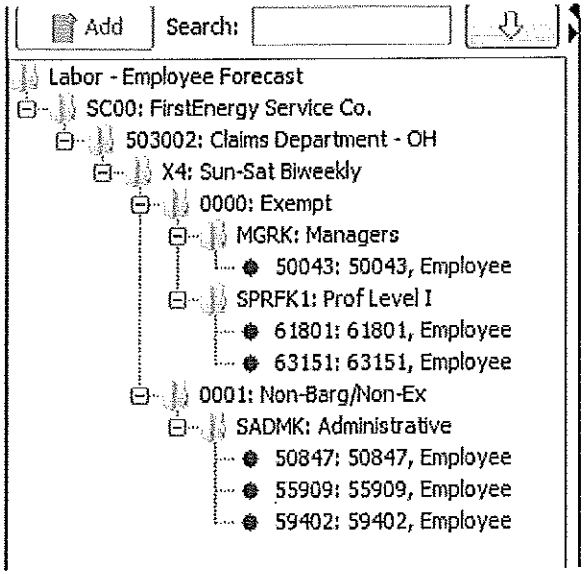
Column Totals	Dollars	$247,939
	Hours	4,583.8
Available Amounts	Available Hours	0.0

- Subtotal for SLINE2 will display and total on the available amounts row
- As hours are activity allocated out the available hours row will adjust

Budget Grid - How to Handle Labor Dollars/Hours

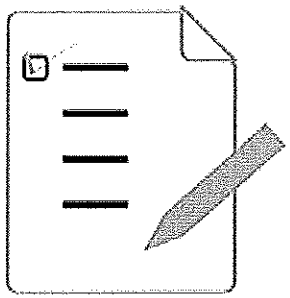
After the labor pool has been built:

- View the labor and hour report which will show the total calculated hours and dollars by activity type for each cost center
- Open the Budget Grid:
  - If labor has been allocated from your cost center, verify that the total labor pool matches the pool calculated in the **Summary Forecast**
  - Next users can start activity allocating labor hours and dollars.



Note: The Budget Grid is only for allocating hours and dollars. It will not show the labor dollars and hours allocated to the primary cost center.

Exercise #5 – Employee Labor



- Select a cost center and review an individual employee labor profile

- Under the Employee Attribute tab:
  - Transfer an employee
  - Exit an employee

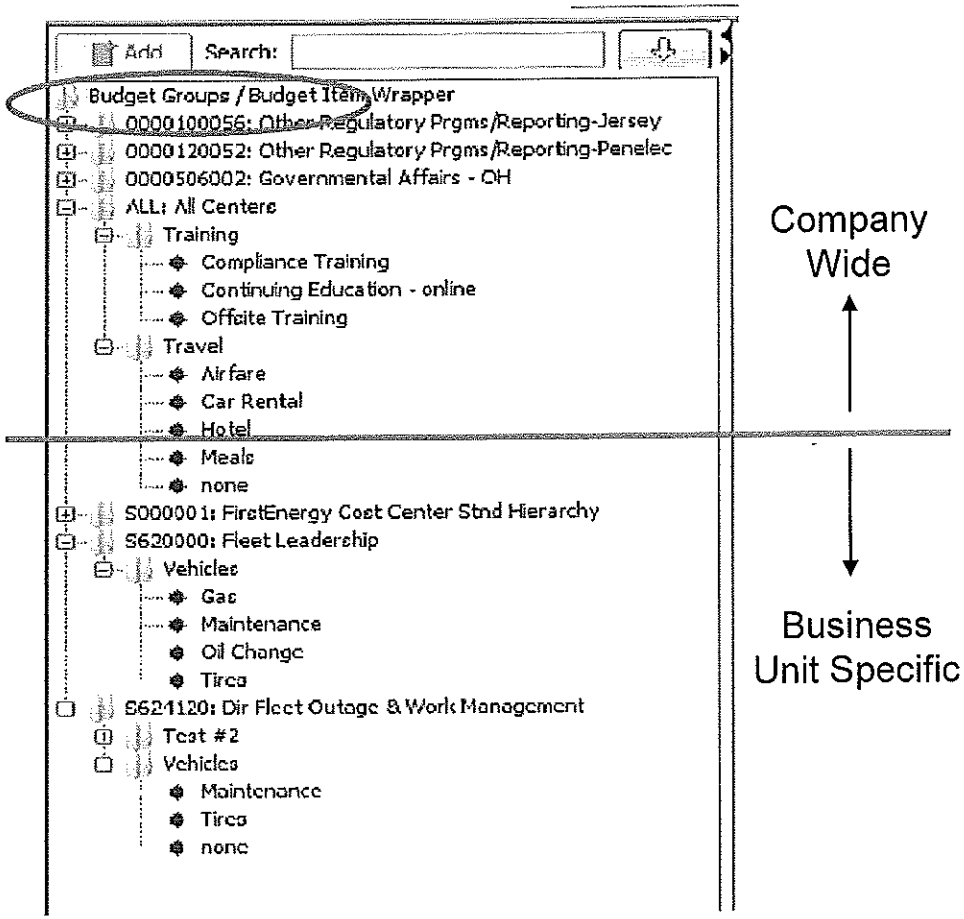
- Under the Calculation: Labor Budget Employee Forecast
  - Add a salary adjustment on the screen
  - Enter vacation and PAD allocations

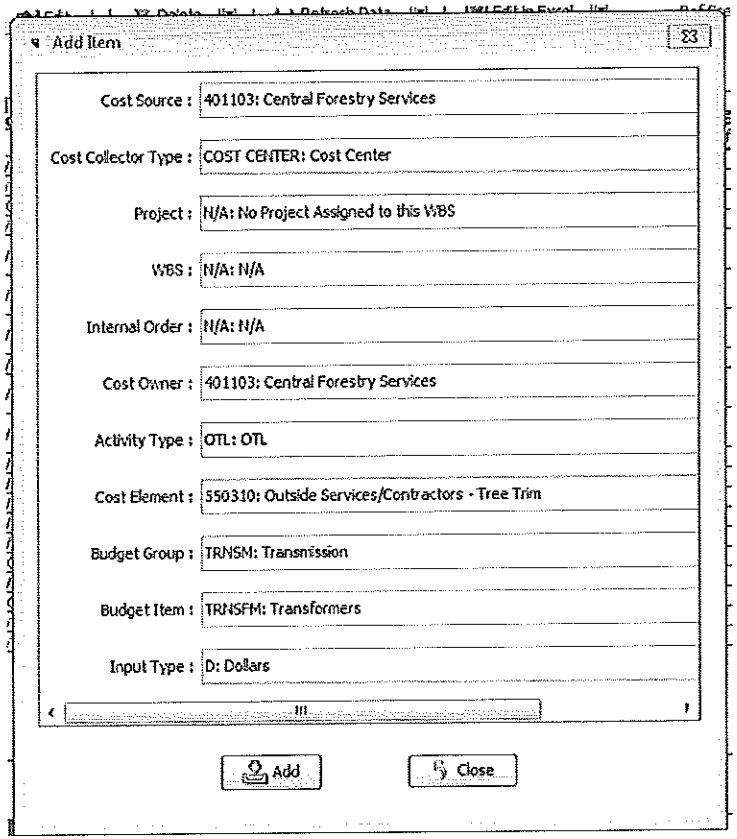
- View Summary Wrapper
  - Add a salary adjustment on the screen
  - Enter vacation and PAD allocations

Budget Group / Budget Item Wrapper

Budget Group / Budget Item Wrapper Overview

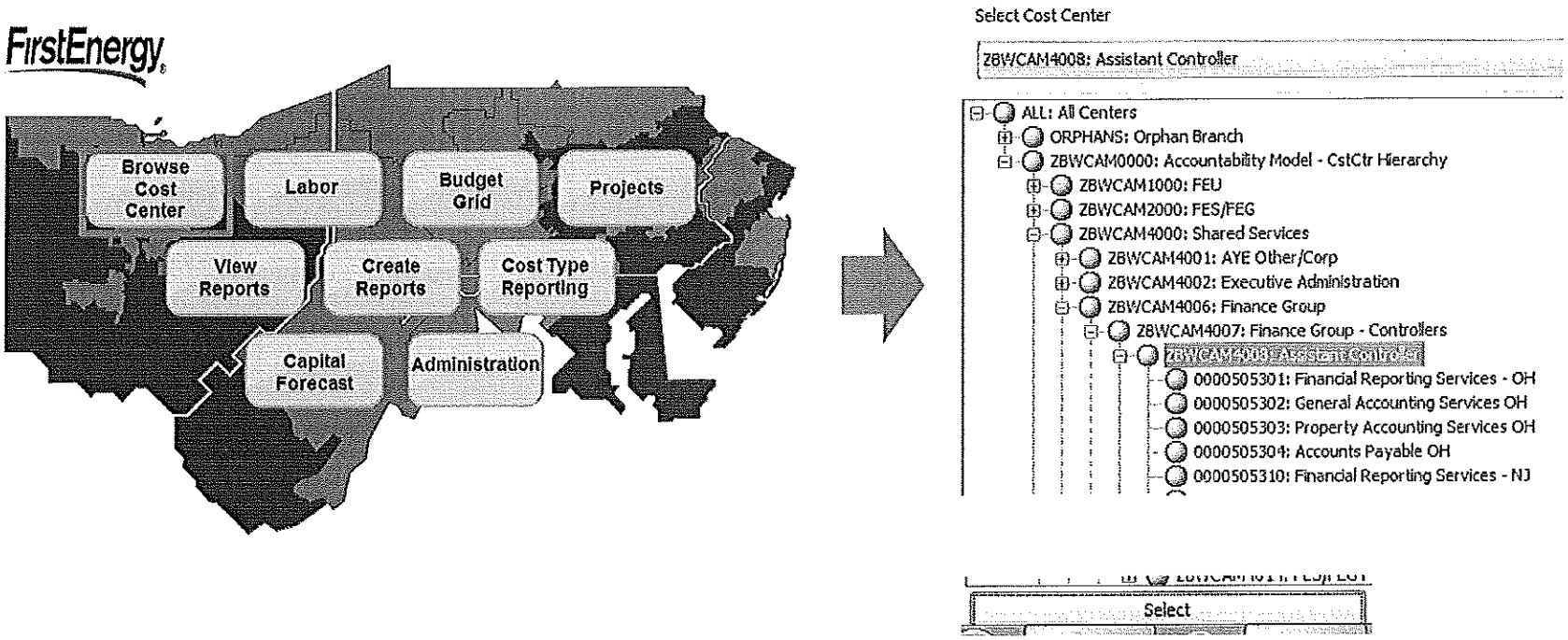
- Standard Budget Group and Budget Item groupings will be made available for all users
- Specific business unit budget groups and items can easily be created
- Ability to create Budget Group and Budget Item at the Cost Center level
- Business Unit/Department Budget Coordinators will create and maintain Budget Groups and Budget Items for their areas





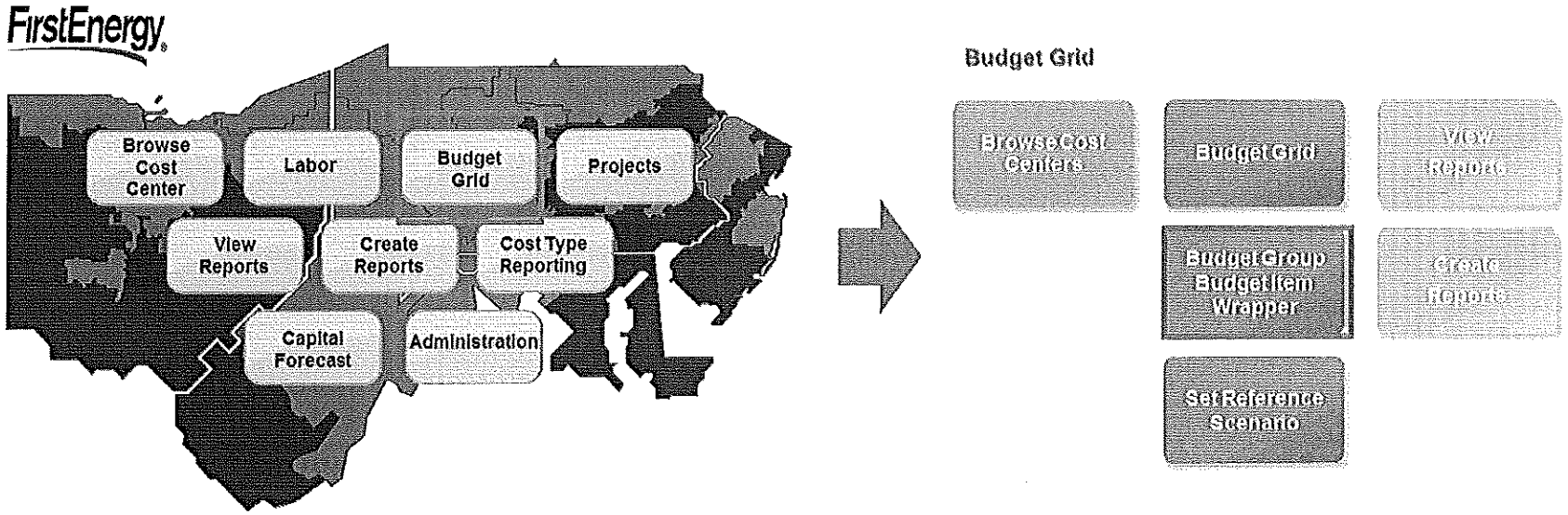
Budget Group / Budget Item Wrapper Startup

1. Using the Budget Group/Budget Item Wrapper
   - Open **FE Main Switchboard**
   - Select a Cost Center using **Browse Cost Centers** (either double-click a Cost Center or highlight Cost Center and click the Select button at the bottom of the screen)
   - NOTE: Any Budget Group/Budget Item assigned to a rollup node will be available for use for any Cost Center children of this node



Budget Group / Budget Item Wrapper Startup

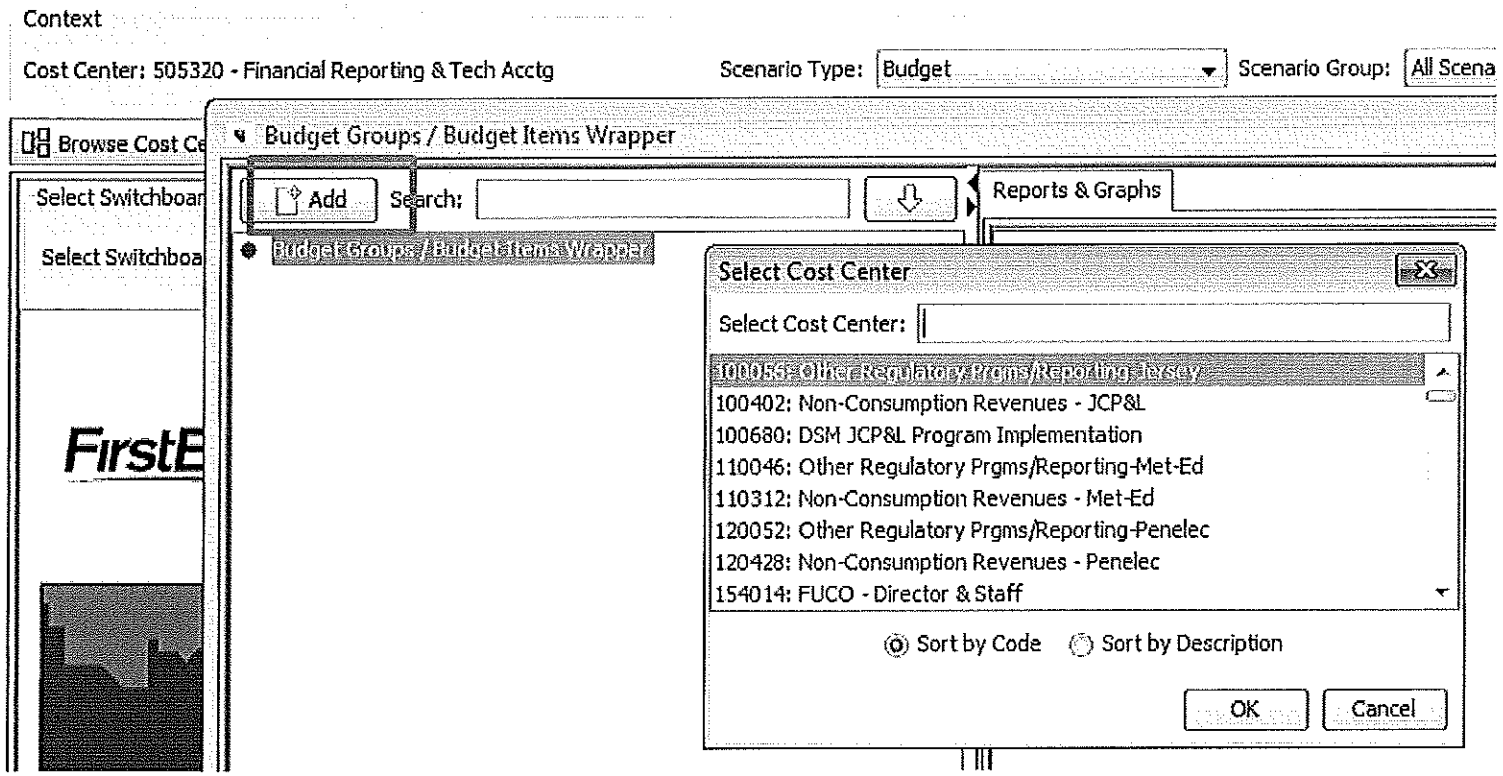
2
- Return to the **FE Main Switchboard**
- Click **Budget Grid**
- Click **Budget Group Budget Item Wrapper**



Adding a Cost Center

3

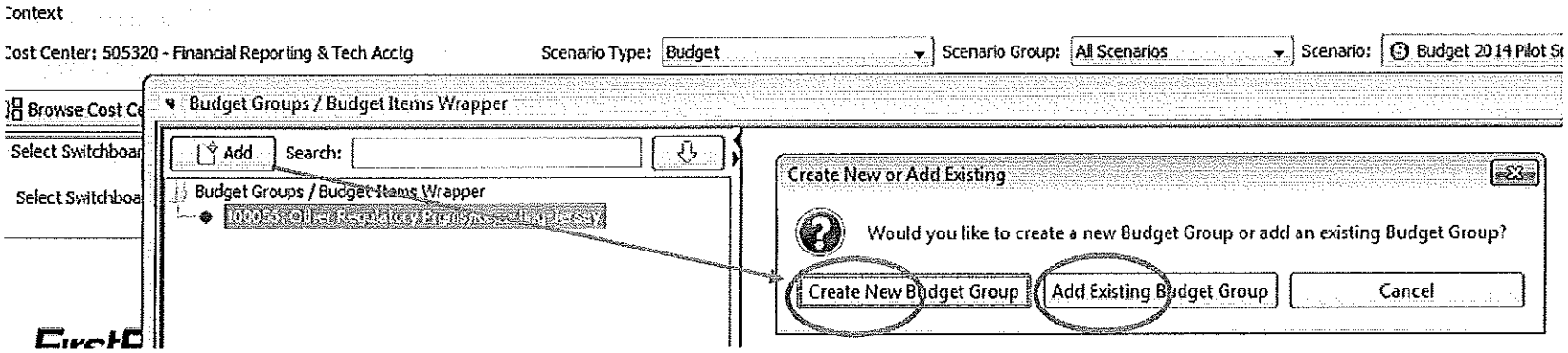
- If the Wrapper Tree is empty and no Cost Center is readily available, select "Budget Groups / Budget Items Wrapper" and click on the Click the **Add** button.
- Scroll through the list of Cost Centers and select one (use Select Cost Center window to search). Click **OK** when finished.



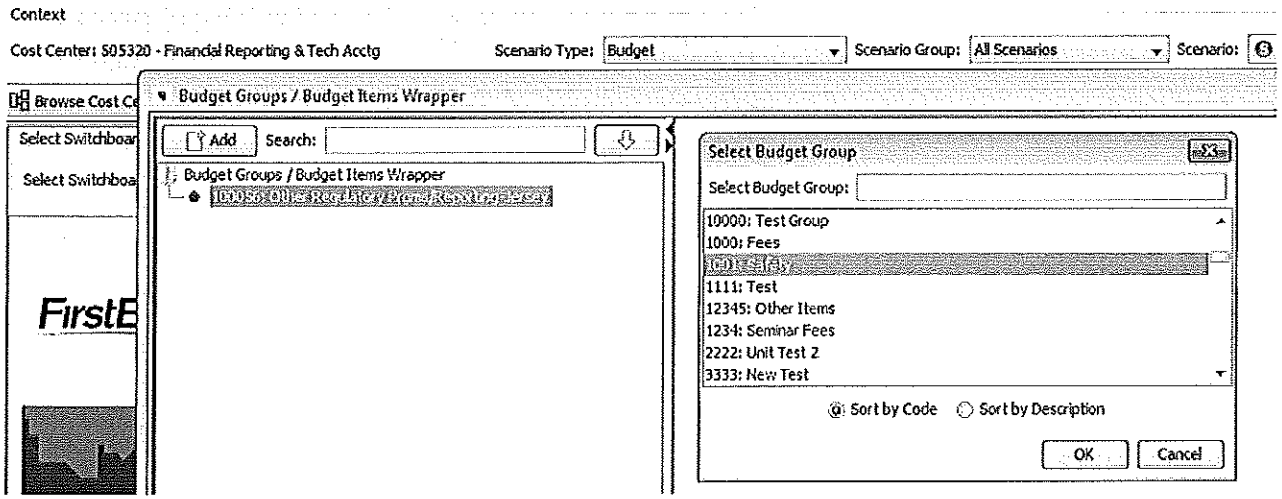
Add Existing Budget Group

4

- Select the Cost Center where a Budget Group and its associated Budget Item will be added and click **Add** button.
- Select either "Create New" or "Add Existing" Budget Group.



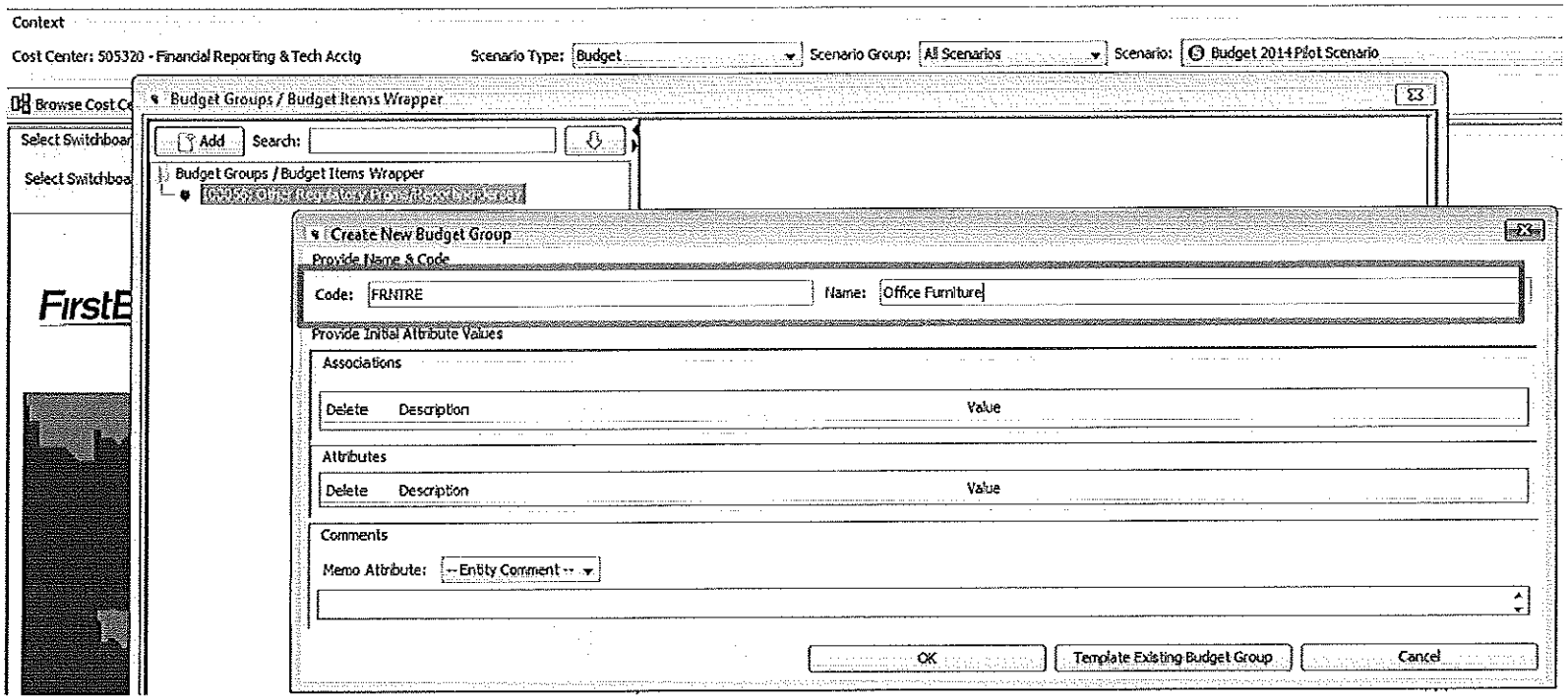
- If adding an existing Budget Group, simply select from the popup window and click **OK**.



Create a New Budget Group

4

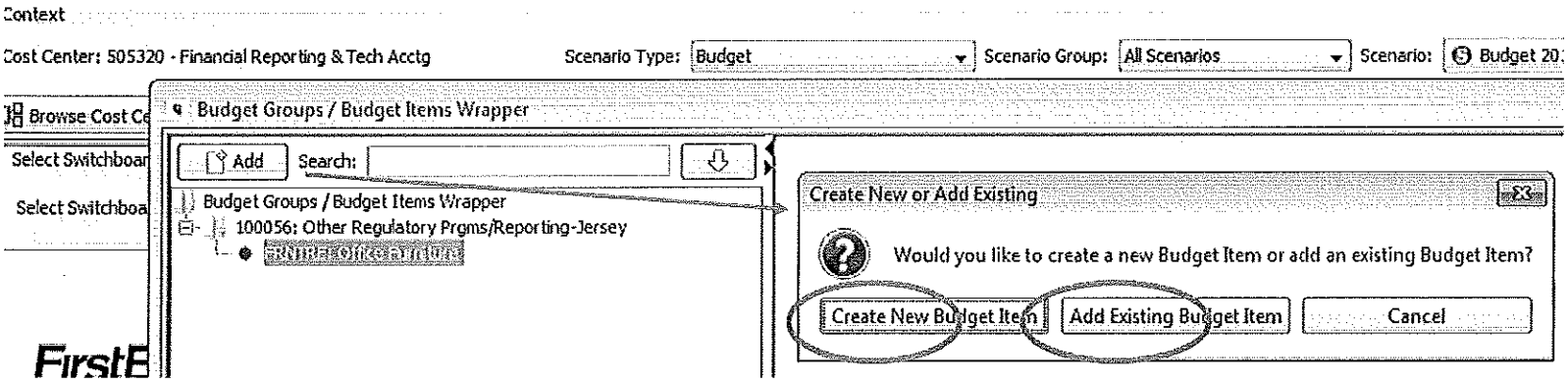
- Enter a unique Budget Group Code using process as defined by FE.
- Enter Name of Budget Group (MAX length = 80 characters)
- Click **OK**.



Adding / Creating Budget Items

5

- Follow a similar process for creating or adding Budget Items
- NOTE: Budget Items must have an associated Budget Group



Budget Group / Budget Item Guidelines

- Budget Coordinators will have the ability to create Budget Groups Budget and Items for their respective areas

Guidance on codes and names

• **Budget Group Budget Item Codes**	• **ALL CAPS** • **Up to 12 alpha characters**
• **Budget Group Budget Item Descriptions**	• **Upper and lower case** • **Up to 80 characters in length**

Example

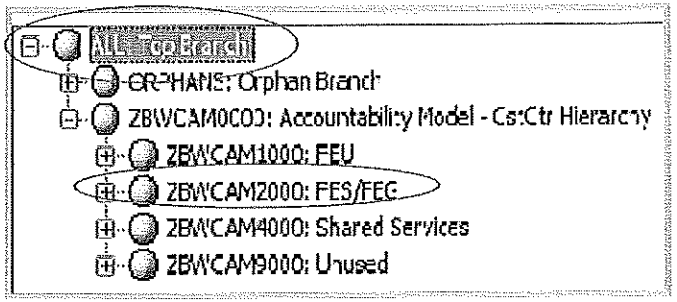
Budget Group	• **TRAIN**	**Training**
Budget Items	• SAFETY	Safety
	• COMPL	Compliance
	• OPER	Operations
	• CONTEDU	Continuing Education

Avoid creating similar Budget Groups and Budget Items

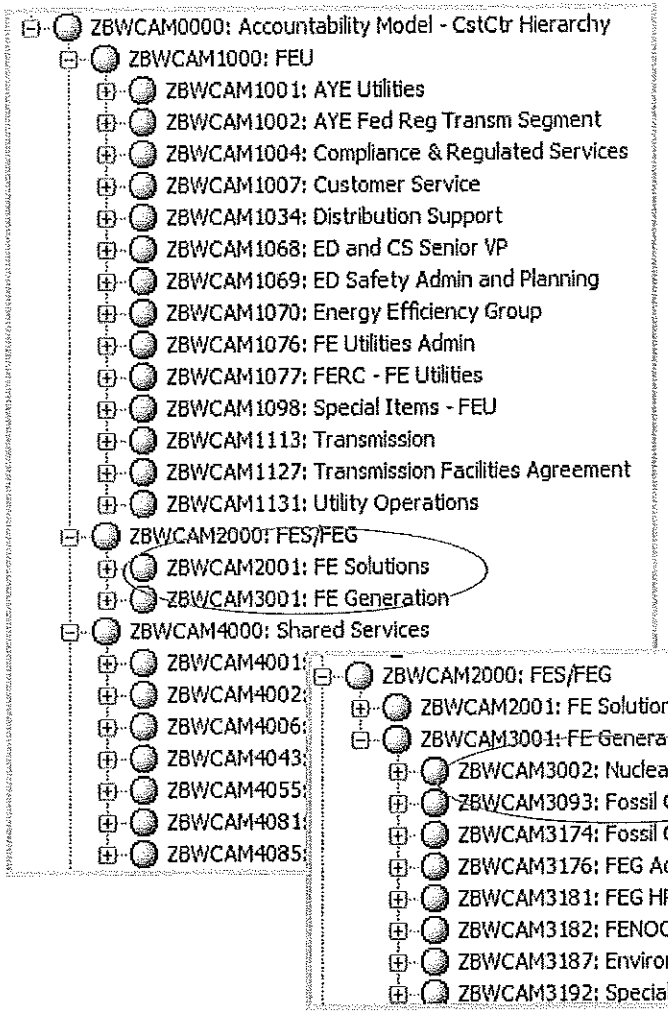
- Codes should be meaningful so when the accounting name is turned off on the Budget Grid the user can easily identify the Budget Group and Budget Item

Budget Group / Budget Item Guidelines

1. Budget Group / Budget Items will be created at the ALL NODE (created by Budget Administrator) and the Business Unit level (created by the Budget Coordinator)



2. Budget Groups / Budget Items can also be created at the <u>second</u> and <u>third</u> levels of the cost center tree



Note:

- **<u>DO NOT</u>** create budget groups and budget items at the cost center level

Normalizing Entries

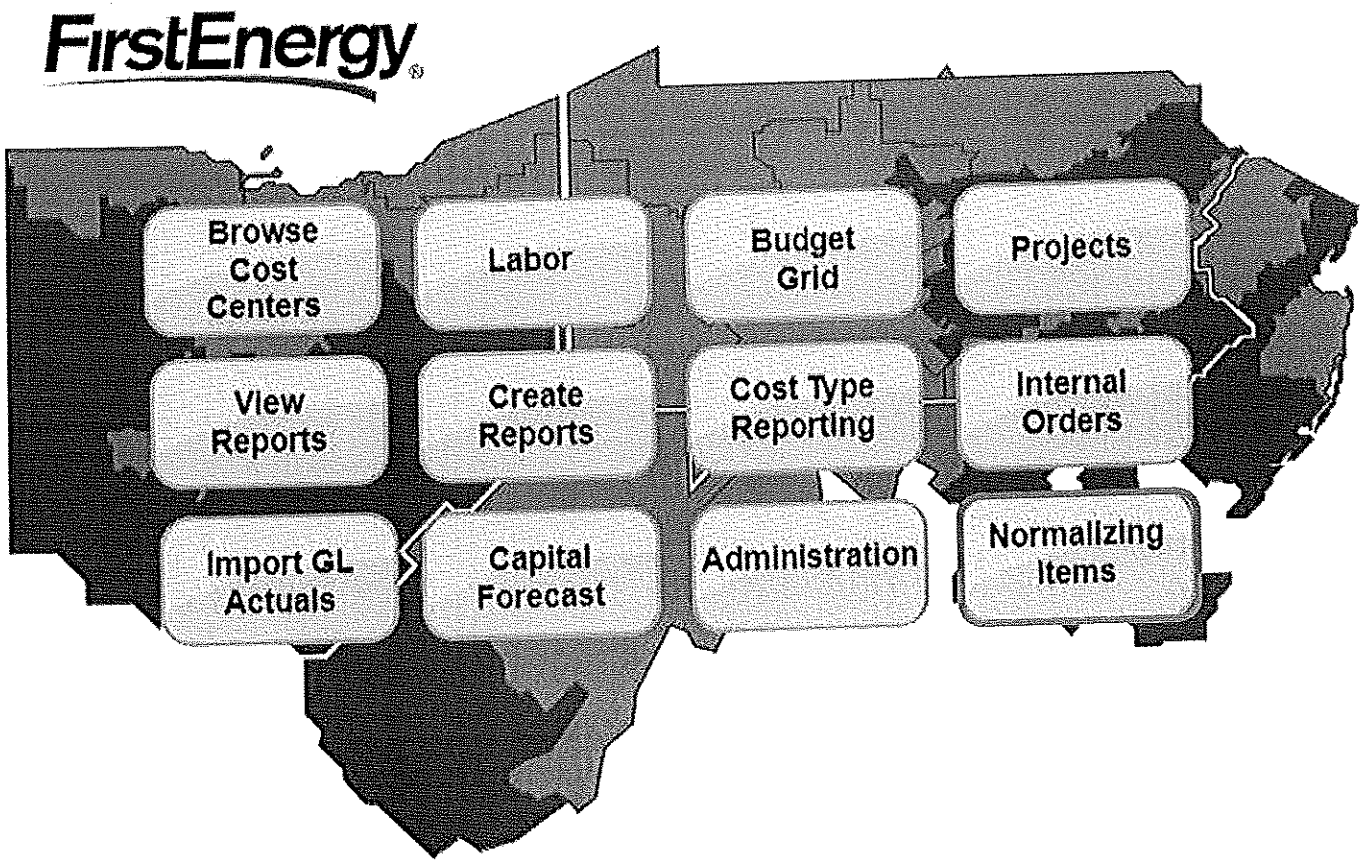
Normalizing Items

- **Normalizing Items**
  - Separate grid for normalized items
  - Normalized items will be applied to budget <u>after</u> closing process
  - GAAP budget and normalized items will be sent to the model, taxes will then be calculated by the model
  - Normalized budget will then be sent to BW

Note: The new budget entry process in UIP will be on a GAAP basis

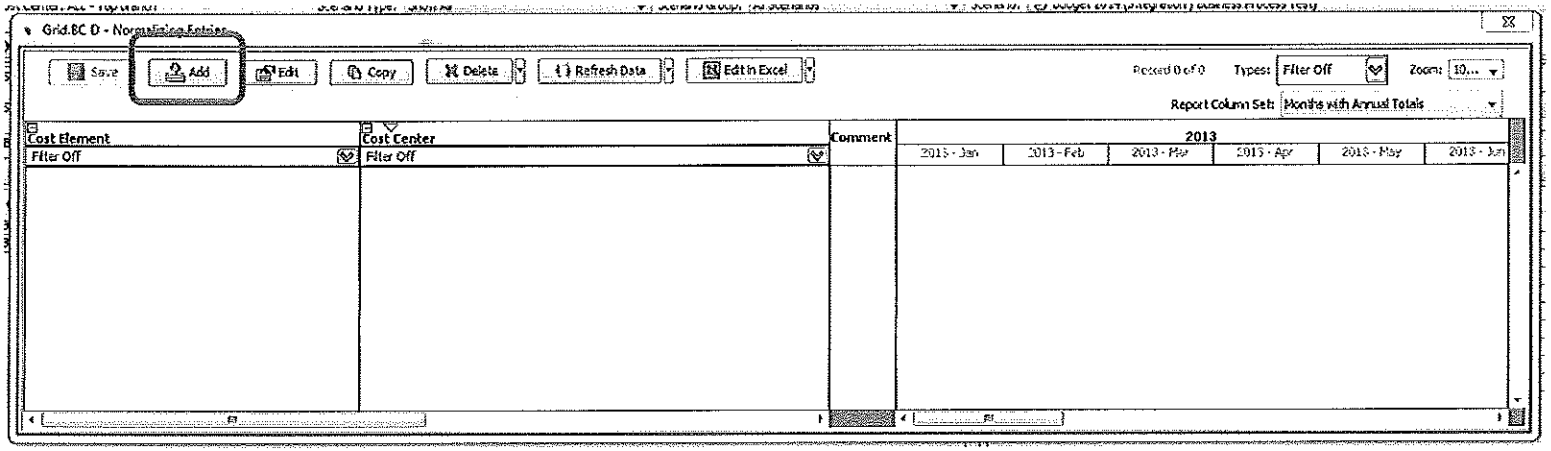
Normalizing Items

- From the Switchboard, select 'Normalizing Items'

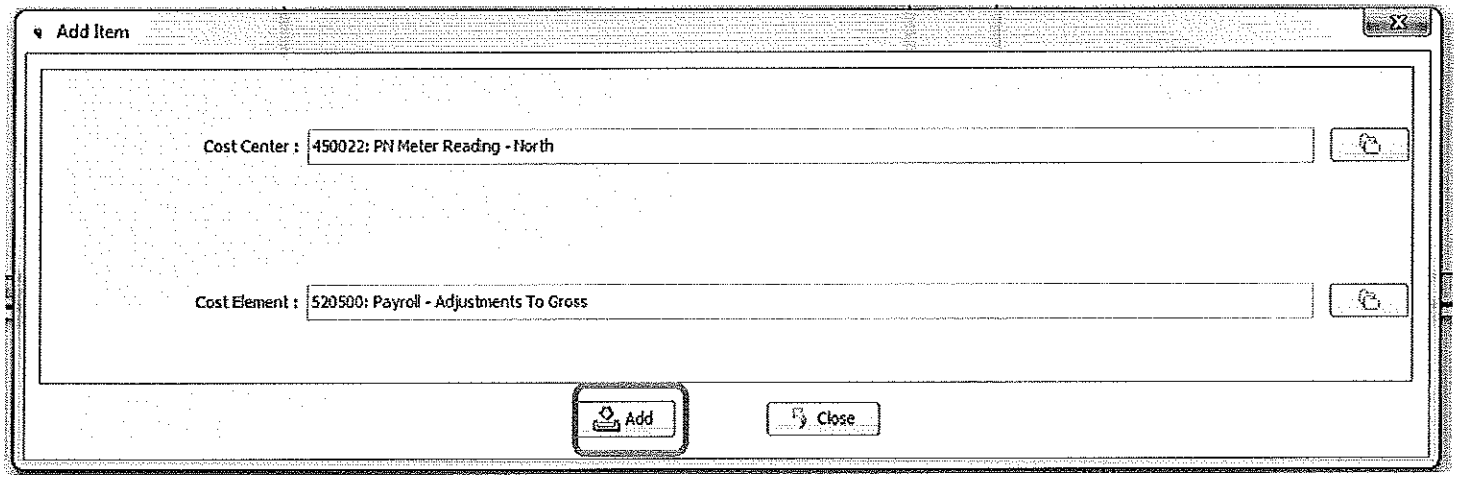


Normalizing Items

- The window below will open from the switchboard. Click Add to assign the code block.

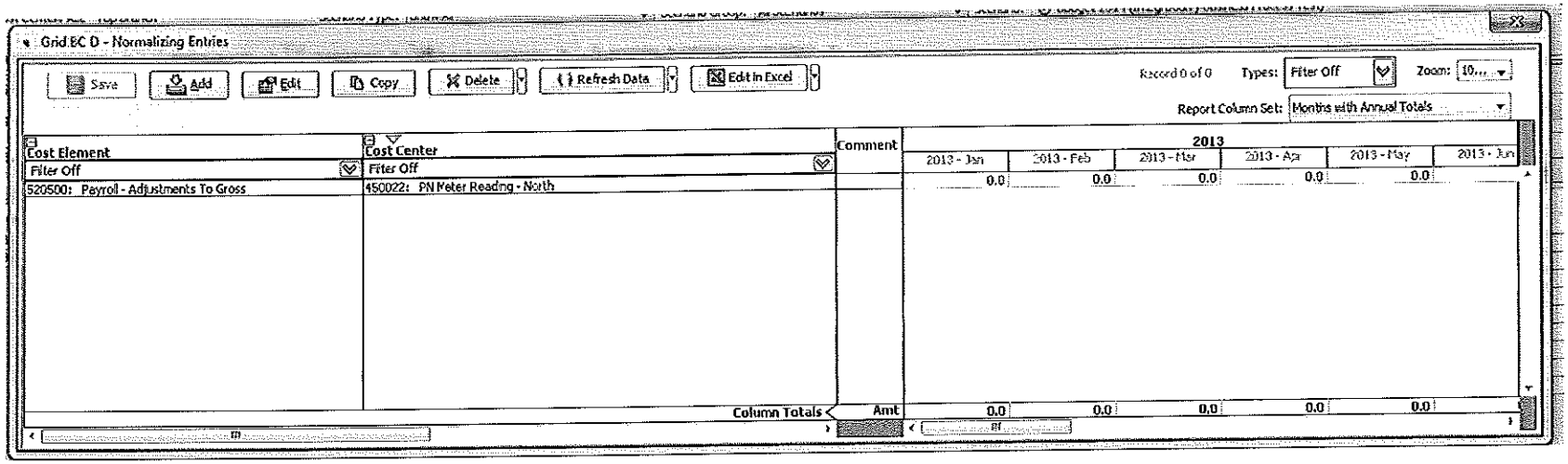


- Users can assign the Cost Center and Cost Element. Then click Add to save to grid.



Normalizing Items

- The new code block combination will be applied to the grid
- User can then update dollars in grid for entries



- Or, users can Edit in Excel to add rows…just like the usual grid.

Reference Materials

Commonly Used Terms in UIPlanner

Attribute
- Facts about an entity. Attributes are assigned to the Entity Group. Attribute data is then entered for each entity

B2
- The internal name given to the multidimensional calculation budget system when it was first developed (UIPlanner's second generation budget system)

Codeblock
- Codeblock consists of the budget grid data fields (cost source, cost owner, cost collector type, cost element, activity type, etc.)

Combo
- A budget data entry, comprised of the required code block elements

Cost Owner
- Owning cost center of the cost collector

Cost Source
- Cost Center where employee labor resides

Entities
- Building blocks for structured data within UIPlanner. Entities are specific elements of an Entity Group. Example: Generation plants are "Entities" in the Generation Entity Group

Commonly Used Terms in UIPlanner

Financial Model
- UIPlanner's modeling tool. Generates the key financial statements (income statement, balance sheet, cash flow)

Grid
- Budget Grid where users can allocate labor and other than labor. The Grid requires valid codeblock for entry

Java Console
- Java window that echoes back information about the user's UIPlanner session, including java error messages. Also known as the Stack Trace

Menu Item
- Row at the top of the UIPlanner screen contains menu items. Each menu item contains a drop list of screens or options

Scenario
- Scenarios are essentially collections of cases. Similar to SAP versions (V20, V12, etc.), but can be in various formats (Name, Description, etc.)

Switchboard
- Graphical object with hotspots that invoke actions in UIPlanner. Hot-spott areas on a switchboard and can open menu items, run reports, open files, and open other switchboards

Commonly Used Terms in UIPlanner

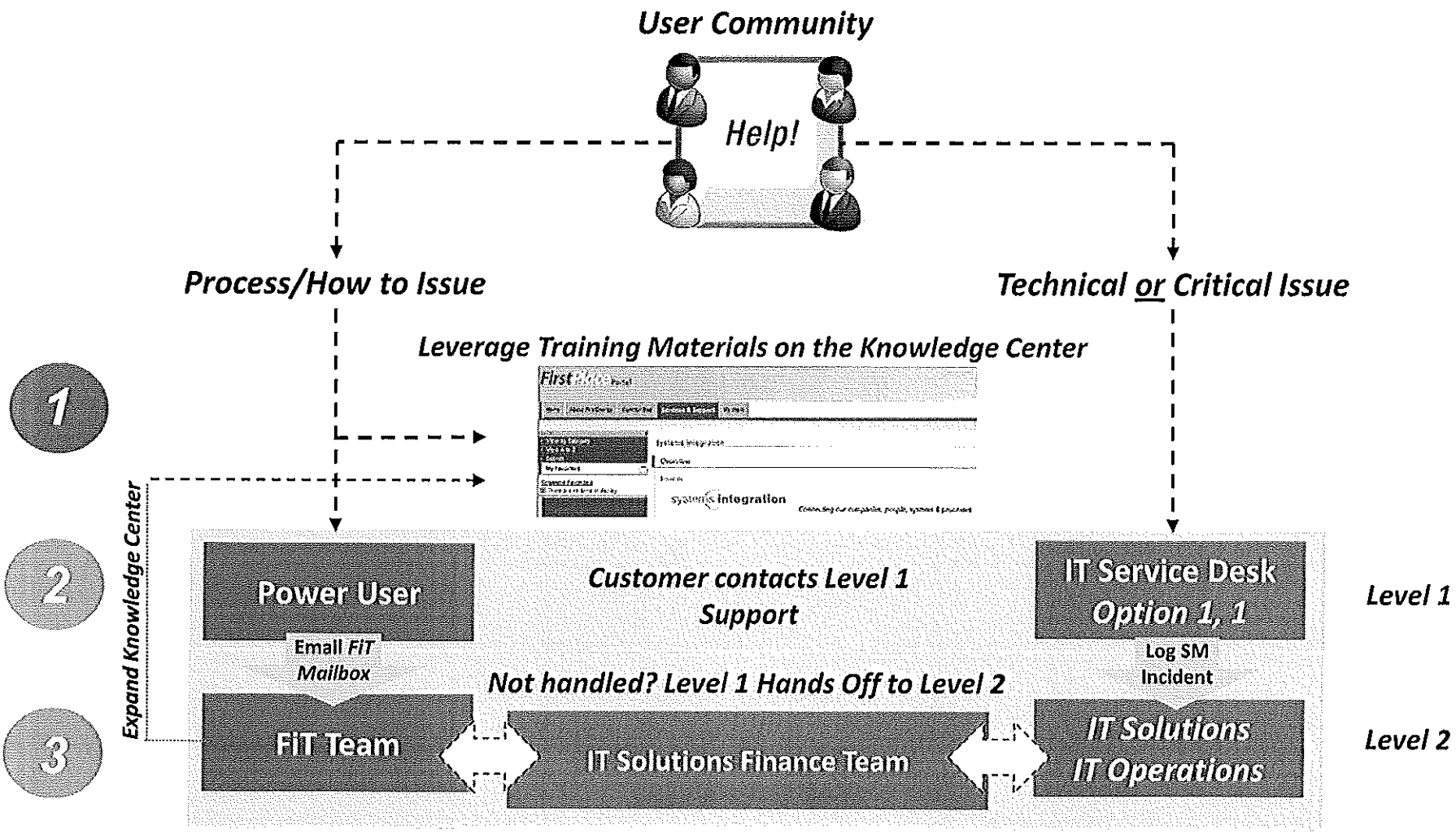
UIPlanner Add In

- **UIPlanner utilizes an Excel Add In function**

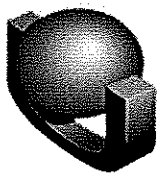
Wrapper

- **An interface that is built to present a calculation to the end user in a more user-friendly fashion**

Where do I go for help?



Thank You for Attending



UTILITIES
International

METROPOLITAN EDISON COMPANY

Original Cost of Plant, Reserves and Accruals by Functions for Fully Projected Future Test Year Ending 4/30/2016

FILING REQUIREMENT V-A-1:

"Provide schedules supporting claimed amounts for Electric Plant in Service by function and by account if available."

FILING REQUIREMENT V-A-2:

"Provide a comparison of calculated depreciation reserve versus book reserve at the end of the test year. Provide this comparison by functional group and by account if available."

FILING REQUIREMENT V-B-1:

"Provide a comparison of calculated depreciation accruals versus book accruals by function and by account if available."

FILING REQUIREMENT V-D-1:

"Provide the surviving original cost plant at the appropriated test year date or dates by account and functional property group and include claimed depreciation reserves. Provide annual depreciation accruals where appropriate. These calculations should be provided for plant in service as well as other categories of plant, including but not limited to, contributions in aid of construction, customers' advances for construction and anticipated retirements associated with construction work in progress claims, if applicable."

RESPONSE:

Met-Ed Exhibit RAD-46 Attachment A satisfies the filing requirements cited above. The accruals shown on Met-Ed Exhibit RAD-46 Attachment A are claimed remaining life accruals for booking.

Met-Ed Exhibit RAD-46 Attachment B provides original cost activity at detail account levels for plant and reserves, updating this information from 4/30/15 through 4/30/16, the fully projected future test year-end. Additionally, this exhibit shows the affected balances after net adjustments made for rate case purposes, and the affected balances after net adjustments. This information is in support of Met-Ed Exhibit RAD-46 Attachment A as follows:

Pages 1-2 Company claim basis for Electric Plant in Service reflecting projected plant at 4/30/16 and net adjustments thereto.

Pages 3-4 Company claim basis of book reserves for Electric Plant in Service at 4/30/16 and net adjustments thereto.

Pages 5 Informational calculated reserves at 4/30/16 for Electric Plant in Service and net adjustments thereto.

Metropolitan Edison Company
Accrual Expense Computation after Adjustments
At Future Year from May 2015 to April 2016

Line No.	Description	Adjusted Plant Balances			Book Depreciation Reserve	Depreciation Reserve Ratio	Net Uncovered Book Plant	Accrual Average Remaining Life Basis		Calculated Reserve	Book Reserve	Difference	Difference as a % of Calculated Reserve
		Non Depreciable	Depreciable	Total				Amount	Effective Rate				
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Transmission	-	-	-	-	0.00%	-	-	0.00%	-	-	-	0.00%
2	Distribution	3,205	2,046,714	2,049,919	623,728	30.43%	1,426,191	38,818	1.90%	507,318	623,728	(116,410)	-22.95%
3	General Plant	2,673	151,689	154,362	96,228	62.34%	58,133	5,994	3.95%	88,711	96,228	(7,518)	-8.47%
4	Subtotal	5,878	2,198,403	2,204,281	719,956	32.66%	1,484,324	44,812	2.04%	596,028	719,956	(123,928)	-20.79%
5	Intangible Plant	289	61,287	61,576	31,345	50.90%	30,231	8,069	13.17%	38,277	31,345	6,932	18.11%
6	Total	6,166	2,259,690	2,265,856	751,301	33.16%	1,514,555	52,881	2.34%	634,306	751,301	(116,996)	-18.44%
	Exhibit Reference	RAD-46 Attachment B P 1-2	RAD-46 Attachment B P 1-2	RAD-46 Attachment B P 1-2	RAD-46 Attachment B P 3-4			RAD-53 Attachment A P 1-2		RAD-46 Attachment B P 5-6	RAD-46 Attachment B P 3-4		

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 4/30/15 to 4/30/16
Plant-In-Service

Acct No	Description	Balance 4/30/15	Budget Activity: Additions	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 4/30/16	Adjustments	Adjusted Balance 4/30/16
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	NONDEPRECIABLE PLANT							
	Intangible Plant							
301	Organization	$ 123,507	$ -	$ -	$ -	$ 123,507	$ -	$ 123,507
302	Franchise And Consents	165,169	-	-	-	165,169	-	165,169
	Total Intangible Plant	$ 288,676	$ -	$ -	$ -	$ 288,676	$ -	$ 288,676
	Land							
350.11	Transmission Substations	$ 1,384,344	$ -	$ -	$ -	$ 1,384,344	$ (1,384,344)	$ -
350.21	Transmission Lines	2,045,027	-	-	-	2,045,027	(2,045,027)	-
360.11	Distribution Substations.	2,777,235	-	-	-	2,777,235	-	2,777,235
360.21	Distribution Lines	427,642	-	-	-	427,642	-	427,642
389.1	General	2,672,808	-	-	-	2,672,808	-	2,672,808
	Total Land	$ 9,307,056	$ -	$ -	$ -	$ 9,307,056	$ (3,429,372)	$ 5,877,684
	TOTAL NON-DEPRECIABLE PLAN	$ 9,595,732	$ -	$ -	$ -	$ 9,595,732	$ (3,429,372)	$ 6,166,360
	INTANGIBLE PLANT							
303	Misc. Intangible Plant	$ 41,619,083	$ 16,259,071	$ -	$ -	$ 57,878,154	$ (9,694,591)	$ 48,183,564
303	Smart Meter Software	2,249,535	10,853,984	-	-	13,103,518	-	13,103,518
	TOTAL INTANGIBLE PLANT	$ 43,868,618	$ 27,113,055	$ -	$ -	$ 70,981,673	$ (9,694,591)	$ 61,287,082
	NUCLEAR PRODUCTION							
	Nuclear Production							
326	Asset Retirement Costs Nuclear	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TOTAL NUCLEAR PRODUCTION	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TRANSMISSION PLANT							
	TRANSMISSION PLANT							
350.12	Easements - Trans. Subs.	$ 173,374	$ -	$ -	$ -	$ 173,374	$ (173,374)	$ -
350.22	Easements - Trans. Lines	26,760,119	-	-	-	26,760,119	(26,760,119)	-
352.1	Structures, Improvements	6,475,002	-	-	-	6,475,002	(6,475,002)	-
352.2	Clearing, Grading Of Land	304,599	-	-	-	304,599	(304,599)	-
353	Station Equipment	194,644,237	17,706,171	(1,770,617)	-	210,579,791	(210,579,791)	-
354	Towers And Fixtures	41,082,524	-	-	-	41,082,524	(41,082,524)	-
355	Poles And Fixtures	46,549,680	-	-	-	46,549,680	(46,549,680)	-
356.1	Overhd Conductr, Devices	94,554,236	5,143,215	(514,322)	-	99,183,130	(99,183,130)	-
356.2	Clearing, Grading of Land	17,682,895	-	-	-	17,682,895	(17,682,895)	-
358	Undergrnd Conductr,Devices	1,191,163	-	-	-	1,191,163	(1,191,163)	-
359	Roads And Trails	746,971	-	-	-	746,971	(746,971)	-
359.1	ARC Transmission	4,666	-	-	-	4,666	(4,666)	-
	TOTAL TRANSMISSION PLANT	$ 430,169,466	$ 22,849,386	$ (2,284,939)	$ -	$ 450,733,913	$ (450,733,913)	$ -
	DISTRIBUTION PLANT							
360.12	Easements - Dist. Subs.	$ 611,470	$ -	$ -	$ -	$ 611,470	$ -	$ 611,470
360.22	Easements - Dist. Lines	28,320,720	-	-	-	28,320,720	-	28,320,720
361.1	Structures, Improvements	12,746,076	-	-	-	12,746,076	-	12,746,076
361.2	Clearing, Grading of Land	366,045	-	-	-	366,045	-	366,045
362	Station Equipment	213,272,785	3,916,600	(391,660)	-	216,797,725	-	216,797,725
364	Poles, Towers And Fixtures	354,210,686	-	-	-	354,210,686	-	354,210,686
365	Overhd Conductr, Devices	368,193,014	-	-	-	368,193,014	-	368,193,014
365.1	Clearing, Grading of Land	131,739,866	-	-	-	131,739,866	-	131,739,866
366	Underground Conduit	30,296,760	-	-	-	30,296,760	-	30,296,760
367	Undergrnd Conductr,Devices	203,212,529	-	-	-	203,212,529	-	203,212,529
368	Line Transformers	453,921,791	53,715,097	(5,371,510)	-	502,265,379	-	502,265,379
369	Services OH	71,066,339	-	-	-	71,066,339	-	71,066,339
369	Unground Services	98,458,792	-	-	-	98,458,792	-	98,458,792
370	Meters	66,794,533	-	-	-	66,794,533	(66,794,533)	-
370	Smart Meters Res	2,470,358	10,166,426	(1,016,643)	-	11,620,142	-	11,620,142
371	Inst. On Cust. Prem.	4,519,593	-	-	-	4,519,593	-	4,519,593
373.1	Street Light - Oh, Ug Lines	12,289,135	-	-	-	12,289,135	-	12,289,135

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 4/30/15 to 4/30/16
Plant-In-Service

Acct No	Description	Balance 4/30/15	Budget Activity Additions	Retirements	Transfers/ Adjustments	Balance 4/30/16	Adjustments	Adjusted Balance 4/30/16
374	ARC Distribution	37,210	-	-	-	37,210	(37,210)	-
	TOTAL DISTRIBUTION PLANT	$ 2,052,527,703	$ 67,798,124	$ (6,779,812)	$ -	$ 2,113,546,014	$ (66,831,743)	$ 2,046,714,271
	GENERAL PLANT							
389.2	Easements	$ 18,078	$ -	$ -	$ -	$ 18,078	$ (3,028)	$ 15,050
390.1	Structures, Improvements	87,468,165	442	(44)	-	87,468,562	(14,650,984)	72,817,578
390.2	Clearing, Grading of Land	12,466,282	-	-	-	12,466,282	(2,088,102)	10,378,180
390.3	Struct Imprv, Leasehold Imp	16,754	-	-	-	16,754	(2,806)	13,948
391.1	Office Furn., Mech. Equip.	16,630,775	-	-	-	16,630,775	(2,785,655)	13,845,120
391.15	Office Machines	5,920,633	-	-	-	5,920,633	(991,706)	4,928,927
391.2	Data Processing Equipment	4,626,945	-	-	-	4,626,945	(775,013)	3,851,932
391.25	Data Proc Smart Meters	6,503,330	3,106,583	(310,658)	-	9,299,254	-	9,299,254
391.25	Information System	(11,738)	-	-	-	(11,738)	1,966	(9,772)
392	Transportation Equipment	4,272,477	1,013,658	(101,366)	-	5,184,769	(868,449)	4,316,320
393	Stores Equipment	1,411,422	-	-	-	1,411,422	(236,413)	1,175,009
394	Tools, Shop, Garage Equip.	11,711,828	-	-	-	11,711,828	(1,961,731)	9,750,097
395	Laboratory Equipment	3,047,684	-	-	-	3,047,684	(510,487)	2,537,197
396	Power Operated Equipment	751,658	-	-	-	751,658	(125,903)	625,755
397	Communication Equipment	34,023,088	-	-	-	34,023,088	(18,032,237)	15,990,851
398	Misc. Equipment	2,586,560	-	-	-	2,586,560	(433,249)	2,153,311
399.1	ARC General Plant	105,951	-	-	-	105,951	(105,951)	-
	TOTAL GENERAL PLANT	$ 191,549,891	$ 4,120,682	$ (412,068)	$ -	$ 195,258,505	$ (43,569,748)	$ 151,688,757
	TOTAL	$ 2,823,032,564	$ 121,881,247	$ (9,476,819)	$ -	$ 2,935,436,992	$ (669,580,522)	$ 2,265,856,470

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 4/30/15 to 4/30/16
Book Reserves

Acct No	Description	Balance 4/30/15	Budget Activity: Accruals	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 4/30/16	Adjustments	Adjusted Balance 4/30/16
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	INTANGIBLE PLANT							
303	Software	$ 32,950,380	$ 2,943,599	$ -	$ -	$ 35,893,979	$ (6,012,241)	$ 29,881,737
303	Smart Meters	138,941	1,324,287	-	-	1,463,228	-	1,463,228
	TOTAL INTANGIBLE PLANT	$ 33,089,321	$ 4,267,886	$ -	$ -	$ 37,357,207	$ (6,012,241)	$ 31,344,965
	TRANSMISSION PLANT							
350.12	Tran Sub Easement	$ 107,583	$ 2,602	$ -	$ -	$ 110,185	$ (110,185)	$ -
350.21	Tran Line Land	7,848	-	-	-	7,848	(7,848)	-
350.22	Tran Line Easement	11,872,776	401,540	-	-	12,274,316	(12,274,316)	-
352	Struct PCA Dist	68,303	2,030	-	-	70,333	(70,333)	-
352	Structures/improve	2,790,137	122,101	-	-	2,912,238	(2,912,238)	-
353	Station Eq PCA Dist	2,227,677	137,587	-	-	2,365,264	(2,365,264)	-
353	Station equipment	56,081,740	3,297,645	(1,770,617)	-	57,608,768	(57,608,768)	-
354	Towers & Fixtures	27,230,294	486,478	-	-	27,716,772	(27,716,772)	-
354	Towers PCA Dist	33,799	453	-	-	34,252	(34,252)	-
355	Poles & Fixtures	18,306,343	656,833	-	-	18,963,176	(18,963,176)	-
355	Poles PCA Dist	394,900	8,518	-	-	403,418	(403,418)	-
356	OH Cond PCA Dist	296,153	6,740	-	-	302,893	(302,893)	-
356	Overhead Conductor	27,640,699	1,240,072	(514,322)	-	28,366,449	(28,366,449)	-
356.1	0 Clearing & R/W	3,094,640	90,356	-	-	3,184,996	(3,184,996)	-
356.1	0 R/W PCA Dist	782,274	146,557	-	-	928,831	(928,831)	-
356.2	0 Veg Clrng-FERC exp	-	-	-	-	-	-	-
358	UG Cond PCA Dist	309	48	-	-	357	(357)	-
358	Undergound Conductor	100,517	29,198	-	-	129,715	(129,715)	-
359	Roads & Trails	526,877	16,548	-	-	543,425	(543,425)	-
359	Roads PCA Dist	7,998	268	-	-	8,266	(8,266)	-
359.1	TXM SUB ARC	2,727	104	-	-	2,831	(2,831)	-
	TOTAL TRANSMISSION PLANT	$ 151,573,594	$ 6,645,678	$ (2,284,939)	$ -	$ 155,934,333	$ (155,934,333)	$ -
	DISTRIBUTION PLANT							
360.12	Dist Sub Easement	$ 182,521	$ 9,004	$ -	$ -	$ 191,525	$ -	$ 191,525
360.22	Dist Line Easement	14,418,605	417,008	-	-	14,835,613	-	14,835,613
361	Structure/Improve	6,252,488	313,866	-	-	6,566,354	-	6,566,354
361.2	Grading Clearing	24,386	9,014	-	-	33,400	-	33,400
362	Station equipment	73,880,311	3,312,439	(391,660)	-	76,801,090	-	76,801,090
364	Poles towers fix	109,277,922	4,769,507	-	-	114,047,429	-	114,047,429
365	Overhead conductor	81,413,698	6,143,661	-	-	87,557,359	-	87,557,359
365.1	Clearing & R/W	19,108,306	2,011,562	-	-	21,119,868	-	21,119,868
366	Underground conduit	11,421,375	529,030	-	-	11,950,405	-	11,950,405
367	Undergrd conductor	72,497,543	5,794,026	-	-	78,291,569	-	78,291,569
368	Line Transformers	128,116,708	10,229,065	(5,371,510)	-	132,974,263	-	132,974,263
369	Services OH	19,854,015	1,638,032	-	-	21,492,047	-	21,492,047
369	Unground Services	48,920,654	2,219,858	-	-	51,140,512	-	51,140,512
370	Meters	14,928,912	2,719,479	(1,016,643)	-	16,631,748	(16,631,748)	-
370	Smart Meters Res	171,958	327,423	-	-	499,381	-	499,381
371	Inst on cust prem	1,988,534	123,663	-	-	2,112,197	-	2,112,197
371	Meter Socket dvc 125	186	8	-	-	194	-	194
371	Meter Socket dvc 126	186	8	-	-	194	-	194
371	Meter Socket dvc 127	377	15	-	-	392	-	392
371	Meter Socket dvc 1PH	315,679	13,242	-	-	328,921	-	328,921
371	Meter Socket dvc 3PH	270	11	-	-	281	-	281
371	Surge Suppression 2	240,849		-	-	240,849	-	240,849
371	Surge Suppression 4	35,859		-	-	35,859	-	35,859
373	Street Lighting	3,187,111	321,122	-	-	3,508,233	-	3,508,233
374	DIST SUB ARC	22,253	759	-	-	23,012	(23,012)	-
	TOTAL DISTRIBUTION PLANT	$ 606,260,706	$ 40,901,802	$ (6,779,813)	$ -	$ 640,382,695	$ (16,654,760)	$ 623,727,935

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 4/30/15 to 4/30/16
Book Reserves

Acct No	Description	Balance 4/30/15	Budget Activity: Accruals	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 4/30/16	Adjustments	Adjusted Balance 4/30/16
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	GENERAL PLANT							
389.2	Land Rights	$ 15,648	$ 407	$ -	$ -	$ 16,055	$ (2,689)	$ 13,365
390.1	Easton Serv Center	4,348,061	312,519	-	-	4,660,580	(780,647)	3,879,933
390.1	Lebanon Serv Ctr	3,322,094	187,671	-	-	3,509,765	(587,886)	2,921,879
390.1	South Bldg Reading	26,359,437	1,131,552	(44)	-	27,490,945	(4,604,733)	22,886,212
390.1	Structures	8,273,270	409,507	-	-	8,682,777	(1,454,365)	7,228,412
390.1	York Serv Center	4,210,591	209,705	-	-	4,420,296	(740,400)	3,679,896
390.2	Corp Hqtrs Reading	1,812,398	90,647	-	-	1,903,045	(318,760)	1,584,285
390.2	Easton Ser Ctr	999,764	116,782	-	-	1,116,546	(187,021)	929,525
390.2	Land/Yard Improvem	3,020,759	169,861	-	-	3,190,620	(534,429)	2,656,191
390.2	Lebanon Ser Ctr	818,850	23,374	-	-	842,224	(141,073)	701,152
390.2	York Ser Ctr	1,193,663	46,769	-	-	1,240,432	(207,772)	1,032,660
390.3	Transfered LH	5,201	838	-	-	6,039	(1,012)	5,028
391.1	Office Furniture	15,450,558	742,483	-	-	16,193,041	(2,712,334)	13,480,707
391.15	Office Machines	5,920,633		-	-	5,920,633	(991,706)	4,928,927
391.2	Personal Computers	3,094,514	788,606	-	-	3,883,120	(650,423)	3,232,698
391.25	Data Proc Smart Me	312,781	1,563,011	(310,658)	-	1,565,134	-	1,565,134
391.25	Information Sys	(7,464)	(4,172)	-	-	(11,636)	1,949	(9,687)
392	Transportation equip	111,732	29,749	-	-	141,481	(23,698)	117,783
392.4	Pole Trailers	488,498	25,554	-	-	514,052	(86,104)	427,948
392.5	Van Trailers	79,848	717	-	-	80,565	(13,495)	67,070
393	Stores Equipment	1,411,421	-	-	-	1,411,421	(236,413)	1,175,008
394	Tools shop garage	7,242,071	514,703	-	-	7,756,774	(1,299,260)	6,457,515
395	Laboratory equip	3,047,684	-	-	-	3,047,684	(510,487)	2,537,197
396	Power operated equip	617,698	4,230	-	-	621,928	(104,173)	517,755
397	Communication Equipt	24,679,661	1,078,092	(101,366)	-	25,656,387	(13,597,885)	12,058,502
398	Miscellaneous equipt	2,572,517	14,043	-	-	2,586,560	(433,249)	2,153,311
399	EASTON BLDG ARC	4,078	145	-	-	4,223	(4,223)	-
399	GEN BLDG ARC	30,951	1,193	-	-	32,144	(32,144)	-
399	LEBANON BLDG ARC	4,185	149	-	-	4,334	(4,334)	-
399	READING SOUTH BLDG ARC	8,235	277	-	-	8,512	(8,512)	-
399	YORK BLDG ARC	2,851	101	-	-	2,952	(2,952)	-
	TOTAL GENERAL PLANT	$ 119,452,188	$ 7,458,513	$ (412,068)	$ -	$ 126,498,633	$ (30,270,230)	$ 96,228,403
	NUCLEAR PRODUCTION							
326	TMI#2 ARC	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TOTAL	$ 1,005,696,963	$ 59,273,879	$ (9,476,820)	$ -	$ 1,055,494,022	$ (304,192,719)	$ 751,301,304

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 4/30/15 to 4/30/16
Calculated Reserves

Acct No	Description	Balance 4/30/15	Budget Activity: Accruals	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 4/30/16	Adjustments	Adjusted Balance 4/30/16
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	INTANGIBLE PLANT							
303	Misc. Intangible Plant	$ 38,046,432	$ 6,397,672	$ -	$ -	$ 44,444,104	$ (7,444,387)	$ 36,999,717
303	Smart Meter Software	180,580	1,096,976	-	-	1,277,556	-	1,277,556
	TOTAL INTANGIBLE PLANT	$ 38,227,012	$ 7,494,648	$ -	$ -	$ 45,721,660	$ (7,444,387)	$ 38,277,273
	TRANSMISSION PLANT							
	TRANSMISSION PLANT							
350.12	Easements - Trans. Subs.	$ 108,319	$ 2,601	$ -	$ -	$ 110,920	$ (110,920)	$ -
350.22	Easements - Trans. Lines	14,566,157	401,402	-	-	14,967,559	(14,967,559)	-
352.1	Structures, Improvements	3,180,215	119,140	-	-	3,299,355	(3,299,355)	-
352.2	Clearing, Grading Of Land	14,893	5,605	-	-	20,498	(20,498)	-
353	Station Equipment	45,213,571	3,403,882	(1,770,617)	-	46,846,836	(46,846,836)	-
354	Towers And Fixtures	22,551,869	476,557	-	-	23,028,426	(23,028,426)	-
355	Poles And Fixtures	15,218,339	679,625	-	-	15,897,964	(15,897,964)	-
356.1	Overhd Conductr, Devices	20,979,020	1,278,667	(514,322)	-	21,743,366	(21,743,366)	-
356.2	Clearing, Grading of Land	3,561,762	217,500	-	-	3,779,262	(3,779,262)	-
358	Undergrnd Conductr,Devices	83,539	29,898	-	-	113,437	(113,437)	-
359	Roads And Trails	562,901	16,807	-	-	579,708	(579,708)	-
359.1	ARC Transmission	2,718	104	-	-	2,822	(2,822)	-
	TOTAL TRANSMISSION PLANT	$ 126,043,303	$ 6,631,788	$ (2,284,939)	$ -	$ 130,390,153	$ (130,390,153)	$ -
	DISTRIBUTION PLANT							
360.12	Easements - Dist. Subs.	$ 181,768	$ 8,989	$ -	$ -	$ 190,757	$ -	$ 190,757
360.22	Easements - Dist. Lines	13,740,757	416,315	-	-	14,157,072	-	14,157,072
361.1	Structures, Improvements	6,247,845	309,730	-	-	6,557,575	-	6,557,575
361.2	Clearing, Grading of Land	729,347	8,895	-	-	738,242	-	738,242
362	Station Equipment	58,968,382	3,354,550	(391,660)	-	61,931,272	-	61,931,272
364	Poles, Towers And Fixtures	68,961,103	4,675,581	-	-	73,636,684	-	73,636,684
365	Overhd Conductr, Devices	59,221,488	6,296,101	-	-	65,517,589	-	65,517,589
365.1	Clearing, Grading of Land	18,347,166	2,002,446	-	-	20,349,612	-	20,349,612
366	Underground Conduit	12,331,468	527,164	-	-	12,858,632	-	12,858,632
367	Undergrnd Conductr,Devices	72,203,108	5,791,557	-	-	77,994,665	-	77,994,665
368	Line Transformers	97,998,268	10,231,203	(5,371,510)	-	102,857,961	-	102,857,961
369	Services	18,112,003	1,620,313	-	-	19,732,316	-	19,732,316
369	Underground Conduit	44,415,793	2,195,631	-	-	46,611,424	-	46,611,424
370	Meters	13,873,924	2,798,691	-	-	16,672,615	(16,672,615)	-
370	Smart Meters Res	107,270	469,918	(1,016,643)	-	(439,454)	-	(439,454)
371	Inst. On Cust. Prem.	1,989,222	144,175	-	-	2,133,397	-	2,133,397
373.1	Street Light - Oh, Ug Lines	2,149,736	340,409	-	-	2,490,145	-	2,490,145
374	ARC Distribution	22,190	759	-	-	22,949	(22,949)	-
	TOTAL DISTRIBUTION PLANT	$ 489,600,838	$ 41,192,427	$ (6,779,812)	$ -	$ 524,013,453	$ (16,695,564)	$ 507,317,889
	GENERAL PLANT							
389.2	Easements	$ 16,016	$ 400	$ -	$ -	$ 16,416	$ (2,750)	$ 13,666
390.1	Structures, Improvements	41,775,165	2,142,975	(44)	-	43,918,096	(7,356,281)	36,561,815
390.2	Clearing, Grading of Land	8,121,433	438,813	-	-	8,560,246	(1,433,841)	7,126,405
390.3	Struct Imprv, Leasehold Imp	4,546	590	-	-	5,136	(860)	4,276
391.1	Office Furn., Mech. Equip.	15,331,662	685,188	-	-	16,016,850	(2,682,822)	13,334,028
391.15	Office Machines	6,304,833	0	-	-	6,304,833	(1,056,060)	5,248,773
391.2	Data Processing Equipment	3,493,767	1,990,974	-	-	3,804,810	(637,306)	3,167,504
391.25	Data Proc Smart Meters	342,157	1,580,258	(310,658)	-	1,611,757	-	1,611,757
391.25	Information System	(4,908)	(1,311)	-	-	(6,438)	(1,078)	(7,516)
392	Transportation Equipment	398,497	225,082	(101,366)	-	522,214	(87,471)	434,743
393	Stores Equipment	1,359,700	12,421	-	-	1,372,121	(229,830)	1,142,291
394	Tools, Shop, Garage Equip.	7,532,669	490,726	-	-	8,023,395	(1,343,919)	6,679,476
395	Laboratory Equipment	2,885,332	30	-	-	2,885,362	(483,298)	2,402,064
396	Power Operated Equipment	353,093	12,929	-	-	366,022	(61,309)	304,713
397	Communication Equipment	17,382,386	1,024,095	-	-	18,406,481	(9,755,435)	8,651,046
398	Misc. Equipment	2,397,415	47,593	-	-	2,445,008	(409,539)	2,035,469
399.1	ARC General Plant	50,147	1,865	-	-	52,012	(52,012)	-
	TOTAL GENERAL PLANT	$ 107,743,912	$ 8,652,628	$ (412,068)	$ -	$ 114,304,322	$ (25,593,811)	$ 88,710,511
	TOTAL	$ 761,615,066	$ 63,971,491	$ (9,476,819)	$ -	$ 814,429,587	$ (180,123,915)	$ 634,305,673

METROPOLITAN EDISON COMPANY

Original Cost of Plant, Reserves and Accruals by Functions for Future Test Year Ending 3/31/2015

FILING REQUIREMENT V-A-1:

"Provide schedules supporting claimed amounts for Electric Plant in Service by function and by account if available."

FILING REQUIREMENT V-A-2:

"Provide a comparison of calculated depreciation reserve versus book reserve at the end of the test year. Provide this comparison by functional group and by account if available."

FILING REQUIREMENT V-B-1:

"Provide a comparison of calculated depreciation accruals versus book accruals by function and by account if available."

FILING REQUIREMENT V-D-1:

"Provide the surviving original cost plant at the appropriated test year date or dates by account and functional property group and include claimed depreciation reserves. Provide annual depreciation accruals where appropriate. These calculations should be provided for plant in service as well as other categories of plant, including but not limited to, contributions in aid of construction, customers' advances for construction and anticipated retirements associated with construction work in progress claims, if applicable."

RESPONSE:

Met-Ed Exhibit RAD-47 Attachment A satisfies the filing requirements cited above. The accruals shown on Met-Ed Exhibit RAD-47 Attachment A are claimed remaining life accruals for booking.

Met-Ed Exhibit RAD-47 Attachment B provides original cost activity at detail account levels for plant and reserves, updating this information from 3/31/14 through 3/31/15, the future test year-end. Additionally, this exhibit shows the affected balances after net adjustments made for rate case purposes, and the affected balances after net adjustments. This information is in support of Met-Ed Exhibit RAD-47 Attachment A as follows:

Pages 1-2 Company claim basis for Electric Plant in Service reflecting projected plant at 3/31/15 and net adjustments thereto.

Pages 3-4 Company claim basis of book reserves for Electric Plant in Service at 3/31/15 and net adjustments thereto.

Pages 5 Informational calculated reserves at 3/31/15 for Electric Plant in Service and net adjustments thereto.

Metropolitan Edison Company
Accrual Expense Computation after Adjustments
At Future Year from April 2014 to March 2015
($000)

Line No.	Description	Adjusted Plant Balances			Book Depreciation Reserve	Depreciation Reserve Ratio	Net Uncovered Book Plant	Accrual Average Remaining Life Basis		Calculated Reserve	Book Reserve	Difference	Difference as a % of Calculated Reserve
		Non Depreciable	Depreciable	Total				Amount	Effective Rate				
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Transmission	0	0	0	0	0.00%	0	0	0.00%	0	0	0	0.00%
2	Distribution	3,205	1,981,543	1,984,747	588,627	29.66%	1,396,120	37,020	1.87%	472,584	588,627	(116,043)	-24.55%
3	General Plant	2,673	147,950	150,623	90,041	59.78%	60,582	5,368	3.63%	81,503	90,041	(8,538)	-10.48%
4	Subtotal	5,878	2,129,492	2,135,370	678,668	31.78%	1,456,702	42,388	1.99%	554,087	678,668	(124,581)	-22.48%
5	Intangible Plant	289	36,794	37,083	27,385	73.85%	9,697	4,763	12.94%	31,428	27,385	4,043	12.86%
6	Total	6,166	2,166,286	2,172,453	706,053	32.50%	1,466,400	47,150	2.18%	585,515	706,053	(120,538)	-20.59%

Exhibit Reference									
	RAD-47 Attachment B P 1-2	RAD-47 Attachment B P 1-2	RAD-47 Attachment B P 1-2	RAD-47 Attachment B P 3-4		RAD-53 Attachment A P 1-2		RAD-47 Attachment B P 5-6	RAD-47 Attachment B P 3-4

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/14 to 3/31/15
Plant-In-Service

Acct No	Description	Balance 3/31/14	Budget Activity: Additions	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 3/31/15	Adjustments	Adjusted Balance 3/31/15
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	NONDEPRECIABLE PLANT							
	Intangible Plant							
301	Organization	$ 123,507	$ -	$ -	$ -	$ 123,507	$ -	$ 123,507
302	Franchise And Consents	165,169	-	-	-	165,169	-	165,169
	Total Intangible Plant	$ 288,676	$ -	$ -	$ -	$ 288,676	$ -	$ 288,676
	Land							
350.11	Transmission Substations	$ 1,384,344	$ -	$ -	$ -	$ 1,384,344	$ (1,384,344)	$ -
350.21	Transmission Lines	2,045,027	-	-	-	2,045,027	(2,045,027)	-
360.11	Distribution Substations.	2,777,235	-	-	-	2,777,235	-	2,777,235
360.21	Distribution Lines	427,642	-	-	-	427,642	-	427,642
389.1	General	2,672,808	-	-	-	2,672,808	-	2,672,808
	Total Land	$ 9,307,056	$ -	$ -	$ -	$ 9,307,056	$ (3,429,372)	$ 5,877,684
	TOTAL NON-DEPRECIABLE PLANT	$ 9,595,732	$ -	$ -	$ -	$ 9,595,732	$ (3,429,372)	$ 6,166,360
	INTANGIBLE PLANT							
303	Misc. Intangible Plant	$ 38,675,265	$ 2,927,401	$ -	$ -	$ 41,602,665	$ (6,968,446)	$ 34,634,219
303	Smart Meter Software	-	2,159,907	-	-	2,159,907	-	2,159,907
	TOTAL INTANGIBLE PLANT	$ 38,675,265	$ 5,087,308	$ -	$ -	$ 43,762,573	$ (6,968,446)	$ 36,794,126
	NUCLEAR PRODUCTION							
	Nuclear Production							
326	Asset Retirement Costs Nuclear	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TOTAL NUCLEAR PRODUCTION	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TRANSMISSION PLANT							
	TRANSMISSION PLANT							
350.12	Easements - Trans. Subs.	$ 173,374	$ -	$ -	$ -	$ 173,374	$ (173,374)	$ -
350.22	Easements - Trans. Lines	26,760,119	-	-	-	26,760,119	(26,760,119)	-
352.1	Structures, Improvements	6,475,002	-	-	-	6,475,002	(6,475,002)	-
352.2	Clearing, Grading Of Land	304,599	-	-	-	304,599	(304,599)	-
353	Station Equipment	183,422,634	12,419,729	(1,241,973)	-	194,600,390	(194,600,390)	-
354	Towers And Fixtures	41,082,524	-	-	-	41,082,524	(41,082,524)	-
355	Poles And Fixtures	46,549,680	-	-	-	46,549,680	(46,549,680)	-
356.1	Overhd Conductr, Devices	69,632,543	27,306,538	(2,730,654)	-	94,208,427	(94,208,427)	-
356.2	Clearing, Grading of Land	17,682,895	-	-	-	17,682,895	(17,682,895)	-
358	Undergrnd Conductr,Devices	1,191,163	-	-	-	1,191,163	(1,191,163)	-
359	Roads And Trails	746,971	-	-	-	746,971	(746,971)	-
359.1	ARC Transmission	4,666	-	-	-	4,666	(4,666)	-
	TOTAL TRANSMISSION PLANT	$ 394,026,169	$ 39,726,267	$ (3,972,627)	$ -	$ 429,779,809	$ (429,779,809)	$ -
	DISTRIBUTION PLANT							
360.12	Easements - Dist. Subs.	$ 611,470	$ -	$ -	$ -	$ 611,470	$ -	$ 611,470
360.22	Easements - Dist. Lines	28,320,720	-	-	-	28,320,720	-	28,320,720
361.1	Structures, Improvements	12,746,076	-	-	-	12,746,076	-	12,746,076
361.2	Clearing, Grading of Land	366,045	-	-	-	366,045	-	366,045
362	Station Equipment	203,494,152	10,531,662	(1,053,166)	-	212,972,648	-	212,972,648
364	Poles, Towers And Fixtures	354,210,686	-	-	-	354,210,686	-	354,210,686
365	Overhd Conductr, Devices	368,193,014	-	-	-	368,193,014	-	368,193,014
365.1	Clearing, Grading of Land	131,739,866	-	-	-	131,739,866	-	131,739,866
366	Underground Conduit	30,296,760	-	-	-	30,296,760	-	30,296,760
367	Undergrnd Conductr,Devices	203,212,529	-	-	-	203,212,529	-	203,212,529
368	Line Transformers	392,737,933	63,955,159	(6,395,516)	-	450,297,576	-	450,297,576
369	Services OH	71,066,339	-	-	-	71,066,339	-	71,066,339
369	Unground Services	98,458,792	-	-	-	98,458,792	-	98,458,792
370	Meters	66,794,533	-	-	-	66,794,533	(66,794,533)	0
370	Smart Meters Res	1,554,367	763,326	(76,333)	-	2,241,360	-	2,241,360
371	Inst. On Cust. Prem.	4,519,593	-	-	-	4,519,593	-	4,519,593
373.1	Street Light - Oh, Ug Lines	12,289,135	-	-	-	12,289,135	-	12,289,135
374	ARC Distribution	37,210	-	-	-	37,210	(37,210)	0
	TOTAL DISTRIBUTION PLANT	$ 1,980,649,220	$ 75,250,147	$ (7,525,015)	$ -	$ 2,048,374,353	$ (66,831,743)	$ 1,981,542,609

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/14 to 3/31/15
Plant-In-Service

Acct No	Description	Balance 3/31/14	Budget Activity			Balance 3/31/15	Adjustments	Adjusted Balance 3/31/15
			Additions	Retirements	Transfers/ Adjustments			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	GENERAL PLANT							
389.2	Easements	$ 18,078	$ -	$ -	$ -	$ 18,078	$ (3,028)	$ 15,050
390.1	Structures, Improvements	85,738,057	1,922,342	(192,234)	-	87,468,165	(14,650,918)	72,817,247
390.2	Clearing, Grading of Land	12,466,282	-	-	-	12,466,282	(2,088,102)	10,378,180
390.3	Struct Imprv, Leasehold Imp	16,754	-	-	-	16,754	(2,806)	13,948
391.1	Office Furn., Mech. Equip.	16,630,775	-	-	-	16,630,775	(2,785,655)	13,845,120
391.15	Office Machines	5,920,633	-	-	-	5,920,633	(991,706)	4,928,927
391.2	Data Processing Equipment	4,626,945	-	-	-	4,626,945	(775,013)	3,851,932
391.25	Data Proc Smart Meters	902,575	6,059,138	(605,914)	-	6,355,799	-	6,355,799
391.25	Information System	(11,738)	-	-	-	(11,738)	1,966	(9,772)
392	Transportation Equipment	1,066,971	3,513,906	(351,391)	-	4,229,487	(708,439)	3,521,048
393	Stores Equipment	1,411,422	-	-	-	1,411,422	(236,413)	1,175,009
394	Tools, Shop, Garage Equip.	11,711,828	-	-	-	11,711,828	(1,961,731)	9,750,097
395	Laboratory Equipment	3,047,684	-	-	-	3,047,684	(510,487)	2,537,197
396	Power Operated Equipment	751,658	-	-	-	751,658	(125,903)	625,755
397	Communication Equipment	34,023,088	-	-	-	34,023,088	(18,032,237)	15,990,851
398	Misc. Equipment	2,586,560	-	-	-	2,586,560	(433,249)	2,153,311
399.1	ARC General Plant	105,951	-	-	-	105,951	(105,951)	0
	TOTAL GENERAL PLANT	$ 181,013,523	$ 11,495,386	$ (1,149,539)	$ -	$ 191,359,370	$ (43,409,672)	$ 147,949,698
	TOTAL	$ 2,699,281,063	$ 131,559,108	$ (12,647,180)	$ -	$ 2,818,192,991	$ (645,740,197)	$ 2,172,452,794

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/14 to 3/31/15
Book Reserves

Acct No	Description	Balance 3/31/14	Budget Activity: Accruals	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 3/31/15	Adjustments	Adjusted Balance 3/31/15
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	INTANGIBLE PLANT							
303	Software	$ 30,402,371	$ 2,366,058	$ -	$ -	$ 32,768,429	$ (5,488,712)	$ 27,279,717
303	Smart Meters	-	105,622	-	-	105,622	-	105,622
	TOTAL INTANGIBLE PLANT	$ 30,402,371	$ 2,471,680	$ -	$ -	$ 32,874,051	$ (5,488,712)	$ 27,385,339
	TRANSMISSION PLANT							
350.12	Tran Sub Easement	$ 104,764	$ 2,602	$ -	$ -	$ 107,366	$ (107,366)	$ -
350.21	Tran Line Land	7,848	-	-	-	7,848	(7,848)	-
350.22	Tran Line Easement	11,437,774	401,540	-	-	11,839,314	(11,839,314)	-
352	Struct PCA Dist	66,104	2,030	-	-	68,134	(68,134)	-
352	Structures/improve	2,657,861	122,101	-	-	2,779,962	(2,779,962)	-
353	Station Eq PCA Dist	2,078,624	137,587	-	-	2,216,211	(2,216,211)	-
353	Station equipment	54,044,683	3,026,853	(1,241,973)	-	55,829,563	(55,829,563)	-
354	Towers & Fixtures	26,703,276	486,478	-	-	27,189,754	(27,189,754)	-
354	Towers PCA Dist	33,308	453	-	-	33,761	(33,761)	-
355	Poles & Fixtures	17,594,774	656,833	-	-	18,251,607	(18,251,607)	-
355	Poles PCA Dist	385,672	8,518	-	-	394,190	(394,190)	-
356	OH Cond PCA Dist	288,851	6,740	-	-	295,591	(295,591)	-
356	Overhead Conductor	29,183,652	1,125,540	(2,730,654)	-	27,578,538	(27,578,538)	-
356.1	0 Clearing & R/W	2,996,754	90,356	-	-	3,087,110	(3,087,110)	-
356.1	0 R/W PCA Dist	623,504	146,557	-	-	770,061	(770,061)	-
356.2	0 Veg Clrng-FERC exp	-	-	-	-	-	-	-
358	UG Cond PCA Dist	257	48	-	-	305	(305)	-
358	Undergound Conductor	68,886	29,198	-	-	98,084	(98,084)	-
359	Roads & Trails	508,950	16,548	-	-	525,498	(525,498)	-
359	Roads PCA Dist	7,708	268	-	-	7,976	(7,976)	-
359.1	TXM SUB ARC	2,614	104	-	-	2,718	(2,718)	-
	TOTAL TRANSMISSION PLANT	$ 148,795,864	$ 6,260,354	$ (3,972,627)	$ -	$ 151,083,591	$ (151,083,591)	$ -
	DISTRIBUTION PLANT							
360.12	Dist Sub Easement	$ 172,767	$ 9,004	$ -	$ -	$ 181,771	$ -	$ 181,771
360.22	Dist Line Easement	13,966,846	417,008	-	-	14,383,854	-	14,383,854
361	Structure/Improve	5,912,467	313,866	-	-	6,226,333	-	6,226,333
361.2	Grading Clearing	14,621	9,014	-	-	23,635	-	23,635
362	Station equipment	71,463,977	3,228,717	(1,053,166)	-	73,639,528	-	73,639,528
364	Poles towers fix	104,110,956	4,769,507	-	-	108,880,463	-	108,880,463
365	Overhead conductor	74,758,065	6,143,661	-	-	80,901,726	-	80,901,726
365.1	Clearing & R/W	16,929,114	2,011,562	-	-	18,940,676	-	18,940,676
366	Underground conduit	10,848,259	529,030	-	-	11,377,289	-	11,377,289
367	Undergrd conductor	66,220,681	5,794,026	-	-	72,014,707	-	72,014,707
368	Line Transformers	124,984,867	9,124,863	(6,395,516)	-	127,714,214	-	127,714,214
369	Services OH	18,079,480	1,638,032	-	-	19,717,512	-	19,717,512
369	Unground Services	46,515,808	2,219,858	-	-	48,735,666	-	48,735,666
370	Meters	12,084,587	2,719,479	(76,333)	-	14,727,733	(14,727,733)	-
370	Smart Meters Res	49,520	109,350	-	-	158,870	-	158,870
371	Inst on cust prem	1,854,566	123,663	-	-	1,978,229	-	1,978,229
371	Meter Socket dvc 125	177	8	-	-	185	-	185
371	Meter Socket dvc 126	177	8	-	-	185	-	185
371	Meter Socket dvc 127	361	15	-	-	376	-	376
371	Meter Socket dvc 1PH	301,334	13,242	-	-	314,576	-	314,576
371	Meter Socket dvc 3PH	258	11	-	-	269	-	269
371	Surge Suppression 2	240,849	-	-	-	240,849	-	240,849
371	Surge Suppression 4	35,859	-	-	-	35,859	-	35,859
373	Street Lighting	2,839,229	321,122	-	-	3,160,351	-	3,160,351
374	DIST SUB ARC	21,431	759	-	-	22,190	(22,190)	-
	TOTAL DISTRIBUTION PLANT	$ 571,406,256	$ 39,495,805	$ (7,525,015)	$ -	$ 603,377,046	$ (14,749,923)	$ 588,627,123

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/14 to 3/31/15
Book Reserves

Acct No	Description	Balance 3/31/14	Budget Activity			Balance 3/31/15	Adjustments	Adjusted Balance 3/31/15
			Accruals	Retirements	Transfers/ Adjustments			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	GENERAL PLANT							
389.2	Land Rights	$ 15,207	$ 407	$ -	$ -	$ 15,614	$ (2,615)	$ 12,998
390.1	Easton Serv Center	4,009,499	312,519	-	-	4,322,018	(723,938)	3,598,080
390.1	Lebanon Serv Ctr	3,118,784	187,671	-	-	3,306,455	(553,831)	2,752,624
390.1	South Bldg Reading	25,342,274	1,115,101	(192,234)	-	26,265,141	(4,399,411)	21,865,730
390.1	Structures	7,829,637	409,507	-	-	8,239,144	(1,380,057)	6,859,087
390.1	York Serv Center	3,983,411	209,705	-	-	4,193,116	(702,347)	3,490,769
390.2	Corp Hqtrs Reading	1,714,197	90,647	-	-	1,804,844	(302,311)	1,502,533
390.2	Easton Ser Ctr	873,250	116,782	-	-	990,032	(165,830)	824,202
390.2	Land/Yard Improvem	2,836,743	169,861	-	-	3,006,604	(503,606)	2,502,997
390.2	Lebanon Ser Ctr	793,528	23,374	-	-	816,902	(136,831)	680,071
390.2	York Ser Ctr	1,142,997	46,769	-	-	1,189,766	(199,286)	990,481
390.3	Transfered LH	4,293	838	-	-	5,131	(859)	4,272
391.1	Office Furniture	14,646,201	742,483	-	-	15,388,684	(2,577,605)	12,811,079
391.15	Office Machines	5,920,633	-	-	-	5,920,633	(991,706)	4,928,927
391.2	Personal Computers	2,240,191	788,606	-	-	3,028,797	(507,324)	2,521,474
391.25	Data Proc Smart Me	86,074	741,854	(605,914)	-	222,014	-	222,014
391.25	Information Sys	(2,944)	(4,172)	-	-	(7,116)	1,192	(5,924)
392	Transportation equip	79,504	29,749	-	-	109,253	(18,300)	90,953
392.4	Pole Trailers	460,815	25,554	-	-	486,369	(81,467)	404,902
392.5	Van Trailers	79,071	717	-	-	79,788	(13,364)	66,423
393	Stores Equipment	1,404,210	7,211	-	-	1,411,421	(236,413)	1,175,008
394	Tools shop garage	6,684,476	514,703	-	-	7,199,179	(1,205,863)	5,993,317
395	Laboratory equip	3,047,684	-	-	-	3,047,684	(510,487)	2,537,197
396	Power operated equip	613,115	4,230	-	-	617,345	(103,405)	513,940
397	Communication Equipt	23,913,531	1,033,712	(351,391)	-	24,595,852	(13,035,802)	11,560,051
398	Miscellaneous equipt	2,505,460	61,899	-	-	2,567,359	(430,033)	2,137,326
399	EASTON BLDG ARC	3,921	145	-	-	4,066	(4,066)	-
399	GEN BLDG ARC	29,659	1,193	-	-	30,852	(30,852)	-
399	LEBANON BLDG ARC	4,024	149	-	-	4,173	(4,173)	-
399	READING SOUTH BLDG ARC	7,935	277	-	-	8,212	(8,212)	-
399	YORK BLDG ARC	2,742	101	-	-	2,843	(2,843)	-
	TOTAL GENERAL PLANT	$ 113,390,122	$ 6,631,592	$ (1,149,539)	$ -	$ 118,872,175	$ (28,831,646)	$ 90,040,529
	NUCLEAR PRODUCTION							
326	TMI#2 ARC	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TOTAL	$ 959,315,767	$ 54,859,431	$ (12,647,181)	$ -	$ 1,001,528,017	$ (295,475,026)	$ 706,052,991

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/14 to 3/31/15
Calculated Reserves

Acct No	Description	Balance 3/31/14	Budget Activity: Accruals	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 3/31/15	Adjustments	Adjusted Balance 3/31/15
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	INTANGIBLE PLANT							
303	Misc. Intangible Plant	$ 32,404,302	$ 5,161,871	$ -	$ -	$ 37,566,173	$ (6,292,334)	$ 31,273,839
303	Smart Meter Software	-	154,325	-	-	154,325	-	154,325
	TOTAL INTANGIBLE PLANT	$ 32,404,302	$ 5,316,196	$ -	$ -	$ 37,720,498	$ (6,292,334)	$ 31,428,164
	TRANSMISSION PLANT							
	TRANSMISSION PLANT							
350.12	Easements - Trans. Subs.	$ 105,501	$ 2,601	$ -	$ -	$ 108,102	$ (108,102)	$ -
350.22	Easements - Trans. Lines	14,131,305	401,402	-	-	14,532,707	(14,532,707)	0
352.1	Structures, Improvements	3,051,201	119,140	-	-	3,170,341	(3,170,341)	0
352.2	Clearing, Grading Of Land	8,823	5,605	-	-	14,428	(14,428)	0
353	Station Equipment	43,010,923	3,175,393	(1,241,973)	-	44,944,343	(44,944,343)	0
354	Towers And Fixtures	22,034,572	476,557	-	-	22,511,129	(22,511,129)	0
355	Poles And Fixtures	14,483,242	679,625	-	-	15,162,867	(15,162,867)	0
356.1	Overhd Conductr, Devices	22,526,864	1,081,350	(2,730,654)	-	20,877,560	(20,877,560)	0
356.2	Clearing, Grading of Land	3,326,137	217,500	-	-	3,543,637	(3,543,637)	0
358	Undergrnd Conductr,Devices	51,199	29,898	-	-	81,097	(81,097)	0
359	Roads And Trails	544,693	16,807	-	-	561,500	(561,500)	0
359.1	ARC Transmission	2,614	104	-	-	2,718	(2,718)	0
	TOTAL TRANSMISSION PLANT	$ 123,277,074	$ 6,205,982	$ (3,972,627)	$ -	$ 125,510,429	$(125,510,429)	$ -
	DISTRIBUTION PLANT							
360.12	Easements - Dist. Subs.	$ 172,030	$ 8,989	$ -	$ -	$ 181,019	$ -	$ 181,019
360.22	Easements - Dist. Lines	13,289,749	416,315	-	-	13,706,064	-	13,706,064
361.1	Structures, Improvements	5,911,986	309,730	-	-	6,221,716	-	6,221,716
361.2	Clearing, Grading of Land	719,702	8,895	-	-	728,597	-	728,597
362	Station Equipment	56,499,600	3,248,441	(1,053,166)	-	58,694,875	-	58,694,875
364	Poles, Towers And Fixtures	63,887,035	4,675,581	-	-	68,562,616	-	68,562,616
365	Overhd Conductr, Devices	52,412,985	6,296,101	-	-	58,709,086	-	58,709,086
365.1	Clearing, Grading of Land	16,176,752	2,002,446	-	-	18,179,198	-	18,179,198
366	Underground Conduit	11,760,121	527,164	-	-	12,287,285	-	12,287,285
367	Undergrnd Conductr,Devices	65,928,921	5,791,557	-	-	71,720,478	-	71,720,478
368	Line Transformers	94,567,042	9,020,480	(6,395,516)	-	97,192,006	-	97,192,006
369	Services	16,355,480	1,620,313	-	-	17,975,793	-	17,975,793
369	Underground Conduit	42,035,552	2,195,631	-	-	44,231,183	-	44,231,183
370	Meters	10,848,688	2,798,691	-	-	13,647,379	(13,647,379)	0
370	Smart Meters Res	43,921	126,587	(76,333)	-	94,175	-	94,175
371	Inst. On Cust. Prem.	1,832,882	144,175	-	-	1,977,057	-	1,977,057
373.1	Street Light - Oh, Ug Lines	1,782,598	340,409	-	-	2,123,007	-	2,123,007
374	ARC Distribution	21,431	759	-	-	22,190	(22,190)	0
	TOTAL DISTRIBUTION PLANT	$ 454,246,475	$39,532,264	$ (7,525,015)	$ -	$ 486,253,724	$ (13,669,569)	$ 472,584,156
	GENERAL PLANT							
389.2	Easements	$ 15,582	$ 400	$ -	$ -	$ 15,982	$ (2,677)	$ 13,305
390.1	Structures, Improvements	39,644,446	2,121,776	(192,234)	-	41,573,988	(6,963,643)	34,610,345
390.2	Clearing, Grading of Land	7,653,948	438,813	-	-	8,092,761	(1,355,537)	6,737,224
390.3	Struct Imprv, Leasehold Imp	3,917	590	-	-	4,507	(755)	3,752
391.1	Office Furn., Mech. Equip.	14,563,459	685,188	-	-	15,248,647	(2,554,148)	12,694,499
391.15	Office Machines	6,275,279	-	-	-	6,275,279	(1,051,109)	5,224,170
391.2	Data Processing Equipment	1,479,697	1,990,974	-	-	1,790,740	(299,949)	1,490,791
391.25	Data Proc Smart Meters	115,075	725,837	(605,914)	-	234,998	-	234,998
391.25	Information System	(3,538)	(1,311)	-	-	(5,068)	849	(4,219)
392	Transportation Equipment	602,648	126,056	(351,391)	-	377,313	(63,200)	314,113
393	Stores Equipment	1,344,727	12,421	-	-	1,357,148	(227,322)	1,129,826
394	Tools, Shop, Garage Equip.	6,999,097	490,726	-	-	7,489,823	(1,254,545)	6,235,278
395	Laboratory Equipment	2,885,251	30	-	-	2,885,281	(483,285)	2,401,997
396	Power Operated Equipment	339,813	12,929	-	-	352,742	(59,084)	293,658
397	Communication Equipment	16,277,203	1,024,095	-	-	17,301,298	(9,169,688)	8,131,610
398	Misc. Equipment	2,344,670	47,593	-	-	2,392,263	(400,704)	1,991,559
399.1	ARC General Plant	48,282	1,865	-	-	50,147	(50,147)	0
	TOTAL GENERAL PLANT	$ 100,589,557	$ 7,677,982	$ (1,149,539)	$ -	$ 105,437,851	$ (23,934,946)	$ 81,502,905
	TOTAL	$ 710,517,409	$58,732,424	$ (12,647,180)	$ -	$ 754,922,503	$(169,407,278)	$ 585,515,225

METROPOLITAN EDISON COMPANY

Original Cost of Plant, Reserves and Accruals by Functions for Historical Test Year Ended 3/31/2014

FILING REQUIREMENT V-A-1:

"Provide schedules supporting claimed amounts for Electric Plant in Service by function and by account if available."

FILING REQUIREMENT V-A-2:

"Provide a comparison of calculated depreciation reserve versus book reserve at the end of the test year. Provide this comparison by functional group and by account if available."

FILING REQUIREMENT V-B-1:

"Provide a comparison of calculated depreciation accruals versus book accruals by function and by account if available."

FILING REQUIREMENT V-D-1:

"Provide the surviving original cost plant at the appropriated test year date or dates by account and functional property group and include claimed depreciation reserves. Provide annual depreciation accruals where appropriate. These calculations should be provided for plant in service as well as other categories of plant, including but not limited to, contributions in aid of construction, customers' advances for construction and anticipated retirements associated with construction work in progress claims, if applicable."

RESPONSE:

Met-Ed Exhibit RAD-48 Attachment A satisfies the filing requirements cited above. The accruals shown on Met-Ed Exhibit RAD-48 Attachment A are claimed remaining life accruals for booking.

Met-Ed Exhibit RAD-48 Attachment B provides original cost activity at detail account levels for plant and reserves, updating this information from 3/31/13 through 3/31/14, the historical test year-end. Additionally, this exhibit shows the affected balances after net adjustments made for rate case purposes, and the affected balances after net adjustments. This information is in support of Met-Ed Exhibit RAD-48 Attachment A as follows:

Pages 1-2 Company claim basis for Electric Plant in Service reflecting projected plant at 3/31/14 and net adjustments thereto.

Pages 3-4 Company claim basis of book reserves for Electric Plant in Service at 3/31/14 and net adjustments thereto.

Pages 5 Informational calculated reserves at 3/31/14 for Electric Plant in Service and net adjustments thereto.

Metropolitan Edison Company
Accrual Expense Computation after Adjustments
At Future Year from April 2013 to March 2014
($000)

Met-Ed Exhibit RAD-48
Witness: R. A. D'Angelo
Attachment A
Page 1 of 1

Line No.	Description	Adjusted Plant Balances			Book Depreciation Reserve	Depreciation Reserve Ratio	Net Uncovered Book Plant	Accrual Average Remaining Life Basis		Calculated Reserve	Book Reserve	Difference	Difference as a % of Calculated Reserve
		Non Depreciable	Depreciable	Total				Amount	Effective Rate				
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Transmission	-	-	-	-	0.00%	-	-	0.00%	-	-	-	0.00%
2	Distribution	3,205	1,913,817	1,917,022	559,300	29.18%	1,357,722	35,549	1.86%	443,376,357	559,300	442,817,056	99.87%
3	General Plant	2,673	138,423	141,096	85,703	60.74%	55,393	4,812	3.48%	77,819,400	85,703	77,733,698	99.89%
4	Subtotal	5,878	2,052,241	2,058,119	645,003	31.34%	1,413,115	40,361	1.97%	521,195,757	645,003	520,550,754	99.88%
5	Intangible Plant	289	32,197	32,486	25,310	77.91%	7,176	4,459	13.85%	26,976,581	25,310	26,951,271	99.91%
6	Total	6,166	2,084,438	2,090,604	670,313	32.06%	1,420,291	44,820	2.15%	548,172,338	670,313	547,502,025	99.88%

Exhibit Reference									
	RAD-48 Attachment B P 1-2	RAD-48 Attachment B P 1-2	RAD-48 Attachment B P 1-2	RAD-48 Attachment B P 3-4		RAD-53 Attachment A P 1-2		RAD-48 Attachment B P 5-6	RAD-48 Attachment B P 3-4

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/13 to 3/31/14
Plant-In-Service

Acct No	Description	Balance 3/31/13	Actual Activity: Additions	Actual Activity: Retirements	Actual Activity: Transfers/ Adjustments	Balance 3/31/14	Adjustments	Adjusted Balance 3/31/14
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	NONDEPRECIABLE PLANT							
	Intangible Plant							
301	Organization	$ 123,507	$ -	$ -	$ -	$ 123,507	$ -	$ 123,507
302	Franchise And Consents	165,169	-	-	-	165,169	-	165,169
	Total Intangible Plant	$ 288,676	$ -	$ -	$ -	$ 288,676	$ -	$ 288,676
	Land							
350.11	Transmission Substations	$ 1,384,344	$ -	$ -	$ -	$ 1,384,344	$ (1,384,344)	$ -
350.21	Transmission Lines	2,045,027	-	-	-	2,045,027	(2,045,027)	-
360.11	Distribution Substations.	2,777,235	-	-	-	2,777,235	-	2,777,235
360.21	Distribution Lines	303,117	124,525	-	-	427,642	-	427,642
389.1	General	1,567,850	1,104,958	-	-	2,672,808	-	2,672,808
	Total Land	$ 8,077,573	$ 1,229,483	$ -	$ -	$ 9,307,056	$ (3,429,372)	$ 5,877,684
	TOTAL NON-DEPRECIABLE PLANT	$ 8,366,250	$ 1,229,483	$ -	$ -	$ 9,595,732	$ (3,429,372)	$ 6,166,360
	INTANGIBLE PLANT							
303	Misc. Intangible Plant	$ 38,319,710	$ 355,554	$ -	$ -	$ 38,675,265	$ (6,478,107)	$ 32,197,158
303	Smart Meter Software	-	-	-	-	-	-	-
	TOTAL INTANGIBLE PLANT	$ 38,319,710	$ 355,554	$ -	$ -	$ 38,675,265	$ (6,478,107)	$ 32,197,158
	NUCLEAR PRODUCTION							
	Nuclear Production							
326	Asset Retirement Costs Nuclear	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TOTAL NUCLEAR PRODUCTION	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TRANSMISSION PLANT							
	TRANSMISSION PLANT							
350.12	Easements - Trans. Subs.	$ 409,521	$ (236,147)	$ -	$ -	$ 173,374	$ (173,374)	$ -
350.22	Easements - Trans. Lines	26,760,119	-	-	-	26,760,119	(26,760,119)	-
352.1	Structures, Improvements	5,744,218	730,784	-	-	6,475,002	(6,475,002)	-
352.2	Clearing, Grading Of Land	1,704,204	(355,113)	-	(1,044,491)	304,599	(304,599)	-
353	Station Equipment	166,315,953	17,922,447	(1,022,430)	206,664	183,422,634	(183,422,634)	-
354	Towers And Fixtures	41,961,853	(835,615)	(43,714)	-	41,082,524	(41,082,524)	-
355	Poles And Fixtures	43,899,431	3,155,306	(505,057)	-	46,549,680	(46,549,680)	-
356.1	Overhd Conductr, Devices	64,881,925	5,301,147	(550,529)	-	69,632,543	(69,632,543)	-
356.2	Clearing, Grading of Land	13,185,234	4,760,033	-	(262,373)	17,682,895	(17,682,895)	-
358	Undergrnd Conductr,Devices	1,023,580	167,583	-	-	1,191,163	(1,191,163)	-
359	Roads And Trails	746,971	-	-	-	746,971	(746,971)	-
359.1	ARC Transmission	4,666	-	-	-	4,666	(4,666)	-
	TOTAL TRANSMISSION PLANT	$ 366,637,674	$ 30,610,425	$ (2,121,730)	$ (1,100,200)	$ 394,026,169	$ (394,026,169)	$ -
	DISTRIBUTION PLANT							
360.12	Easements - Dist. Subs.	$ 375,323	$ 236,147	$ -	$ -	$ 611,470	$ -	$ 611,470
360.22	Easements - Dist. Lines	28,320,720	-	-	-	28,320,720	-	28,320,720
361.1	Structures, Improvements	12,675,915	72,483	(2,322)	-	12,746,076	-	12,746,076
361.2	Clearing, Grading of Land	130,317	235,728	-	-	366,045	-	366,045
362	Station Equipment	198,607,004	5,516,100	(1,401,555)	772,603	203,494,152	-	203,494,152
364	Poles, Towers And Fixtures	382,640,929	(26,431,291)	(1,998,952)	-	354,210,686	-	354,210,686
365	Overhd Conductr, Devices	325,681,473	48,060,041	(5,548,499)	-	368,193,014	-	368,193,014
365.1	Clearing, Grading of Land	122,275,939	9,812,851	-	(348,923)	131,739,866	-	131,739,866
366	Underground Conduit	30,228,744	75,426	(7,411)	-	30,296,760	-	30,296,760
367	Undergrnd Conductr,Devices	190,569,314	14,192,343	(1,549,128)	-	203,212,529	-	203,212,529
368	Line Transformers	388,639,778	8,031,488	(3,933,333)	-	392,737,933	-	392,737,933
369	Services OH	68,503,817	2,624,523	(62,001)	-	71,066,339	-	71,066,339
369	Unground Services	98,458,792	-	-	-	98,458,792	-	98,458,792
370	Meters	64,399,297	3,792,170	(1,453,354)	56,420	66,794,533	(66,794,533)	-
370	Smart Meters Res	-	1,616,822	(6,036)	(56,420)	1,554,367	-	1,554,367
371	Inst. On Cust. Prem.	4,413,800	127,572	(21,779)	-	4,519,593	-	4,519,593
373.1	Street Light - Oh, Ug Lines	11,516,382	1,364,349	(591,596)	-	12,289,135	-	12,289,135
374	ARC Distribution	37,210	-	-	-	37,210	(37,210)	0
	TOTAL DISTRIBUTION PLANT	$ 1,927,474,753	$ 69,326,752	$ (16,575,966)	$ 423,681	$ 1,980,649,220	$ (66,831,743)	$ 1,913,817,477

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/13 to 3/31/14
Plant-In-Service

Acct No	Description	Balance 3/31/13	Actual Activity: Additions	Actual Activity: Retirements	Actual Activity: Transfers/ Adjustments	Balance 3/31/14	Adjustments	Adjusted Balance 3/31/14
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	GENERAL PLANT							
389.2	Easements	$ 18,078	$ -	$ -	$ -	$ 18,078	$ (3,028)	$ 15,050
390.1	Structures, Improvements	85,320,181	601,479	(183,603)	-	85,738,057	(14,361,125)	71,376,932
390.2	Clearing, Grading of Land	12,466,282	-	-	-	12,466,282	(2,088,102)	10,378,180
390.3	Struct Imprv, Leasehold Imp	16,754	-	-	-	16,754	(2,806)	13,948
391.1	Office Furn., Mech. Equip.	17,100,332	51,987	(521,544)	-	16,630,775	(2,785,655)	13,845,120
391.15	Office Machines	5,920,633	-	-	-	5,920,633	(991,706)	4,928,927
391.2	Data Processing Equipment	2,552,753	2,674,717	(460,109)	(140,416)	4,626,945	(775,013)	3,851,932
391.25	Data Proc Smart Meters	-	654,400	-	248,174	902,575	-	902,575
391.25	Information System	350	96,022	(351)	(107,758)	(11,738)	1,966	(9,772)
392	Transportation Equipment	1,219,015	(108,393)	-	(43,650)	1,066,971	(178,718)	888,253
393	Stores Equipment	1,428,705		(17,284)	-	1,411,422	(236,413)	1,175,009
394	Tools, Shop, Garage Equip.	10,252,799	1,774,515	(315,486)	-	11,711,828	(1,961,731)	9,750,097
395	Laboratory Equipment	3,130,477		(82,793)	-	3,047,684	(510,487)	2,537,197
396	Power Operated Equipment	642,814	108,844		-	751,658	(125,903)	625,755
397	Communication Equipment	35,658,936	432,337	(2,068,186)	-	34,023,088	(18,032,237)	15,990,851
398	Misc. Equipment	2,671,047	11,519	(96,006)	-	2,586,560	(433,249)	2,153,311
399.1	ARC General Plant	105,951	-	-	-	105,951	(105,951)	0
	TOTAL GENERAL PLANT	$ 178,505,106	$ 6,297,428	$ (3,745,361)	$ (43,650)	$ 181,013,522	$ (42,590,158)	$ 138,423,365
	TOTAL	$ 2,614,624,648	$ 107,819,642	$ (22,443,057)	$ (720,170)	$ 2,699,281,063	$ (608,676,703)	$ 2,090,604,360

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/13 to 3/31/14
Book Reserves

Acct No	Description	Balance 3/31/13	Actual Activity: Accruals	Actual Activity: Retirements	Actual Activity: Transfers/ Adjustments	Balance 3/31/14	Adjustments	Adjusted Balance 3/31/14
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	INTANGIBLE PLANT							
303	Software	$ 27,397,359	$ 3,005,012	$ -	$ -	$ 30,402,371	$ (5,092,397)	$ 25,309,974
303	Smart Meters					-	-	-
	TOTAL INTANGIBLE PLANT	$ 27,397,359	$ 3,005,012	$ -	$ -	$ 30,402,371	$ (5,092,397)	$ 25,309,974
	TRANSMISSION PLANT							
350.12	Tran Sub Easement	$ 101,129	$ 3,635	$ -	$ -	$ 104,764	$ (104,764)	$ -
350.21	Tran Line Land	7,848	(1,500)	-	1,500	7,848	(7,848)	-
350.22	Tran Line Easement	11,036,233	401,540	-	-	11,437,774	(11,437,774)	-
352	Struct PCA Dist	64,073	2,030	-	-	66,104	(66,104)	-
352	Structures/improve	2,601,010	123,758	-	(66,907)	2,657,861	(2,657,861)	-
353	Station Eq PCA Dist	1,957,015	137,550	(16,631)	690	2,078,624	(2,078,624)	-
353	Station equipment	52,321,305	2,778,769	(1,005,799)	(49,591)	54,044,683	(54,044,683)	-
354	Towers & Fixtures	26,258,318	488,672	(43,714)	-	26,703,276	(26,703,276)	-
354	Towers PCA Dist	32,855	453	-	-	33,308	(33,308)	-
355	Poles & Fixtures	17,453,861	645,971	(505,057)	-	17,594,774	(17,594,774)	-
355	Poles PCA Dist	377,154	8,518	-	-	385,672	(385,672)	-
356	OH Cond PCA Dist	282,111	6,740	-	-	288,851	(288,851)	-
356	Overhead Conductor	28,877,319	1,494,525	(550,529)	(637,663)	29,183,652	(29,183,652)	-
356.1	Clearing & R/W	3,013,311	116,179	-	(132,737)	2,996,754	(2,996,754)	-
356.1	R/W PCA Dist	309,208	90,180	-	224,116	623,504	(623,504)	-
356.2	Veg Clrng-FERC exp	-	-	-	-	-	-	-
358	UG Cond PCA Dist	209	48	-	-	257	(257)	-
358	Undergound Conductor	41,135	27,750	-	-	68,886	(68,886)	-
359	Roads & Trails	492,403	16,548	-	-	508,950	(508,950)	-
359	Roads PCA Dist	7,440	268	-	-	7,708	(7,708)	-
359.1	TXM SUB ARC	2,511	104	-	-	2,614	(2,614)	-
	TOTAL TRANSMISSION PLANT	$ 145,236,448	$ 6,341,738	$ (2,121,730)	$ (660,592)	$ 148,795,864	$ (148,795,864)	$ -
	DISTRIBUTION PLANT							
360.12	Dist Sub Easement	$ 164,777	$ 7,989	$ -	$ -	$ 172,767	$ -	$ 172,767
360.22	Dist Line Easement	13,549,839	417,008	-	-	13,966,846	-	13,966,846
361	Structure/Improve	5,601,618	313,171	(2,322)	-	5,912,467	-	5,912,467
361.2	Grading Clearing	9,260	5,361	-	-	14,621	-	14,621
362	Station equipment	69,591,323	3,952,890	(1,401,555)	(678,681)	71,463,977	-	71,463,977
364	Poles towers fix	101,435,336	4,674,572	(1,998,952)	-	104,110,956	-	104,110,956
365	Overhead conductor	74,288,389	7,207,288	(5,548,499)	(1,189,114)	74,758,065	-	74,758,065
365.1	Clearing & R/W	15,024,997	1,928,590	-	(24,472)	16,929,114	-	16,929,114
366	Underground conduit	10,326,967	528,703	(7,411)	-	10,848,259	-	10,848,259
367	Undergrd conductor	62,131,972	5,637,837	(1,549,128)	-	66,220,681	-	66,220,681
368	Line Transformers	120,583,394	8,795,800	(3,933,333)	(460,994)	124,984,867	-	124,984,867
369	Services OH	16,527,158	4,339,839	(62,001)	(2,725,516)	18,079,480	-	18,079,480
369	Unground Services	44,295,950	2,219,858	-	-	46,515,808	-	46,515,808
370	Meters	10,867,039	2,669,623	(1,453,354)	1,279	12,084,587	(12,084,587)	-
370	Smart Meters Res	-	56,836	(6,036)	(1,279)	49,520	-	49,520
371	Inst on cust prem	1,753,450	122,894	(21,779)	-	1,854,566	-	1,854,566
371	Meter Socket dvc 125	169	8	-	-	177	-	177
371	Meter Socket dvc 126	169	8	-	-	177	-	177
371	Meter Socket dvc 127	346	15	-	-	361	-	361
371	Meter Socket dvc 1PH	288,092	13,242	-	-	301,334	-	301,334
371	Meter Socket dvc 3PH	246	11	-	-	258	-	258
371	Surge Suppression 2	240,849	-	-	-	240,849	-	240,849
371	Surge Suppression 4	35,859	-	-	-	35,859	-	35,859
373	Street Lighting	3,112,557	(69,008)	(591,596)	387,276	2,839,229	-	2,839,229
374	DIST SUB ARC	20,672	759	-	-	21,431	(21,431)	-
	TOTAL DISTRIBUTION PLANT	$ 549,850,430	$ 42,823,293	$ (16,575,966)	$ (4,691,502)	$ 571,406,256	$ (12,106,018)	$ 559,300,238
	GENERAL PLANT							
389.2	Land Rights	$ 14,800	$ 407	$ -	$ -	$ 15,207	$ (2,547)	$ 12,659
390.1	Easton Serv Center	3,766,087	322,148	(78,737)	-	4,009,499	(671,591)	3,337,908
390.1	Lebanon Serv Ctr	3,035,180	188,469	(104,866)	-	3,118,784	(522,396)	2,596,388
390.1	South Bldg Reading	24,249,976	1,092,299	-	-	25,342,274	(4,244,831)	21,097,443
390.1	Structures	7,426,845	488,341	-	(85,549)	7,829,637	(1,311,464)	6,518,173
390.1	York Serv Center	3,773,706	209,705	-	-	3,983,411	(667,221)	3,316,189
390.2	Corp Hqtrs Reading	1,623,551	90,647	-	-	1,714,197	(287,128)	1,427,069
390.2	Easton Ser Ctr	756,468	116,782	-	-	873,250	(146,269)	726,981
390.2	Land/Yard Improvem	2,666,882	169,861	-	-	2,836,743	(475,154)	2,361,588
390.2	Lebanon Ser Ctr	770,154	23,374	-	-	793,528	(132,916)	660,612
390.2	York Ser Ctr	1,096,229	46,769	-	-	1,142,997	(191,452)	951,545
390.3	Transfered LH	3,456	838	-	-	4,293	(719)	3,574
391.1	Office Furniture	14,419,236	748,509	(521,544)	-	14,646,201	(2,453,239)	12,192,962
391.15	Office Machines	5,920,633	-	-	-	5,920,633	(991,706)	4,928,927
391.2	Personal Computers	1,964,996	747,802	(460,109)	(12,498)	2,240,191	(375,232)	1,864,959
391.25	Data Proc Smart Me	-	72,062	-	14,012	86,074	-	86,074
391.25	Information Sys	256	(1,337)	(351)	(1,513)	(2,944)	493	(2,451)
392	Transportation equip	51,829	34,679	-	(7,004)	79,504	(13,317)	66,187
392.4	Pole Trailers	435,261	25,554	-	-	460,815	(77,186)	383,628
392.5	Van Trailers	78,354	717	-	-	79,071	(13,244)	65,826
393	Stores Equipment	1,390,709	30,785	(17,284)	-	1,404,210	(235,205)	1,169,005
394	Tools shop garage	6,491,729	508,233	(315,486)	-	6,684,476	(1,119,650)	5,564,826
395	Laboratory equip	3,130,011	466	(82,793)	-	3,047,684	(510,487)	2,537,197

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/13 to 3/31/14
Book Reserves

Acct No	Description	Balance 3/31/13	Actual Activity			Balance 3/31/14	Adjustments	Adjusted Balance 3/31/14
			Accruals	Retirements	Transfers/ Adjustments			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
396	Power operated equip	609,115	4,001	-	-	613,115	(102,697)	510,418
397	Communication Equipt	25,010,698	975,149	(2,068,186)	(4,130)	23,913,531	(12,674,172)	11,239,360
398	Miscellaneous equipt	2,539,048	62,418	(96,006)	-	2,505,460	(419,665)	2,085,795
399	EASTON BLDG ARC	3,776	145	-	-	3,921	(3,921)	-
399	GEN BLDG ARC	28,466	1,193	-	-	29,659	(29,659)	-
399	LEBANON BLDG ARC	3,875	150	-	-	4,024	(4,024)	-
399	READING SOUTH BLDG ARC	7,658	277	-	-	7,935	(7,935)	-
399	YORK BLDG ARC	2,641	101	-	-	2,742	(2,742)	-
	TOTAL GENERAL PLANT	$ 111,271,623	$ 5,960,544	$ (3,745,361)	$ (96,684)	$ 113,390,122	$ (27,687,278)	$ 85,702,844
	NUCLEAR PRODUCTION							
326	TMI#2 ARC	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
Total	TOTAL	$ 929,077,014	$ 58,130,587	$ (22,443,057)	$ (5,448,778)	$ 959,315,767	$ (289,002,712)	$ 670,313,056

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/13 to 3/31/14
Calculated Reserves

Acct No	Description	Balance 3/31/13	Actual Activity			Balance 3/31/14	Adjustments	Adjusted Balance 3/31/14
			Accruals	Retirements	Transfers/ Adjustments			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	INTANGIBLE PLANT							
303	Misc. Intangible Plant	$ 27,072,400	$ 5,331,902	$ -	$ -	$ 32,404,302	$ (5,427,721)	$ 26,976,581
303	Smart Meter Software		-			-	-	-
	TOTAL INTANGIBLE PLANT	$ 27,072,400	$ 5,331,902	$ -	$ -	$ 32,404,302	$ (5,427,721)	$ 26,976,581
	TRANSMISSION PLANT							
	TRANSMISSION PLANT							
350.12	Easements - Trans. Subs.	$ 101,129	$ 4,372	$ -	$ -	$ 105,501	$ (105,501)	$ -
350.22	Easements - Trans. Lines	13,729,903	401,402	-	-	14,131,305	(14,131,305)	-
352.1	Structures, Improvements	2,939,395	111,806	-	-	3,051,201	(3,051,201)	-
352.2	Clearing, Grading Of Land	0	8,823	-	-	8,823	(8,823)	-
353	Station Equipment	41,128,807	2,904,546	(1,022,430)	-	43,010,923	(43,010,923)	-
354	Towers And Fixtures	21,584,172	494,114	(43,714)	-	22,034,572	(22,034,572)	-
355	Poles And Fixtures	14,341,588	646,711	(505,057)	-	14,483,242	(14,483,242)	-
356.1	Overhd Conductr, Devices	22,209,775	867,618	(550,529)	-	22,526,864	(22,526,864)	-
356.2	Clearing, Grading of Land	3,137,912	188,225	-	-	3,326,137	(3,326,137)	-
358	Undergrnd Conductr,Devices	23,958	27,241	-	-	51,199	(51,199)	-
359	Roads And Trails	527,886	16,807	-	-	544,693	(544,693)	-
359.1	ARC Transmission	2,511	104	-	-	2,614	(2,614)	-
	TOTAL TRANSMISSION PLANT	$ 119,727,036	$ 5,671,769	$ (2,121,730)	$ -	$ 123,277,074	$ (123,277,074)	$ -
	DISTRIBUTION PLANT							
360.12	Easements - Dist. Subs.	$ 164,777	$ 7,253	$ -	$ -	$ 172,030	$ -	$ 172,030
360.22	Easements - Dist. Lines	12,873,434	416,315	-	-	13,289,749	-	13,289,749
361.1	Structures, Improvements	5,601,618	312,690	(2,322)	-	5,911,986	-	5,911,986
361.2	Clearing, Grading of Land	713,597	6,105	-	-	719,702	-	719,702
362	Station Equipment	54,799,027	3,102,128	(1,401,555)	-	56,499,600	-	56,499,600
364	Poles, Towers And Fixtures	60,912,239	4,973,748	(1,998,952)	-	63,887,035	-	63,887,035
365	Overhd Conductr, Devices	52,167,632	5,793,852	(5,548,499)	-	52,412,985	-	52,412,985
365.1	Clearing, Grading of Land	14,236,200	1,940,552	-	-	16,176,752	-	16,176,752
366	Underground Conduit	11,237,934	529,598	(7,411)	-	11,760,121	-	11,760,121
367	Undergrnd Conductr,Devices	61,866,658	5,611,391	(1,549,128)	-	65,928,921	-	65,928,921
368	Line Transformers	90,139,633	8,360,742	(3,933,333)	-	94,567,042	-	94,567,042
369	Services	14,812,424	1,605,057	(62,001)	-	16,355,480	-	16,355,480
369	Underground Conduit	39,820,229	2,215,323	-	-	42,035,552	-	42,035,552
370	Meters	9,631,099	2,670,943	(1,453,354)	-	10,848,688	(10,848,688)	0
370	Smart Meters Res	-	49,957	(6,036)	-	43,921	-	43,921
371	Inst. On Cust. Prem.	1,710,387	144,274	(21,779)	-	1,832,882	-	1,832,882
373.1	Street Light - Oh, Ug Lines	2,063,532	310,662	(591,596)	-	1,782,598	-	1,782,598
374	ARC Distribution	20,672	759	-		21,431	(21,431)	0
	TOTAL DISTRIBUTION PLANT	$ 432,771,092	$ 38,051,349	$ (16,575,966)	$ -	$ 454,246,475	$ (10,870,119)	$ 443,376,357
	GENERAL PLANT							
389.2	Easements	$ 15,175	$ 407	$ -	$ -	$ 15,582	$ (2,610)	$ 12,972
390.1	Structures, Improvements	37,467,445	2,360,604	(183,603)	-	39,644,446	(6,640,445)	33,004,001
390.2	Clearing, Grading of Land	7,309,879	344,069	-	-	7,653,948	(1,282,036)	6,371,912
390.3	Struct Imprv, Leasehold Imp	3,455	462	-	-	3,917	(656)	3,261
391.1	Office Furn., Mech. Equip.	14,074,756	1,010,247	(521,544)	-	14,563,459	(2,439,379)	12,124,080
391.15	Office Machines	5,920,633	354,646	-	-	6,275,279	(1,051,109)	5,224,170
391.2	Data Processing Equipment	1,728,980	210,826	(460,109)	-	1,479,697	(247,849)	1,231,848
391.25	Data Proc Smart Meters	-	115,075	-	-	115,075	-	115,075
391.25	Information System	381	(3,568)	(351)	-	(3,538)	593	(2,946)
392	Transportation Equipment	535,602	67,046	-	-	602,648	(100,944)	501,704
393	Stores Equipment	1,331,196	30,815	(17,284)	-	1,344,727	(225,242)	1,119,486
394	Tools, Shop, Garage Equip.	6,832,459	482,124	(315,486)	-	6,999,097	(1,172,349)	5,826,748
395	Laboratory Equipment	2,967,426	618	(82,793)	-	2,885,251	(483,280)	2,401,972
396	Power Operated Equipment	335,908	3,905	-	-	339,813	(56,919)	282,894
397	Communication Equipment	17,348,936	996,453	(2,068,186)	-	16,277,203	(8,626,918)	7,650,286
398	Misc. Equipment	2,377,848	62,828	(96,006)	-	2,344,670	(392,732)	1,951,938
399.1	ARC General Plant	46,416	1,866	-		48,282	(48,282)	-
	TOTAL GENERAL PLANT	$ 98,296,495	$ 6,038,423	$ (3,745,361)	$ -	$ 100,589,557	$ (22,770,157)	$ 77,819,400
	TOTAL	$ 677,867,022	$ 55,093,443	$ (22,443,057)	$ -	$ 710,517,409	$ (162,345,070)	$ 548,172,338

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT V-A-3:

"Provide supporting schedules which indicate the procedures and calculations employed to develop the original cost plant and applicable reserves to the test year end as submitted in the current proceeding."

RESPONSE:

Met-Ed Exhibit RAD- 49 Attachment A presents the example showing the methodology used to update original cost plant and reserves from 3/31/13 to 3/31/14 (the historic test year-end) and to 3/31/15 (the future test year-end) and to 4/30/2016 (the fully future test year). The procedure applied is the same as has been used and found acceptable in prior base rate cases for projecting the future year original cost plant related data.

The example depicts a mass property remaining life investment set, Account 373, Street Lighting and Signal Systems.

Metropolitan Edison Company
Original Cost-Plant & Depreciation Reserves
Activity Updated from 3/31/13 through 3/31/14 and 3/31/15 and 4/30/16

MASS PROPERTY EXAMPLE

Line No	Description	Plant in Service	Target Reserves	Book Reserves
		(1)	(2)	(3)
	Distribution - 373.1 Street Lighting & Signal Systems			
1	Balance at 3/31/13	11,516,382	2,063,532	3,112,557
2	Accrual on Above		300,578	
3	Retirements	(591,596)	(591,596)	(591,596)
4	Accrual on Retirements		(7,720)	
5	Transfers & Adjustments	-	-	
6	Accrual on Transfers & Adjustments		-	
7	Additions	1,364,349		
8	Accrual on Additions		17,805	
9	Book Accrual			(69,008)
10	Book Activity-Other			387,276
11	Balance at 3/31/14	12,289,135	1,782,599	2,839,229
12	Accrual on 3/31/14 Plant		320,746	
13	Retirements	-	-	-
14	Accrual on Retirements		-	
15	Transfers & Adjustments	-	-	
16	Accrual on Transfers & Adjustments		-	
17	Additions	-		
18	Accrual on Additions		-	
19	Book Accrual			321,122
20	Book Activity-Other			-
21	Balance at 3/31/15	12,289,135	2,103,345	3,160,351
12	Accrual on 4/30/15 Plant		320,746	
13	Retirements	-	-	-
14	Accrual on Retirements		-	
15	Transfers & Adjustments	-	-	
16	Accrual on Transfers & Adjustments		-	
17	Additions	-		
18	Accrual on Additions		-	
19	Book Accrual			321,122
20	Book Activity-Other			-
21	Balance at 4/30/16	12,289,135	2,424,091	3,481,473

Key to Rates:

2012 Depreciation Service Life Accrual Rate 2.61%

METROPOLITAN EDISON COMPANY

Original Cost Plant and Reserve and Accrual Rate Adjustments for Rate Case Purposes
(Fully Projected Future Test Year)

FILING REQUIREMENT V-A-4:

"Provide a schedule showing details of rate case adjustments."

RESPONSE:

This response provides original cost plant and reserve adjustments for rate case purposes at 4/30/16, the fully projected future test year-ended. This information is in support of Met-Ed Exhibit RAD-46 Attachment B.

The following provide detail for plant and reserve adjustment items:

1. Asset Retirement Costs: No claim is being made for the Asset Retirement Costs related to the implementation of Statement of Financial Accounting Standards Statement 143, Accounting for Asset Retirement Obligations or FIN 47, Accounting for Conditional Asset Retirement Obligations. The Plant in Service was reduced by $95,358,364; book reserves were reduced by $95,344,166; and calculated reserves were reduced by $22,949.

2. FERC Transmission Plant was removed because it is non-jurisdictional. Transmission Plant in Service was reduced by $454,163,285 and the budgeted book and calculated reserve accruals were reduced by $155,934,333 and $130,390,153 respectively.

3. A portion of Intangible Plant associated with the FERC Transmission Plant was removed. Intangible Plant in Service was reduced by $9,694,591; Intangible Plant book reserves were reduced by $6,012,241; and Intangible Plant calculated reserves were reduced by $7,444,387.

4. A portion of General Plant associated with FERC Transmission Plant was removed. General Plant in Service was reduced by $43,569,748; General Plant book reserves were reduced by $30,270,230; and General Plant calculated reserves were reduced by $25,593,811.

5. Legacy meters were removed. Meter plant in service was reduced by $66,794,533; meter book reserves were reduced by $16,631,748; and meter calculated reserves were reduced by $16,672,615.

METROPOLITAN EDISON COMPANY

Original Cost Plant and Reserve and Accrual Rate Adjustments for Rate Case Purposes
(Future Test Year)

FILING REQUIREMENT V-A-4:

"Provide a schedule showing details of rate case adjustments."

RESPONSE:

This response provides original cost plant and reserve adjustments for rate case purposes at 3/31/15, the future test year-ended. This information is in support of Met-Ed Exhibit RAD-47 Attachment B.

The following provide detail for plant and reserve adjustment items:

1. Asset Retirement Costs: No claim is being made for the Asset Retirement Costs related to the implementation of Statement of Financial Accounting Standards Statement 143, Accounting for Asset Retirement Obligations or FIN 47, Accounting for Conditional Asset Retirement Obligations. The Plant in Service was reduced by $95,358,364; book reserves were reduced by $95,343,344; and calculated reserves were reduced by $22,190.

2. FERC Transmission Plant was removed because it is non-jurisdictional. Transmission Plant in Service was reduced by $433,209,181 and the budgeted book and calculated reserve accruals were reduced by $151,083,591 and $125,510,429 respectively.

3. A portion of Intangible Plant associated with the FERC Transmission Plant was removed. Intangible Plant in Service was reduced by $6,968,446; Intangible Plant book reserves were reduced by $5,488,712; and Intangible Plant calculated reserves were reduced by $6,292,334.

4. A portion of General Plant associated with FERC Transmission Plant was removed. General Plant in Service was reduced by $43,409,672; General Plant book reserves were reduced by $28,831,646; and General Plant calculated reserves were reduced by $23,934,946.

5. Legacy meters were removed. Meter plant in service was reduced by $66,794,533; meter book reserves were reduced by $14,727,733; and meter calculated reserves were reduced by $13,647,379.

METROPOLITAN EDISON COMPANY

Original Cost Plant and Reserve and Accrual Rate Adjustments for Rate Case Purposes
(Historical Test Year)

FILING REQUIREMENT V-A-4:

"Provide a schedule showing details of rate case adjustments."

RESPONSE:

This response provides original cost plant and reserve adjustments for rate case purposes at 3/31/14, the historic test year-ended. This information is in support of Met-Ed Exhibit RAD-48 Attachment B.

The following provide detail for plant and reserve adjustment items:

1. Asset Retirement Costs: No claim is being made for the Asset Retirement Costs related to the implementation of Statement of Financial Accounting Standards Statement 143, Accounting for Asset Retirement Obligations or FIN 47, Accounting for Conditional Asset Retirement Obligations. The Plant in Service was reduced by $95,358,364; book reserves were reduced by $95,342,585; and calculated reserves were reduced by $22,190.

2. FERC Transmission Plant was removed because it is non-jurisdictional. Transmission Plant in Service was reduced by $397,455,541 and the budgeted book and calculated reserve accruals were reduced by $148,795,864 and $123,277,074 respectively.

3. A portion of Intangible Plant associated with the FERC Transmission Plant was removed. Intangible Plant in Service was reduced by $6,478,107; Intangible Plant book reserves were reduced by $5,092,397; and Intangible Plant calculated reserves were reduced by $5,427,721.

4. A portion of General Plant associated with FERC Transmission Plant was removed. General Plant in Service was reduced by $42,590,158; General Plant book reserves were reduced by $27,687,278; and General Plant calculated reserves were reduced by $22,770,157.

5. Legacy Meters were removed. Meter plant in service was reduced by $66,794,533; meter book reserves were reduced by $12,084,587; and meter calculated reserves were reduced by $10,848,688.

METROPOLITAN EDISON COMPANY

Annual Depreciation Review on Capital Plant Investments

FILING REQUIREMENT V-B-2

"Supply a schedule by account or by depreciable group showing the survivor curve or interim survivor curve or interim survivor curse and annual accrual rate estimated to be appropriate:

a. For the purpose of this filing
b. For the purposes of the most recent filing prior to the current proceeding.
c. Supply an explanation for any major change in annual accrual rate by account or by depreciable group
d. Supply a comprehensive statement of major changes in depreciation methods, procedures and techniques and the effect of the changes upon accumulated and annual depreciation, if any."

FILING REQUIREMENT V-C

"Where the retirement rate actuarial method of mortality is utilized, set forth representative examples including charts depicting the observed and estimated survivor curves and a tabular presentation of the observed and estimated life tables plotted on the chart. Other analysis results shall be subject to request."

FILING REQUIREMENT V-D Item 2

"Provide representative examples of detail calculations by vintage at account or at a more detailed level, as performed for those purposes. Other vintage detail calculations shall be subject to request."

FILING REQUIREMENT V-E

"Provide a description of depreciation methods utilized in calculating annual depreciation amounts and depreciation reserves, together with a discussion of significant factors which were considered in arriving at estimates of service life and forecast retirements by facilities, accounts or sub-accounts as applicable."

RESPONSE:

V-B-2:

See Met-Ed Exhibit RAD-53 Attachment A, Pages 1-2 for the fully projected future test year. See Met-Ed Exhibit RAD-53 Attachment A, Pages 3-4 for the future test year. See Met-Ed Exhibit RAD-53 Attachment A, pages 5-6 for the historical test year.

See Met-Ed Exhibit RAD-53 Attachment B for the 2014 Annual Depreciation Report.

V-C:

See Met-Ed Exhibit RAD-53 Attachment C.

V-D Item 2:

See Met-Ed Exhibit RAD-53 Attachment D for Annual Depreciation Report details.

V-E:

See Met-Ed Exhibit RAD-53 Attachment B for the 2014 Annual Depreciation Report.

Metropolitan Edison Company
Accrual Expense after Adjustment-Claim Basis
At Future Year from May 2015 to April 2016

Acct No	Description	Adjusted Depreciable Base	Accrual Rate Ave Remaining Life Basis	Accrual Expense Amount
		(1)	(2)	(3)
	INTANGIBLE PLANT			
303	Miscellaneous Intangible Plant	$ 48,183,564	12.86%	$ 6,196,406
303	Smart Meters	13,103,518	14.29%	1,872,493
	TOTAL INTANGIBLE PLANT	$ 61,287,082	13.17%	$ 8,068,899
	TRANSMISSION PLANT			
	TRANSMISSION PLANT			
350.12	Land Rights- subs	$ -	1.50%	$ -
350.22	Land Rights- lines	-	1.50%	-
352.1	Structures	-	1.84%	-
352.2	Clearing Costs	-	1.84%	-
353	Station Equipment	-	1.68%	-
354	Towers and Fixtures	-	1.16%	-
355	Poles and Fixtures	-	1.46%	-
3356.1	Overhead Conductors	-	1.32%	-
356.2	Clearing Costs	-	1.23%	-
358	Underground Conductors	-	2.51%	-
359	Roads & Trails	-	2.25%	-
	TOTAL TRANSMISSION PLANT	$ -		$ -
	DISTRIBUTION PLANT			
360.12	Land Rights-subs	$ 611,470	1.47%	$ 8,989
360.22	Land Rights-lines	28,320,720	1.47%	
361.1	Structures	12,746,076	2.43%	309,730
361.2	Clearing Costs	366,045	2.43%	
362	Station Equipment	216,797,725	1.56%	3,382,045
364	Poles, Towers and Fixtures	354,210,686	1.32%	4,675,581
365	Overhead Conductors	368,193,014	1.71%	6,296,101
365.1	Clearing Costs	131,739,866	1.52%	2,002,446
366	Underground Conduit	30,296,760	1.74%	527,164
367	Underground Conductors	203,212,529	2.85%	5,791,557
368	Line Transformers	502,265,379	2.14%	10,748,479
369	Overhead Services	71,066,339	2.28%	1,620,313
369.1	Underground Services	98,458,792	2.23%	2,195,631
370	Meters	0	4.19%	0
370.1	Smart Meters	11,620,142	6.67%	775,063
371	Installed on Customer Premises	4,519,593	3.19%	144,175
373	Street Lighting & Signal Systems	12,289,135	2.77%	340,409
	TOTAL DISTRIBUTION PLANT	$ 2,046,714,271	1.90%	$ 38,817,683

Metropolitan Edison Company
Accrual Expense after Adjustment-Claim Basis
At Future Year from May 2015 to April 2016

Acct No	Description	Adjusted Depreciable Base	Accrual Rate Ave Remaining Life Basis	Accrual Expense Amount
		(1)	(2)	(3)
	GENERAL PLANT			
389.1	Land Rights	$ 15,050	2.21%	$ 333
390.1	Structures	72,817,578	2.45%	1,784,031
390.2	Clearing	10,378,180	3.52%	365,312
390.3	Structures and Improvements LH	13,948	3.52%	491
391.1	Office Furniture & Equipment	13,845,120	4.12%	570,419
391.15	Office Machines	4,928,927	0.00%	0
391.2	Data Processing	3,851,932	6.72%	258,850
391.25	Data Processing Smart Meters	9,299,254	20.00%	1,859,851
391.25	Information Systems	(9,772)	13.03%	(1,273)
392	Transportation	4,316,320	4.76%	205,457
393	Stores Equipment	1,175,009	0.88%	10,340
394	Tools, Shop, & Garage Equipment	9,750,097	4.19%	408,529
395	Laboratory Equipment	2,537,197	0.00%	25
396	Power Operated Equipment	625,755	1.72%	10,763
397	Communications Equipment	15,990,851	3.01%	481,325
398	Miscellaneous Equipment	2,153,311	1.84%	39,621
	TOTAL GENERAL PLANT	$ 151,688,757	3.95%	$ 5,994,074
	TOTAL	$ 2,259,690,109	2.34%	$ 52,880,656

Metropolitan Edison Company
Accrual Expense after Adjustment-Claim Basis
At Future Year from April 2014 to March 2015

Acct No	Description	Adjusted Depreciable Base	Accrual Rate Ave Remaining Life Basis	Accrual Expense Amount
		(1)	(2)	(3)
	INTANGIBLE PLANT			
303	Miscellaneous Intangible Plant	$ 34,634,219	12.86%	$ 4,453,961
303	Smart Meters	2,159,907	14.29%	308,651
	TOTAL INTANGIBLE PLANT	$ 36,794,126	12.94%	$ 4,762,612
	TRANSMISSION PLANT			
	TRANSMISSION PLANT			
350.12	Land Rights- subs	$ -	1.50%	$ -
350.22	Land Rights- lines	-	1.50%	-
352.1	Structures	-	1.84%	-
352.2	Clearing Costs	-	1.84%	-
353	Station Equipment	-	1.68%	-
354	Towers and Fixtures	-	1.16%	-
355	Poles and Fixtures	-	1.46%	-
3356.1	Overhead Conductors	-	1.32%	-
356.2	Clearing Costs	-	1.23%	-
358	Underground Conductors	-	2.51%	-
359	Roads & Trails	-	2.25%	-
	TOTAL TRANSMISSION PLANT	$ -		$ -
	DISTRIBUTION PLANT			
360.12	Land Rights-subs	$ 611,470	1.47%	$ 8,989
360.22	Land Rights-lines	28,320,720	1.47%	
361.1	Structures	12,746,076	2.43%	309,730
361.2	Clearing Costs	366,045	2.43%	
362	Station Equipment	212,972,648	1.56%	3,322,373
364	Poles, Towers and Fixtures	354,210,686	1.32%	4,675,581
365	Overhead Conductors	368,193,014	1.71%	6,296,101
365.1	Clearing Costs	131,739,866	1.52%	2,002,446
366	Underground Conduit	30,296,760	1.74%	527,164
367	Underground Conductors	203,212,529	2.85%	5,791,557
368	Line Transformers	450,297,576	2.14%	9,636,368
369	Overhead Services	71,066,339	2.28%	1,620,313
369.1	Underground Services	98,458,792	2.23%	2,195,631
370	Meters	0	4.19%	0
370.1	Smart Meters	2,241,360	6.67%	149,499
371	Installed on Customer Premises	4,519,593	3.19%	144,175
373	Street Lighting & Signal Systems	12,289,135	2.77%	340,409
	TOTAL DISTRIBUTION PLANT	$ 1,981,542,609	1.87%	$ 37,020,336

Metropolitan Edison Company
Accrual Expense after Adjustment-Claim Basis
At Future Year from April 2014 to March 2015

Acct No	Description	Adjusted Depreciable Base	Accrual Rate Ave Remaining Life Basis	Accrual Expense Amount
		(1)	(2)	(3)
	GENERAL PLANT			
389.1	Land Rights	$ 15,050	2.21%	$ 333
390.1	Structures	72,817,247	2.45%	1,784,023
390.2	Clearing	10,378,180	3.52%	365,312
390.3	Structures and Improvements LH	13,948	3.52%	491
391.1	Office Furniture & Equipment	13,845,120	4.12%	570,419
391.15	Office Machines	4,928,927	0.00%	0
391.2	Data Processing	3,851,932	6.72%	258,850
391.25	Data Processing Smart Meters	6,355,799	20.00%	1,271,160
391.25	Information Systems	(9,772)	13.03%	(1,273)
392	Transportation	3,521,048	4.76%	167,602
393	Stores Equipment	1,175,009	0.88%	10,340
394	Tools, Shop, & Garage Equipment	9,750,097	4.19%	408,529
395	Laboratory Equipment	2,537,197	0.00%	25
396	Power Operated Equipment	625,755	1.72%	10,763
397	Communications Equipment	15,990,851	3.01%	481,325
398	Miscellaneous Equipment	2,153,311	1.84%	39,621
	TOTAL GENERAL PLANT	$ 147,949,698	3.63%	$ 5,367,520
	TOTAL	$ 2,166,286,433	2.18%	$ 47,150,468

Metropolitan Edison Company
Accrual Expense after Adjustment-Claim Basis
At Future Year from April 2013 to March 2014

Acct No	Description	Adjusted Depreciable Base (1)	Accrual Rate Ave Remaining Life Basis (2)	Accrual Expense Amount (3)
	INTANGIBLE PLANT			
303	Miscellaneous Intangible Plant	$ 32,197,158	13.85%	$ 4,459,306
303	Smart Meters	0	14.29%	0
	TOTAL INTANGIBLE PLANT	$ 32,197,158	13.85%	$ 4,459,306
	TRANSMISSION PLANT			
	TRANSMISSION PLANT			
350.12	Land Rights- subs	$ -	1.50%	$ -
350.22	Land Rights- lines	0	1.50%	
352.1	Structures	0	1.83%	0
352.2	Clearing Costs	0	1.83%	
353	Station Equipment	0	1.66%	0
354	Towers and Fixtures	0	1.19%	0
355	Poles and Fixtures	0	1.43%	0
356.1	Overhead Conductors	0	1.29%	0
356.2	Clearing Costs	0	1.23%	0
358	Underground Conductors	0	2.46%	0
359	Roads & Trails	0	2.25%	0
	TOTAL TRANSMISSION PLANT	$ -		$ -
	DISTRIBUTION PLANT			
360.12	Land Rights-subs	$ 611,470	1.47%	$ 8,989
360.22	Land Rights-lines	28,320,720	1.47%	
361.1	Structures	12,746,076	2.46%	313,553
361.2	Clearing Costs	366,045	2.46%	
362	Station Equipment	203,494,152	1.54%	3,133,810
364	Poles, Towers and Fixtures	354,210,686	1.35%	4,781,844
365	Overhead Conductors	368,193,014	1.67%	6,148,823
365.1	Clearing Costs	131,739,866	1.53%	2,015,620
366	Underground Conduit	30,296,760	1.75%	530,193
367	Underground Conductors	203,212,529	2.85%	5,791,557
368	Line Transformers	392,737,933	2.14%	8,404,592
369	Overhead Services	71,066,339	2.30%	1,634,526
369.1	Underground Services	98,458,792	2.25%	2,215,323
370	Meters	-	4.07%	-
370.1	Smart Meters	1,554,367	6.67%	103,676
371	Installed on Customer Premises	4,519,593	3.23%	145,983
373	Street Lighting & Signal Systems	12,289,135	2.61%	320,746
	TOTAL DISTRIBUTION PLANT	$ 1,913,817,477	1.86%	$ 35,549,235

Metropolitan Edison Company
Accrual Expense after Adjustment-Claim Basis
At Future Year from April 2013 to March 2014

Acct No	Description	Adjusted Depreciable Base	Accrual Rate Ave Remaining Life Basis	Accrual Expense Amount
		(1)	(2)	(3)
	GENERAL PLANT			
389.1	Land Rights	$ 15,050	2.25%	$ 339
390.1	Structures	71,376,932	2.76%	1,970,003
390.2	Clearing	10,378,180	2.76%	286,438
390.3	Structures and Improvements LH	13,948	2.76%	385
391.1	Office Furniture & Equipment	13,845,120	5.99%	829,323
391.15	Office Machines	4,928,927	5.99%	295,243
391.2	Data Processing	3,851,932	5.99%	230,731
391.25	Data Processing Smart Meters	902,575	20.00%	180,515
391.25	Information Systems	(9,772)	5.99%	(585)
392	Transportation	888,253	5.98%	53,118
393	Stores Equipment	1,175,009	2.17%	25,498
394	Tools, Shop, & Garage Equipment	9,750,097	4.39%	428,029
395	Laboratory Equipment	2,537,197	0.02%	507
396	Power Operated Equipment	625,755	0.56%	3,504
397	Communications Equipment	15,990,851	2.86%	457,338
398	Miscellaneous Equipment	2,153,311	2.39%	51,464
	TOTAL GENERAL PLANT	$ 138,423,365	3.48%	$ 4,811,850
	TOTAL	$ 2,084,438,000	2.15%	$ 44,820,391

METROPOLITAN EDISON COMPANY

2014 Annual Depreciation Report
Based on Data at 12/31/2013

To the Pennsylvania Public Utility Commission
Per Reference No. M-110300F2013ADR

June 2014

METROPOLITAN EDISON COMPANY

2014 Annual Depreciation Report
Based on Data at 12/31/2013

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METROPOLITAN EDISON COMPANY
2014 ANNUAL DEPRECIATION REPORT
YEAR ENDED DECEMBER, 31, 2013
EXECUTIVE SUMMARY

Introduction

In accordance with 52 Pa. Code, Chapter 73, the attached report provides the following:

- A summary of plant transactions, including the 2013 retirements expressed as a percent of the beginning plant balance
- A summary of depreciation reserve activity, including the reserve as a percent of the plant balance
- The calculation of remaining life depreciation accrual rates as of December 31, 2013
- A summary of cost of removal, gross and net salvage.

Metropolitan Edison Company (Met-Ed) is requesting the Pennsylvania Public Utility Commission (PaPUC) to approve this filing, for accounting purposes only, so that the new depreciation rates can be implemented effective January 1, 2014 to be consistent across all FirstEnergy Pennsylvania Operating Companies.

The annual accrual rate calculations are based on a depreciation service life study of Transmission, Distribution and General Plant data filed with the PaPUC in 2010 that included data through the year ended 2009. The annual accrual rate calculations were based on the same service life and survivor curve estimates and also on the same group procedures and basis as those submitted to the PaPUC in 2010.

Included with this Executive Summary is a table that sets forth a comparison of the original cost, book reserve and calculated annual depreciation accruals by function at December 31, 2011; December 31, 2012; and December 31, 2013. The annual accrual amounts, as summarized, are presented as a percent of original cost for each function and for the total Company. The overall composite depreciation accrual rate related to depreciable electric plant in service decreased from 2.09 percent in 2012 to 2.08 percent for 2013.

Depreciation Method

For most plant accounts, depreciation accruals and accrued depreciation were calculated using the straight line remaining life method and the average service life broad group (ASL-BG) procedure for all vintages.

The depreciation calculations were based on the attained ages and estimated service life characteristics for each depreciable group of electric plant. For certain general plant accounts, the amortization amounts, annual and accrued, were based on the age of the vintage and the selected amortization period.

The service life study filed with the PaPUC in 2010 determined the appropriate service life and survivor curves utilized in the accrual rate calculations as explained further below.

Service Life

The method of estimating service life consisted of compiling the service life history of the plant accounts, sub-accounts or depreciable groups through 2009. The history was then reduced to trends through the use of acceptable actuarial techniques. Lastly, the trend of survivors for each depreciable group was forecasted on the basis of interpretations of past trends and consideration of Company plans for the future. The combination of the historical trend and the estimated future trend developed a complete pattern of life characteristics from which the average service life was derived.

Survivor Curves

Iowa type survivor curves were used to reflect the expected dispersion of retirements, thus providing a consistent method of estimating service lives and depreciation for mass property. For life span groups, the estimate of life characteristics is consistent because the calculated lives of the units within a group are obtained by employing a single probable retirement date for the entire group.

Plant and Reserve Activity

Schedule 1 provides the net original cost balance at December 31, 2013, the average service life and the Iowa Survivor Curve for each account along with the average remaining life, annual depreciation accrual and accrual rate. The functional plant level accrual rates for 2013 did not change significantly from 2012.

Schedule 2 provides the plant activity during 2013 by account and functional group. It sets forth the original cost at the beginning of the year, January 1, 2013; additions; retirements; transfers or adjustments; the balance at the end of the year, December 31, 2013; and the retirements expressed as a percent of the beginning plant balance.

Schedule 3 summarizes the reserve activity during 2013 by account and functional group. It includes the book depreciation reserve balance at the beginning of the year, January 1, 2013; annual accruals; retirements; gross salvage; cost of removal; transfers or adjustments; the balance at the end of the year, December 31, 2013; and the book reserve as a percent of the ending plant balance.

Net Salvage Analysis

Schedule 4 reports the 2013 and a five year rolling average for Cost of Removal, Gross and Net Salvage. The five-year rolling average is based on 2009 through 2013 experience. Since this report relates primarily to Pennsylvania rate regulation practices, no adjustments for expected net salvage were made to either the annual depreciation accrual or the calculated accrued depreciation for individual accounts. Met-Ed, in general, records cost of removal and salvage directly to expense (Account 403, Depreciation Expense) in the year the transactions occur rather than to the depreciation reserve account (Account 108, Accumulated Depreciation).

METROPOLITAN EDISON COMPANY

ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL
DEPRECIATION ACCRUALS BY FUNCTION RELATED TO ELECTRIC PLANT
AT DECEMBER 31, 2011; AT DECEMBER 31, 2012; AND AT DECEMBER 31, 2013
($000)

	2011	2012	2013
Intangible Plant (Amortizable)			
Original Cost (Depreciable)	36,994	36,948	38,039
Book Accrued Depreciation	23,489	26,622	29,670
Book Reserve % of O.C.	63.49%	72.05%	78.00%
Original Cost (Depreciated)	13,505	10,326	8,369
Annual Depreciation Expense	4,049	3,916	3,776
Annual % of O.C.	10.95%	10.60%	9.93%
Transmission Plant			
Original Cost (Depreciable)	349,923	364,613	391,772
Book Accrued Depreciation	139,053	144,200	147,654
Book Reserve % of O.C.	39.74%	39.55%	37.69%
Original Cost (Depreciated)	210,870	220,413	244,118
Annual Depreciation Expense	5,203	5,429	5,919
Annual % of O.C.	1.49%	1.49%	1.51%
Distribution Plant			
Original Cost (Depreciable)	1,798,801	1,915,548	1,962,660
Book Accrued Depreciation	520,957	546,639	563,866
Book Reserve % of O.C.	28.96%	28.54%	28.73%
Original Cost (Depreciated)	1,277,844	1,368,909	1,398,794
Annual Depreciation Expense	35,150	37,200	38,440
Annual % of O.C.	1.95%	1.94%	1.96%
General Plant			
Original Cost (Depreciable)	176,247	176,023	180,375
Book Accrued Depreciation	107,986	109,853	111,849
Book Reserve % of O.C.	61.27%	62.41%	62.01%
Original Cost (Depreciated)	68,261	66,170	68,526
Annual Depreciation Expense	5,300	5,446	5,449
Annual % of O.C.	3.01%	3.09%	3.02%
Total Company (Depreciable)			
Original Cost (Depreciable)	2,361,965	2,493,132	2,572,846
Book Accrued Depreciation	791,486	827,314	853,039
Book Reserve % of O.C.	33.51%	33.18%	33.16%
Original Cost (Depreciated)	1,570,479	1,665,818	1,719,807
Annual Depreciation Expense	49,702	51,992	53,584
Annual % of O.C.	2.10%	2.09%	2.08%
Non-Depreciable Plant	103,852	103,852	105,081
Total Plant In Service	2,465,817	2,596,984	2,677,927

METROPOLITAN EDISON COMPANY

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCURALS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2013

	ACCOUNT AND DESCRIPTION (1)	PROBABLE RETIREMENT YEAR (2)	IOWA SURVIVOR CURVE (3)	GROSS ORIGINAL COST 12/31/2013 (4)	BOOK RESERVE 12/31/2013 (5)	NET ORIGINAL COST 12/31/2013 (6)	AVERAGE SERVICE LIFE (Yrs) (7)	AVERAGE REMAINING LIFE (Yrs) (8)	ANNUAL ACCRUAL (9)	ANNUAL ACCRUAL RATE (%) (10)
	INTANGIBLE PLANT									
303.3	Misc. Intangible Plant - Software - Project Enterprise		7-SQ	$621,985	$621,985	$0	0.00	0.50	$0	0.000000%
303.4	Misc. Intangible Plant - Software - Other		7 SQ	29,368,853	$21,000,197	8,368,656	7.78	1.71	3,775,662	12.856009%
303.5	Misc. Intangible Plant - Software - Proj Evolution		7-SQ	8,047,879	$8,047,879	0	0.00	2.50	0	0.000000%
	TOTAL INTANGIBLES			$38,038,717	$29,670,061	$8,368,656	10.07	2.22	$3,775,662	9.925840%
	TRANSMISSION PLANT									
350.2	Land Rights		80-SQ	$26,933,492	$11,441,502	$15,491,990	66.47	38.23	$405,190	1.504409%
352	Structures		58-R3	6,720,252	2,693,030	4,027,222	54.30	32.54	123,769	1.841726%
353	Station Equipment		54-R1.5	182,774,708	55,374,009	127,400,699	59.52	41.49	3,070,849	1.680128%
354	Towers and Fixtures		65-R3	41,082,524	26,614,852	14,467,672	86.22	30.36	476,491	1.159838%
355	Poles and Fixtures		62-R3	46,196,355	17,969,823	28,226,532	68.69	41.97	672,511	1.455766%
356	Overhead Conductors and Devices		65-R2.5	67,409,524	29,417,786	37,991,737	75.49	42.87	892,938	1.324647%
356.1	Clearing Costs and Rights of Way		80-SQ	18,717,197	3,568,785	15,148,411	81.34	65.83	230,101	1.229358%
358	Underground Conductor & Devices		40-R0.5	1,190,918	61,831	1,129,087	39.77	37.71	29,948	2.514658%
359	Roads and Trails		50-SQ	746,971	512,455	234,516	44.43	13.95	16,812	2.250668%
	TOTAL TRANSMISSION PLANT			$391,771,940	$147,654,073	$244,117,867		41.25	$5,918,608	1.510728%
	DISTRIBUTION PLANT									
360.2	Land Rights		65-SQ	$28,932,190	$14,033,111	$14,899,079	67.87	34.95	$426,319	1.473510%
361	Structures		45-R3	12,964,492	5,846,584	7,117,908	41.16	22.60	314,951	2.429338%
362	Station Equipment		58-R2	204,313,884	70,681,179	133,632,706	64.17	41.97	3,184,132	1.558451%
364	Poles, Towers and Fixtures		65-R0.5	346,857,644	103,388,800	243,468,844	75.90	53.28	4,569,721	1.317463%
365	Overhead Conductors and Devices		55-R0.5	365,129,006	73,936,496	291,192,510	58.62	46.75	6,228,298	1.705780%
365.1	Clearing Costs and Rights of Way		65-SQ	129,000,442	16,431,202	112,569,240	65.84	57.45	1,959,429	1.518932%
366	Underground Conduit		60-R2.5	30,284,874	10,716,043	19,568,832	57.61	37.23	525,668	1.735746%
367	Underground Conductors and Devices		35-R3	201,130,561	65,072,092	136,058,469	35.03	23.70	5,740,986	2.854358%
368	Line Transformers		42-S0	391,129,267	123,368,014	267,761,253	46.77	32.02	8,363,185	2.138215%
369	Overhead Services		42-R0.5	70,598,384	17,674,026	52,924,359	43.83	32.86	1,610,845	2.281703%
369.1	Underground Services		41-R2.5	98,458,792	45,960,843	52,497,949	44.75	23.86	2,200,409	2.234853%
370	Meters		24-O2	65,903,176	11,546,051	54,357,126	23.87	19.69	2,761,271	4.189890%
370	Smart Meters		15-O2	1,218,958	29,853	1,189,105	15.00	14.63	81,264	6.666667%
371	Install. On Cust. Premises - Dusk to Dawn Lights		24-O1	3,819,894	1,828,694	1,991,200	31.42	16.38	121,568	3.182488%
371.21	Install. On Cust. Premises - Meter Socket Devices		25-SQ	412,208	298,985	113,223	31.03	8.52	13,284	3.222582%
371.23	Install. On Cust. Premises - Surge Suppression		10-SQ	276,708	276,708	0	0.00	0.00	0	0.000000%
373	Street Lighting and Signal Systems		34-L0	12,229,687	2,777,690	9,451,997	36.06	27.87	339,160	2.773253%
	TOTAL DISTRIBUTION PLANT			$1,962,660,169	$563,866,368	$1,398,793,801	51.06	36.39	$38,440,490	1.958591%

METROPOLITAN EDISON COMPANY

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCURALS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2013

	ACCOUNT AND DESCRIPTION (1)	PROBABLE RETIREMENT YEAR (2)	IOWA SURVIVOR CURVE (3)	GROSS ORIGINAL COST 12/31/2013 (4)	BOOK RESERVE 12/31/2013 (5)	NET ORIGINAL COST 12/31/2013 (6)	AVERAGE SERVICE LIFE (Yrs) (7)	AVERAGE REMAINING LIFE (Yrs) (8)	ANNUAL ACCRUAL (9)	ANNUAL ACCRUAL RATE (%) (10)
	GENERAL PLANT									
389.2	Land Rights		50-SQ	$18,078	$15,106	$2,972	45.22	7.44	$400	2.211293%
390.1	Structures									
	Misc. Improvements - All Other Locations		40-R1.5	18,513,559	7,727,647	10,785,912	45.12	26.29	$410,302	2.216226%
	Corporate Headquarters - Reading	6-2038	80-S0	50,456,453	25,068,765	25,387,688	44.98	22.63	1,121,754	2.223212%
	Lebanon Service Center	6-2023	80-S0	5,087,650	3,071,867	2,015,784	23.28	9.22	218,577	4.296225%
	Easton Service Center	6-2018	80-S0	4,604,359	3,932,329	672,030	30.39	4.44	151,512	3.290611%
	York Service Center	6-2029	80-S0	7,014,294	3,930,985	3,083,309	35.71	15.70	196,425	2.800358%
	Total Account 390.1			$85,676,315	$43,731,593	$41,944,722	40.83	19.99	$2,098,570	2.449417%
390.2	Land Improvements - Land/Yard									
	Misc. Improvements - All Other Locations		25-R1	$4,340,628	$2,794,277	$1,546,351	26.97	9.61	$160,947	3.707923%
	Corporate Headquarters - Reading	6-2038	80-SQ	3,890,764	1,691,536	2,199,228	42.92	24.26	90,647	2.329789%
	Lebanon Service Center	6-2023	80-SQ	1,009,739	787,684	222,055	43.20	9.50	23,374	2.314868%
	Easton Service Center	6-2018	80-SQ	1,369,572	844,055	525,518	11.73	4.50	116,782	8.526875%
	York Service Center	6-2029	80-SQ	1,855,579	1,131,306	724,273	39.51	15.42	46,965	2.531022%
	Total Account 390.2			$12,466,282	$7,248,857	$5,217,425	28.42	11.89	$438,715	3.519210%
391	Office Furniture and Equip. - Furniture		20-SQ	$16,629,980	$14,460,582	$2,169,398	24.25	3.16	$685,871	4.124306%
391.2	Office Furniture and Equip. - Office Machines		10-SQ	5,920,633	5,920,633	0	0.00	0.00	0	0.000000%
391.3	Office Furniture and Equip. - Personal Computers		4-SQ	2,194,188	2,046,685	147,503	14.88	0.84	147,503	6.722435%
391.4	Office Furniture and Equip. - Information Systems		10-SQ	2,314,955	(1,902)	2,316,857	7.67	7.68	301,710	13.033098%
391.4	Office Furniture and Equip. - Data Proc - Smart Meters		5-SQ	713,151	48,222	664,929	5.00	4.66	142,630	20.000000%
392.3	Transportation - Heavy Trucks		10-L3	268,209	72,066	196,143	10.42	7.62	25,747	9.599641%
392.4	Transportation Equipment - Pole Trailers		25-S1	711,525	454,426	257,099	29.19	10.55	24,375	3.425684%
392.5	Transportation Equipment - Van Trailers		25-S1	87,237	78,891	8,345	126.26	12.08	691	0.792040%
393	Stores Equipment		20-SQ	1,411,422	1,396,541	14,880	113.61	1.20	12,424	0.880237%
394	Tools, Shop and Garage Equipment		25-SQ	11,612,991	6,556,388	5,056,603	23.84	10.38	487,027	4.193808%
395	Laboratory Equipment		20-SQ	3,047,684	3,047,652	32	94,696.97	0.85	32	0.001056%
396	Power Operated Equipment		20-L0.5	751,658	612,058	139,600	58.11	10.79	12,935	1.720815%
397	Communication Equipment		20-R0.5	33,964,326	23,670,778	10,293,549	33.19	10.06	1,023,304	3.012878%
398	Miscellaneous Equipment		20-SQ	2,586,561	2,489,985	96,576	54.41	2.03	47,540	1.837968%
	TOTAL GENERAL PLANT			$180,375,195	$111,848,562	$68,526,633	33.10	12.57	$5,449,473	3.021188%
	TOTAL DEPRECIABLE PLANT			$2,572,846,020	$853,039,063	$1,719,806,956			$53,584,233	2.089725%
	TOTAL NONDEPRECIABLE PLANT			$105,081,468	$95,404,733	$9,676,734				
	TOTAL PLANT IN SERVICE			$2,677,927,487	$948,443,797	$1,729,483,691			$53,584,233	

METROPOLITAN EDISON COMPANY

SCHEDULE 2. SUMMARY OF PLANT IN SERVICE ACTIVITY FOR THE YEAR ENDED DECEMBER 31, 2013

	ACCOUNT AND DESCRIPTION (1)	GROSS ORIGINAL COST 1/1/2013 (2)	ADDITIONS (3)	RETIREMENTS (4)	ADJUSTMENTS (A) (5)	GROSS ORIGINAL COST 12/31/2013 (6)	PERCENT OF ORIGINAL COST RETIRED (7)
	INTANGIBLE PLANT						
303.3	Misc. Intangible Plant - Software - Project Enterprise	$621,985				$621,985	0.00
303.4	Misc. Intangible Plant - Software - Other	28,277,678	$1,091,175			29,368,853	0.00
303.5	Misc. Intangible Plant - Software - Proj Evolution	$8,047,879				$8,047,879	0.00
	TOTAL INTANGIBLES	$36,947,542	$1,091,175	$0	$0	$38,038,717	0.00
	TRANSMISSION PLANT						
350.2	Land Rights	$27,169,639	($236,147)			$26,933,492	0.00
352	Structures	7,333,228	431,515		(1,044,491)	6,720,252	0.00
353	Station Equipment	164,542,836	19,049,921	(1,024,713)	$206,664	182,774,708	0.62
354	Towers and Fixtures	41,961,853	(835,615)	(43,714)		41,082,524	0.10
355	Poles and Fixtures	44,969,810	1,703,268	(476,723)		46,196,355	1.06
356	Overhead Conductors and Devices	64,509,072	3,440,023	(539,571)		67,409,524	0.84
356.1	Clearing Costs and Rights of Way	12,357,013	4,966,770		1,393,414	18,717,197	0.00
358	Underground Conductor & Devices	1,022,596	202,282	(33,960)		1,190,918	3.32
359	Roads and Trails	746,971	0			746,971	0.00
	TOTAL TRANSMISSION PLANT	$364,613,016	$28,722,017	($2,118,681)	$555,587	$391,771,940	0.58
	DISTRIBUTION PLANT						
360.2	Land Rights	$28,696,043	$236,147			$28,932,190	0.00
361	Structures	12,751,972	$214,842	($2,322)		12,964,492	0.02
362	Station Equipment	195,318,146	9,727,797	(1,504,662)	772,603	204,313,884	0.77
364	Poles, Towers and Fixtures	384,863,141	(36,019,634)	(1,985,862)		346,857,644	0.52
365	Overhead Conductors and Devices	320,548,861	50,244,807	(5,664,661)		365,129,006	1.77
365.1	Clearing Costs and Rights of Way	118,923,762	10,425,602		(348,923)	129,000,442	0.00
366	Underground Conduit	30,197,493	87,175	206		30,284,874	0.00
367	Underground Conductors and Devices	188,760,229	13,993,952	(1,623,619)		201,130,561	0.86
368	Line Transformers	386,474,625	8,886,557	(4,231,916)		391,129,267	1.10
369	Overhead Services	68,127,640	2,531,698	(60,954)		70,598,384	0.09
369.1	Underground Services	98,458,792				98,458,792	0.00
370	Meters	66,553,985	4,125,592	(4,832,820)	56,420	65,903,176	7.26
370	Smart Meters	0	1,277,620	(2,243)	(56,420)	1,218,958	#DIV/0!
371	Install. On Cust. Premises - Dusk to Dawn Lights	3,722,598	123,969	(26,673)		3,819,894	0.72
371.2	Install. On Cust. Premises - Meter Socket Devices	412,208			0	412,208	0.00
371.23	Install. On Cust. Premises - Surge Suppression	276,708			0	276,708	0.00
373	Street Lighting and Signal Systems	11,461,900	1,434,443	(666,655)		12,229,687	5.82
	TOTAL DISTRIBUTION PLANT	$1,915,548,104	$67,290,567	($20,602,182)	$423,680	$1,962,660,169	1.08

METROPOLITAN EDISON COMPANY

SCHEDULE 2. SUMMARY OF PLANT IN SERVICE ACTIVITY FOR THE YEAR ENDED DECEMBER 31, 2013

	ACCOUNT AND DESCRIPTION (1)	GROSS ORIGINAL COST 1/1/2013 (2)	ADDITIONS (3)	RETIREMENTS (4)	ADJUSTMENTS (A) (5)	GROSS ORIGINAL COST 12/31/2013 (6)	PERCENT OF ORIGINAL COST RETIRED (7)
	GENERAL PLANT						
389	Land Rights	$18,078				$18,078	0.00
390.1	Structures						
	Misc. Improvements - All Other Locations	$17,547,613	$770,751		$195,195	$18,513,559	0.00
	Corporate Headquarters - Reading	48,853,401	1,603,052			50,456,453	0.00
	Lebanon Service Center	4,777,903	414,613	(104,866)		5,087,650	2.19
	Easton Service Center	5,726,156	(1,043,059)	(78,737)		4,604,359	1.38
	York Service Center	7,011,955	2,339			7,014,294	0.00
	Total Account 390.1	$83,917,027	$1,747,695	($183,603)	$195,195	$85,676,315	0.22
390.2	Land Improvements - Land/Yard						
	Misc. Improvements - All Other Locations	$4,340,628				$4,340,628	0.00
	Corporate Headquarters - Reading	3,890,764				3,890,764	0.00
	Lebanon Service Center	1,009,739				1,009,739	0.00
	Easton Service Center	1,369,572				1,369,572	0.00
	York Service Center	1,855,579				1,855,579	0.00
	Total Account 390.2	$12,466,282	$0	$0	$0	$12,466,282	0.00
391	Office Furniture and Equip. - Furniture	$17,100,405	$51,119	($521,544)		$16,629,980	3.05
391.2	Office Furniture and Equip. - Office Machines	5,920,633				5,920,633	0.00
391.3	Office Furniture and Equip. - Personal Computers	2,365,809	428,903	(460,109)	(140,416)	2,194,188	19.45
391.4	Office Furniture and Equip - Information Systems	350	2,422,715	(351)	(107,758)	2,314,955	100.43
391.4	Office Furniture and Equip - Data Proc - Smart Meter	0	464,977		248,174	713,151	#DIV/0!
392	Transportation Equipment -Heavy Trucks	419,787	(107,927)		(43,650)	268,209	0.00
392.4	Transportation Equipment -Pole Trailers	711,525				711,525	0.00
392.5	Transportation Equipment - Van Trailers	87,237				87,237	0.00
393	Stores Equipment	1,428,705		(17,284)		1,411,422	1.21
394	Tools, Shop and Garage Equipment	10,173,126	1,755,351	(315,486)		11,612,991	3.10
395	Laboratory Equipment	3,130,477		(82,793)		3,047,684	2.64
396	Power Operated Equipment	642,814	108,844			751,658	0.00
397	Communication Equipment	34,970,177	1,062,335	(2,068,186)		33,964,326	5.91
398	Miscellaneous Equipment	2,671,048	11,519	(96,006)		2,586,561	3.59
	TOTAL GENERAL PLANT	$176,023,480	$7,945,531	($3,745,361)	$151,545	$180,375,195	2.13
	TOTAL DEPRECIABLE PLANT	$2,493,132,142	$105,049,290	($26,466,224)	$1,130,812	$2,572,846,020	1.06
	NONDEPRECIABLE PLANT AND ASSET RETIREMENT COSTS						
301	Organization	$123,507				$123,507	
302	Franchise and Consents	165,169				165,169	
326	Asset Retirement Costs TMI #2	95,321,155				95,321,155	
350.1	Land	3,429,373				3,429,373	
359	Asset Retirement Costs Transmission Subs	4,666				4,666	
360.1	Land	3,080,352	$124,524			3,204,876	
374	Asset Retirement Costs Distribution Subs	37,210				37,210	
389.1	Land	1,567,850	1,104,958			2,672,808	
39030	Building Leaseholds	16,754				16,754	
399	Asset Retirement Costs General Buildings	105,951				105,951	
	TOTAL NONDEPRECIABLE PLANT	$103,851,986	$1,229,482	$0	$0	$105,081,468	
	TOTAL PLANT IN SERVICE	$2,596,984,127	$106,278,772	($26,466,224)	$1,130,812	$2,677,927,487	

METROPOLITAN EDISON COMPANY

SCHEDULE 3. SUMMARY OF BOOK RESERVE ACTIVITY FOR THE YEAR ENDED DECEMBER 31, 2013

	ACCOUNT AND DESCRIPTION (1)	BOOK RESERVE 1/1/2013 (2)	ACCRUALS (3)	RETIREMENTS (4)	GROSS SALVAGE (A) (5)	COST OF REMOVAL (A) (6)	TRANSFERS (7)	ADJUSTMENTS (8)	BOOK RESERVE 12/31/2013 (9)	BOOK RESERVE AS A PERCENT OF ORIGINAL COST (10)
	INTANGIBLE PLANT									
303.3	Project Enterprise	($621,985)							($621,985)	
303.4	Misc. Intangible Plant - Software - Other	(17,952,598)	($3,047,599)						(21,000,197)	
303.5	Software Evolution	(8,047,879)							(8,047,879)	
	TOTAL INTANGIBLES	($26,622,462)	($3,047,599)	$0	$0	$0	$0	$0	($29,670,061)	78.00
	TRANSMISSION PLANT									
350.2	Land Rights	($11,035,441)	($406,061)						($11,441,502)	42.48
352	Structures	(2,631,288)	(128,649)				66,907		(2,693,030)	40.07
353	Station Equipment	(53,610,958)	(2,821,080)	1,024,713	(56)	46,569	($13,198)		(55,374,009)	30.30
354	Towers and Fixtures	(26,166,835)	(491,730)	43,714					(26,614,852)	64.78
355	Poles and Fixtures	(17,799,863)	(646,682)	476,723					(17,969,823)	38.90
356	Overhead Conductors and Devices	(29,106,937)	(1,763,836)	539,571		847,681	65,734		(29,417,786)	43.64
356.1	Clearing Costs and Rights of Way	(3,283,574)	(193,832)				(91,379)		(3,568,785)	19.07
358	Underground Conductor & Devices	(69,006)	(26,785)	33,960					(61,831)	5.19
359	Roads and Trails	(495,639)	(16,816)						(512,455)	68.60
	TOTAL TRANSMISSION PLANT	($144,199,541)	($6,495,471)	$2,118,681	($56)	$894,250	$28,064	$0	($147,654,073)	37.69
	DISTRIBUTION PLANT									
360.2	Land Rights	($13,608,983)	($424,128)						($14,033,111)	48.50
361	Structures	(5,532,139)	(316,767)	$2,322					(5,846,584)	45.10
362	Station Equipment	(68,910,966)	(3,804,297)	1,504,662	(9,862)	922,750	($383,465)		(70,681,179)	34.59
364	Poles, Towers and Fixtures	(100,588,313)	(4,786,349)	1,985,862					(103,388,800)	29.81
365	Overhead Conductors and Devices	(73,760,314)	(6,650,851)	5,664,661	(577)	1,322,164	(511,581)		(73,936,496)	20.25
365.1	Clearing Costs and Rights of Way	(14,565,026)	(1,890,648)				24,472		(16,431,202)	12.74
366	Underground Conduit	(10,187,435)	(528,402)	(205)					(10,716,043)	35.38
367	Underground Conductors and Devices	(61,146,542)	(5,549,169)	1,623,619					(65,072,092)	32.35
368	Line Transformers	(119,308,500)	(8,594,280)	4,231,916	(457,395.66)	861,112	(136,121)	35,255	(123,368,014)	31.54
369	Overhead Services	(16,135,399)	(1,799,139)	60,954		221,294	(21,736)		(17,674,026)	25.03
369.1	Underground Services	(43,740,985)	(2,219,858)						(45,960,843)	46.68
370	Meters	(13,727,848)	(2,649,743)	4,832,820			(1,279)		(11,546,051)	17.52
370	Smart Meters	0	(33,375)	2,243			1,279		(29,853)	2.45
371	Install. On Cust. Premises - Dusk to Dawn Lights	(1,733,319)	(122,047)	26,672			0		(1,828,694)	47.87
371.2	Install. On Cust. Premises - Meter Socket Devices	(285,701)	(13,284)						(298,985)	72.53
371.23	Install. On Cust. Premises - Surge Suppression	(276,708)							(276,708)	100.00
373	Street Lighting and Signal Systems	(3,131,073)	66,828	666,654		(377,183)	(2,917)		(2,777,690)	22.71
	TOTAL DISTRIBUTION PLANT	($546,639,251)	($39,315,509)	$20,602,181	($467,835)	$2,950,138	($1,031,347)	$35,255	($563,866,368)	28.73

METROPOLITAN EDISON COMPANY

SCHEDULE 3. SUMMARY OF BOOK RESERVE ACTIVITY FOR THE YEAR ENDED DECEMBER 31, 2013

	ACCOUNT AND DESCRIPTION (1)	BOOK RESERVE 1/1/2013 (2)	ACCRUALS (3)	RETIREMENTS (4)	GROSS SALVAGE (A) (5)	COST OF REMOVAL (A) (6)	TRANSFERS (7)	ADJUSTMENTS (8)	BOOK RESERVE 12/31/2013 (9)	BOOK RESERVE AS A PERCENT OF ORIGINAL COST (10)
	GENERAL PLANT									
389	Land Rights	($14,699)	($407)						($15,106)	83.56
390.1	Structures									
	Misc. Improvements - All Other Locations	($7,334,126)	($498,729)			$118,631	($13,423)		($7,727,647)	41.74
	Corporate Headquarters - Reading	(23,984,249)	(1,084,516)						(25,068,765)	49.68
	Lebanon Service Center	(2,990,485)	(186,248)	104,866					(3,071,867)	60.38
	Easton Service Center	(3,671,401)	(339,664)	78,737					(3,932,329)	85.40
	York Service Center	(3,721,294)	(209,691)						(3,930,985)	56.04
	Total Account 390.1	($41,701,556)	($2,318,848)	$183,603	$0	$118,631	($13,423)	$0	($43,731,593)	51.04
390.2	Land Improvements - Land/Yard									
	Misc. Improvements - All Other Locations	($2,624,417)	($169,861)						($2,794,277)	64.37
	Corporate Headquarters - Reading	(1,600,889)	(90,647)						(1,691,536)	43.48
	Lebanon Service Center	(764,310)	(23,374)						(787,684)	78.01
	Easton Service Center	(727,273)	(116,782)						(844,055)	61.63
	York Service Center	(1,084,537)	(46,769)						(1,131,306)	60.97
	Total Account 390.2	($6,801,425)	($447,432)	$0	$0	$0	$0	$0	($7,248,857)	58.15
391	Office Furniture and Equip. - Furniture	($14,228,375)	($753,751)	$521,544					($14,460,582)	86.95
391.2	Office Furniture and Equip. - Office Machines	(5,920,633)							(5,920,633)	100.00
391.3	Office Furniture and Equip. - Personal Computers	(1,860,218)	(659,074)	460,109			12,498		(2,046,685)	93.28
391.4	Office Furniture and Equip. - Information Systems	(225)	262	351			1,513		1,902	-0.08
391.4	Office Furniture and Equip. - Data Proc Smart Meters	0	(34,210)				(14,012)		(48,222)	17.98
392	Transportation Equipment - Heavy Trucks	(40,187)	(38,884)				7,004		(72,066)	26.87
392.4	Transportation Equipment - Pole Trailers	(428,872)	(25,554)						(454,426)	63.87
392.5	Transportation Equipment - Van Trailers	(78,174)	(717)						(78,891)	90.43
393	Stores Equipment	(1,382,946)	(30,879)	17,284					(1,396,541)	98.95
394	Tools, Shop and Garage Equipment	(6,379,610)	(492,264)	315,486					(6,556,388)	56.46
395	Laboratory Equipment	(3,129,864)	(581)	82,793					(3,047,652)	100.00
396	Power Operated Equipment	(608,161)	(3,897)						(612,058)	81.43
397	Communication Equipment	(24,755,167)	(987,927)	2,068,186		$4,130			(23,670,778)	69.69
398	Miscellaneous Equipment	(2,523,068)	(62,923)	96,006					(2,489,985)	96.27
	TOTAL GENERAL PLANT	($109,853,181)	($5,857,085)	$3,745,361	$0	$122,762	($6,418)	$0	($111,848,562)	62.01
	TOTAL DEPRECIABLE PLANT	($827,314,434)	($54,715,664)	$26,466,222	($467,891)	$3,967,150	($1,009,702)	$35,255	($853,039,063)	33.16
	NONDEPRECIABLE PLANT AND ASSET RETIREMENT COSTS									
326	Asset Retirement Costs TMI # 2	($95,321,155)							($95,321,155)	
350.1	Land	($7,848)	$1,500			(1,500)			($7,848)	
359.1	Asset Retirement Costs Transmission Subs	(2,486)	($104)						(2,589)	
374	Asset Retirement Costs Distribution Subs	(20,482)	(759)						(21,241)	
360	Land Sale Adjustment	(0)							(0)	
39030	Building Leaseholds	(3,246)	(838)						(4,084)	
399	Asset Retirement Costs General Buildings	(45,950)	(1,866)						(47,816)	
	TOTAL NONDEPRECIABLE PLANT	($95,401,167)	($2,067)	$0	$0	($1,500)	$0	$0	($95,404,733)	
	TOTAL BOOK RESERVE	($922,715,601)	($54,717,730)	$26,466,222	($467,891)	$3,965,650	($1,009,702)	$35,255	($948,443,797)	

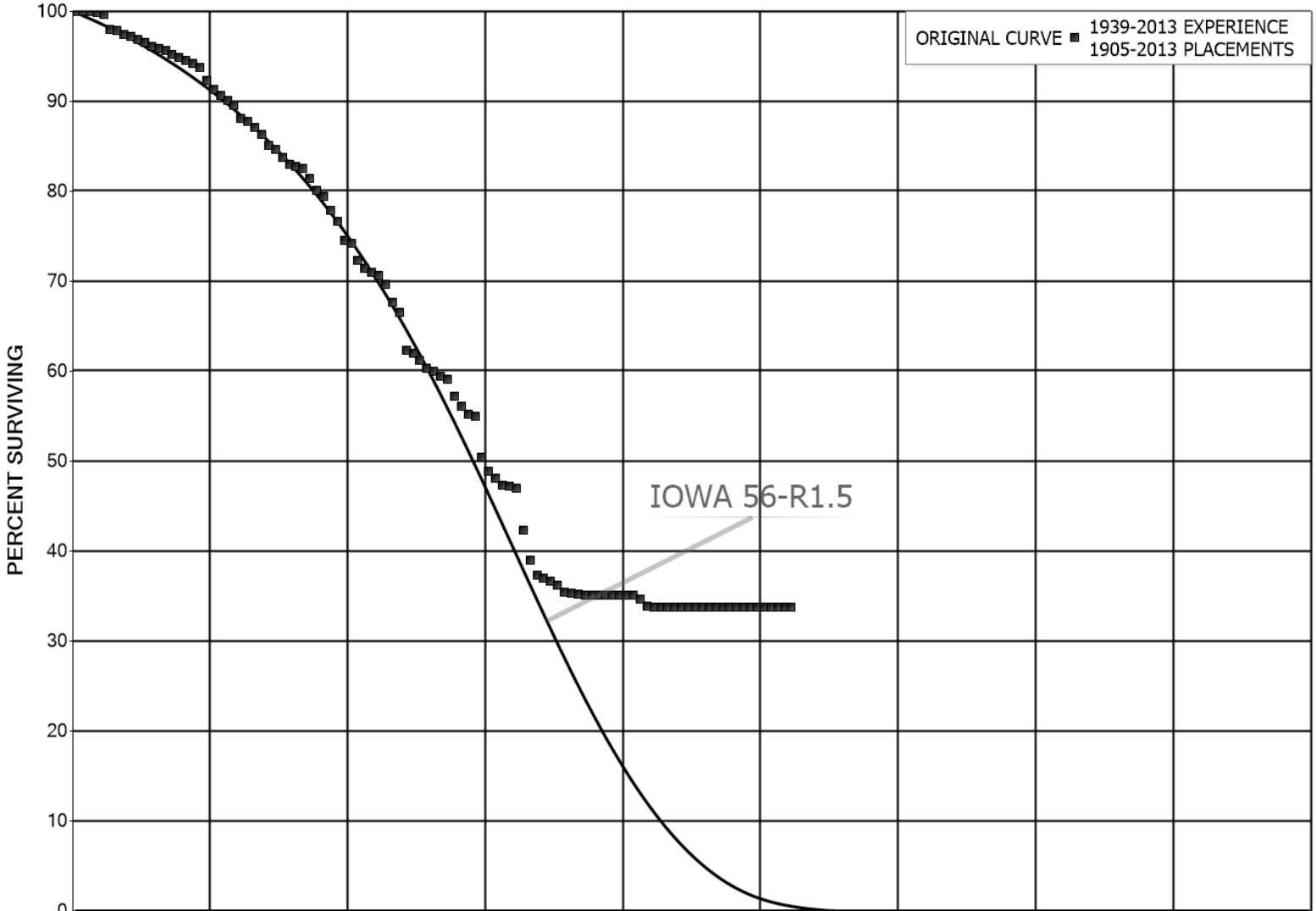
(A) Cost of Removal and Salvage amounts are expensed as incurred and as such are not included in this summarization.

METROPOLITAN EDISON COMPANY

SCHEDULE 4. EXPERIENCED COST OF REMOVAL AND SALVAGE AMOUNTS FOR THE YEARS 2009-2013 RECORDED TO ACCOUNT 403, DEPRECIATION EXPENSE

	COST OF REMOVAL 403 (1)	SALVAGE 403 (2)	NET SALVAGE (3)=(1)+(2)
2009	$4,955,233	($1,175,586)	$3,779,647
2010	$4,369,607	($696,543)	$3,673,065
2011	$19,958,473	($6,484,916)	$13,473,557
2012	$23,007,411	($498,217)	$22,509,194
2013	$4,912,392	($467,891)	$4,444,501
Total	$57,203,117	($9,323,153)	$47,879,964
5-Year Average	$11,440,623	($1,864,631)	$9,575,993

METROPOLITAN EDISON COMPANY
ACCOUNT 353 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



METROPOLITAN EDISON COMPANY

ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1905-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	229,958,021	16,736	0.0001	0.9999	100.00
0.5	212,512,592	80,270	0.0004	0.9996	99.99
1.5	201,331,267	51,183	0.0003	0.9997	99.95
2.5	189,513,646	140,361	0.0007	0.9993	99.93
3.5	183,618,669	449,655	0.0024	0.9976	99.86
4.5	173,851,003	2,823,301	0.0162	0.9838	99.61
5.5	148,202,373	157,089	0.0011	0.9989	97.99
6.5	146,342,820	785,145	0.0054	0.9946	97.89
7.5	128,851,813	311,876	0.0024	0.9976	97.36
8.5	125,748,187	373,677	0.0030	0.9970	97.13
9.5	122,005,802	471,637	0.0039	0.9961	96.84
10.5	119,968,722	442,938	0.0037	0.9963	96.47
11.5	117,937,198	295,890	0.0025	0.9975	96.11
12.5	115,392,244	298,565	0.0026	0.9974	95.87
13.5	110,707,059	483,507	0.0044	0.9956	95.62
14.5	109,460,105	407,458	0.0037	0.9963	95.20
15.5	106,737,439	416,829	0.0039	0.9961	94.85
16.5	103,004,926	296,769	0.0029	0.9971	94.48
17.5	100,365,769	551,645	0.0055	0.9945	94.21
18.5	97,353,903	1,452,843	0.0149	0.9851	93.69
19.5	90,398,151	1,020,622	0.0113	0.9887	92.29
20.5	87,817,470	600,334	0.0068	0.9932	91.25
21.5	81,401,101	498,451	0.0061	0.9939	90.62
22.5	77,211,739	488,281	0.0063	0.9937	90.07
23.5	75,670,947	1,238,807	0.0164	0.9836	89.50
24.5	72,533,496	226,039	0.0031	0.9969	88.03
25.5	71,131,861	528,658	0.0074	0.9926	87.76
26.5	68,583,095	634,762	0.0093	0.9907	87.11
27.5	61,243,908	861,429	0.0141	0.9859	86.30
28.5	56,210,385	348,174	0.0062	0.9938	85.09

METROPOLITAN EDISON COMPANY

ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
29.5	54,214,275	522,021	0.0096	0.9904	84.56
30.5	51,403,868	464,608	0.0090	0.9910	83.75
31.5	50,575,354	153,382	0.0030	0.9970	82.99
32.5	49,940,950	119,404	0.0024	0.9976	82.74
33.5	49,574,625	707,762	0.0143	0.9857	82.54
34.5	48,665,520	766,416	0.0157	0.9843	81.36
35.5	47,506,217	388,910	0.0082	0.9918	80.08
36.5	46,222,147	910,067	0.0197	0.9803	79.42
37.5	33,960,887	531,204	0.0156	0.9844	77.86
38.5	31,753,263	906,530	0.0285	0.9715	76.64
39.5	30,240,804	119,991	0.0040	0.9960	74.45
40.5	27,606,763	714,747	0.0259	0.9741	74.16
41.5	24,586,641	297,338	0.0121	0.9879	72.24
42.5	20,973,636	128,746	0.0061	0.9939	71.37
43.5	16,466,236	67,753	0.0041	0.9959	70.93
44.5	14,140,187	202,893	0.0143	0.9857	70.64
45.5	12,186,004	348,316	0.0286	0.9714	69.62
46.5	11,445,021	191,550	0.0167	0.9833	67.63
47.5	10,474,692	661,634	0.0632	0.9368	66.50
48.5	9,359,859	46,799	0.0050	0.9950	62.30
49.5	9,036,250	113,606	0.0126	0.9874	61.99
50.5	7,860,235	117,543	0.0150	0.9850	61.21
51.5	6,590,126	39,746	0.0060	0.9940	60.29
52.5	6,395,076	57,161	0.0089	0.9911	59.93
53.5	6,273,557	31,506	0.0050	0.9950	59.39
54.5	6,102,197	202,446	0.0332	0.9668	59.10
55.5	5,505,458	107,405	0.0195	0.9805	57.14
56.5	5,284,186	77,737	0.0147	0.9853	56.02
57.5	5,175,139	18,965	0.0037	0.9963	55.20
58.5	4,803,211	399,993	0.0833	0.9167	54.99

METROPOLITAN EDISON COMPANY

ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
59.5	1,930,806	60,615	0.0314	0.9686	50.41
60.5	1,771,081	27,430	0.0155	0.9845	48.83
61.5	1,219,040	20,309	0.0167	0.9833	48.08
62.5	1,015,399	2,664	0.0026	0.9974	47.27
63.5	985,858	2,953	0.0030	0.9970	47.15
64.5	966,200	96,120	0.0995	0.9005	47.01
65.5	651,573	51,620	0.0792	0.9208	42.33
66.5	510,800	21,693	0.0425	0.9575	38.98
67.5	480,980	5,052	0.0105	0.9895	37.32
68.5	459,794	4,396	0.0096	0.9904	36.93
69.5	431,756	5,332	0.0123	0.9877	36.58
70.5	249,976	5,100	0.0204	0.9796	36.13
71.5	226,342	365	0.0016	0.9984	35.39
72.5	114,277	673	0.0059	0.9941	35.33
73.5	98,918	91	0.0009	0.9991	35.12
74.5	97,438		0.0000	1.0000	35.09
75.5	97,199		0.0000	1.0000	35.09
76.5	97,189		0.0000	1.0000	35.09
77.5	96,769	115	0.0012	0.9988	35.09
78.5	96,057		0.0000	1.0000	35.05
79.5	96,057	54	0.0006	0.9994	35.05
80.5	96,003		0.0000	1.0000	35.03
81.5	95,969	1,156	0.0120	0.9880	35.03
82.5	92,814	2,017	0.0217	0.9783	34.61
83.5	82,975	293	0.0035	0.9965	33.86
84.5	69,679		0.0000	1.0000	33.74
85.5	68,623		0.0000	1.0000	33.74
86.5	53,277		0.0000	1.0000	33.74
87.5	39,864		0.0000	1.0000	33.74
88.5	8,321		0.0000	1.0000	33.74

METROPOLITAN EDISON COMPANY

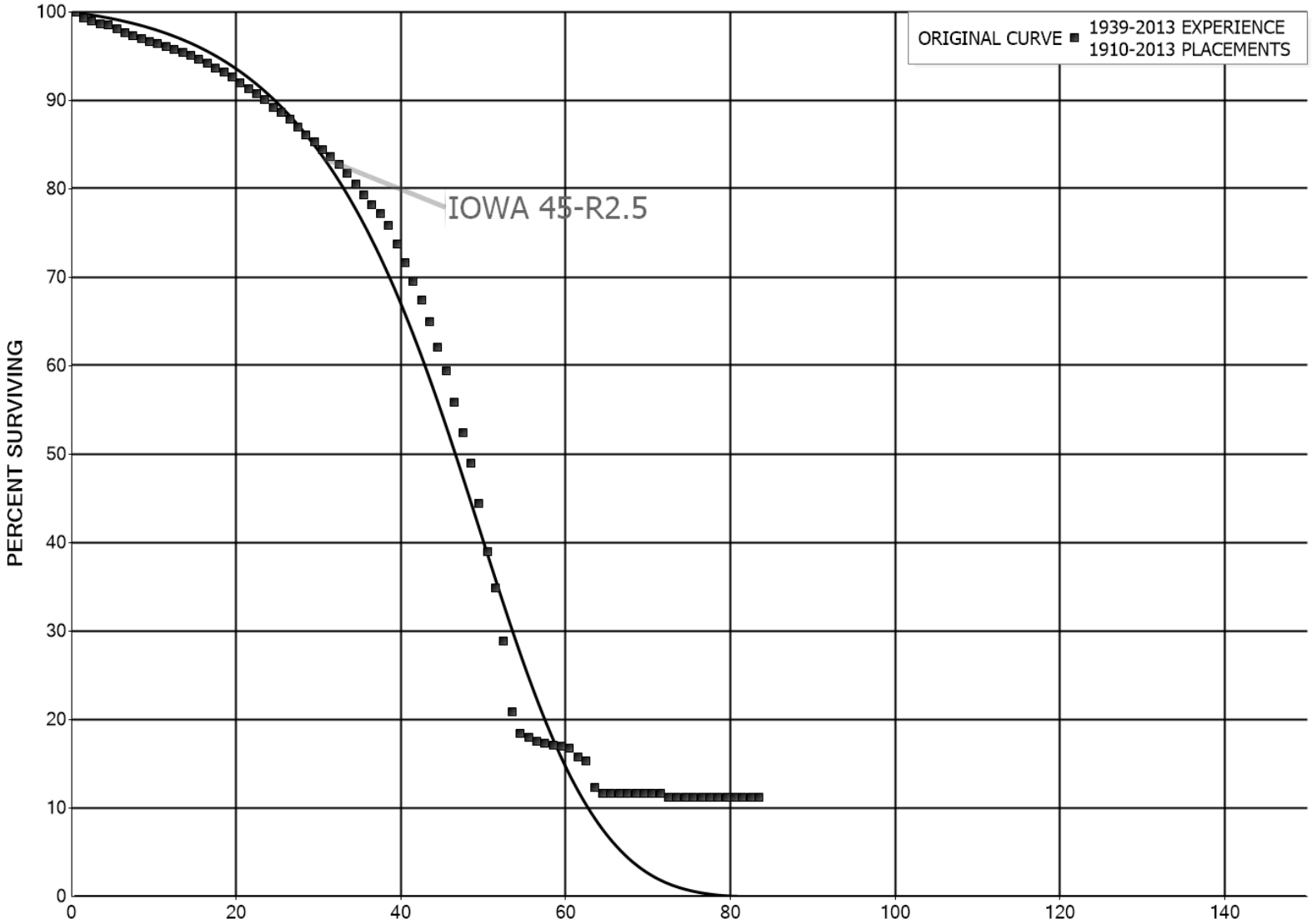
ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
89.5	8,304		0.0000	1.0000	33.74
90.5	2,978		0.0000	1.0000	33.74
91.5	2,848		0.0000	1.0000	33.74
92.5	2,773		0.0000	1.0000	33.74
93.5	312		0.0000	1.0000	33.74
94.5	49		0.0000	1.0000	33.74
95.5	49		0.0000	1.0000	33.74
96.5	49		0.0000	1.0000	33.74
97.5	49		0.0000	1.0000	33.74
98.5	49		0.0000	1.0000	33.74
99.5	49		0.0000	1.0000	33.74
100.5	49		0.0000	1.0000	33.74
101.5	49		0.0000	1.0000	33.74
102.5	49		0.0000	1.0000	33.74
103.5	49		0.0000	1.0000	33.74
104.5					33.74

METROPOLITAN EDISON COMPANY
ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



METROPOLITAN EDISON COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	205,016,324	195,304	0.0010	0.9990	100.00
0.5	192,977,926	1,193,713	0.0062	0.9938	99.90
1.5	178,851,546	681,225	0.0038	0.9962	99.29
2.5	167,690,619	439,734	0.0026	0.9974	98.91
3.5	160,133,209	307,148	0.0019	0.9981	98.65
4.5	146,490,409	555,111	0.0038	0.9962	98.46
5.5	143,260,951	694,780	0.0048	0.9952	98.09
6.5	137,793,116	443,918	0.0032	0.9968	97.61
7.5	124,504,003	422,424	0.0034	0.9966	97.30
8.5	116,292,616	378,941	0.0033	0.9967	96.97
9.5	108,637,376	333,424	0.0031	0.9969	96.65
10.5	103,076,274	361,375	0.0035	0.9965	96.35
11.5	98,941,153	304,678	0.0031	0.9969	96.02
12.5	94,197,532	345,863	0.0037	0.9963	95.72
13.5	89,307,893	318,868	0.0036	0.9964	95.37
14.5	84,408,707	362,879	0.0043	0.9957	95.03
15.5	76,189,011	373,908	0.0049	0.9951	94.62
16.5	71,109,032	383,605	0.0054	0.9946	94.16
17.5	68,262,876	328,793	0.0048	0.9952	93.65
18.5	63,339,069	389,148	0.0061	0.9939	93.20
19.5	57,756,321	394,526	0.0068	0.9932	92.62
20.5	53,276,499	396,957	0.0075	0.9925	91.99
21.5	48,068,716	298,886	0.0062	0.9938	91.31
22.5	40,909,493	287,558	0.0070	0.9930	90.74
23.5	34,502,079	348,246	0.0101	0.9899	90.10
24.5	29,572,302	205,874	0.0070	0.9930	89.19
25.5	25,518,266	205,951	0.0081	0.9919	88.57
26.5	21,877,033	226,679	0.0104	0.9896	87.86
27.5	18,737,346	189,642	0.0101	0.9899	86.94
28.5	16,236,958	150,625	0.0093	0.9907	86.06

METROPOLITAN EDISON COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
29.5	14,882,788	153,620	0.0103	0.9897	85.27
30.5	13,789,435	120,454	0.0087	0.9913	84.39
31.5	12,873,055	144,524	0.0112	0.9888	83.65
32.5	12,001,339	145,023	0.0121	0.9879	82.71
33.5	11,056,784	159,870	0.0145	0.9855	81.71
34.5	9,979,775	156,232	0.0157	0.9843	80.53
35.5	9,062,487	118,771	0.0131	0.9869	79.27
36.5	8,171,443	112,542	0.0138	0.9862	78.23
37.5	7,463,253	126,553	0.0170	0.9830	77.15
38.5	6,828,882	195,586	0.0286	0.9714	75.84
39.5	5,724,962	158,376	0.0277	0.9723	73.67
40.5	4,742,999	144,013	0.0304	0.9696	71.63
41.5	4,002,160	118,347	0.0296	0.9704	69.46
42.5	3,263,232	117,021	0.0359	0.9641	67.40
43.5	2,849,663	128,322	0.0450	0.9550	64.99
44.5	2,503,187	109,396	0.0437	0.9563	62.06
45.5	2,152,292	126,509	0.0588	0.9412	59.35
46.5	1,804,190	110,348	0.0612	0.9388	55.86
47.5	1,600,435	107,787	0.0673	0.9327	52.44
48.5	1,389,741	128,769	0.0927	0.9073	48.91
49.5	1,233,864	150,636	0.1221	0.8779	44.38
50.5	1,082,389	113,705	0.1051	0.8949	38.96
51.5	968,378	168,301	0.1738	0.8262	34.87
52.5	800,077	220,645	0.2758	0.7242	28.81
53.5	579,128	67,460	0.1165	0.8835	20.86
54.5	507,611	13,611	0.0268	0.9732	18.43
55.5	619,497	16,823	0.0272	0.9728	17.94
56.5	765,738	7,438	0.0097	0.9903	17.45
57.5	733,192	8,394	0.0114	0.9886	17.28
58.5	714,091	4,510	0.0063	0.9937	17.08

METROPOLITAN EDISON COMPANY

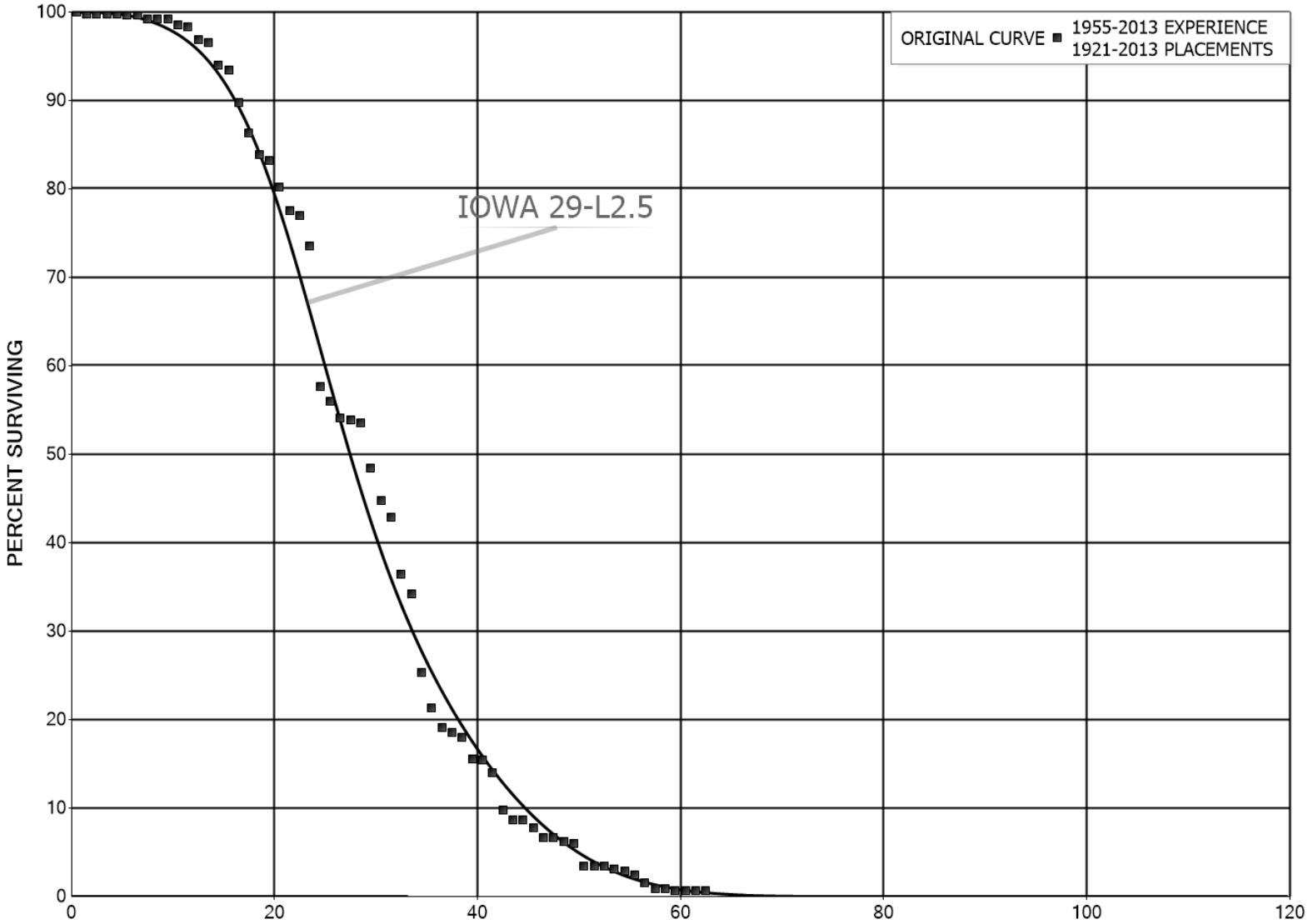
ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
59.5	707,296	9,210	0.0130	0.9870	16.98
60.5	690,463	42,540	0.0616	0.9384	16.76
61.5	528,172	15,760	0.0298	0.9702	15.72
62.5	442,870	85,038	0.1920	0.8080	15.25
63.5	296,105	17,386	0.0587	0.9413	12.33
64.5	219,858	317	0.0014	0.9986	11.60
65.5	204,848	215	0.0010	0.9990	11.58
66.5	191,822	4	0.0000	1.0000	11.57
67.5	165,050	95	0.0006	0.9994	11.57
68.5	16,994		0.0000	1.0000	11.57
69.5	10,210		0.0000	1.0000	11.57
70.5	6,584		0.0000	1.0000	11.57
71.5	6,584	235	0.0357	0.9643	11.57
72.5	6,584		0.0000	1.0000	11.15
73.5	6,572		0.0000	1.0000	11.15
74.5	6,572		0.0000	1.0000	11.15
75.5	6,572		0.0000	1.0000	11.15
76.5	6,090		0.0000	1.0000	11.15
77.5	6,090		0.0000	1.0000	11.15
78.5	6,090		0.0000	1.0000	11.15
79.5	6,090		0.0000	1.0000	11.15
80.5	6,090		0.0000	1.0000	11.15
81.5	6,090		0.0000	1.0000	11.15
82.5	6,090		0.0000	1.0000	11.15
83.5					11.15

METROPOLITAN EDISON COMPANY
ACCOUNT 392.40 TRANSPORTATION EQUIPMENT - POLE TRAILERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



METROPOLITAN EDISON COMPANY

ACCOUNT 392.40 TRANSPORTATION EQUIPMENT - POLE TRAILERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1921-2013 EXPERIENCE BAND 1955-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,210,415		0.0000	1.0000	100.00
0.5	1,113,404	2,700	0.0024	0.9976	100.00
1.5	1,110,707		0.0000	1.0000	99.76
2.5	960,416	223	0.0002	0.9998	99.76
3.5	959,906		0.0000	1.0000	99.73
4.5	950,689	1,123	0.0012	0.9988	99.73
5.5	1,161,671		0.0000	1.0000	99.62
6.5	1,156,701	5,318	0.0046	0.9954	99.62
7.5	1,159,378		0.0000	1.0000	99.16
8.5	1,154,804		0.0000	1.0000	99.16
9.5	1,108,837	7,297	0.0066	0.9934	99.16
10.5	1,140,222	2,779	0.0024	0.9976	98.51
11.5	1,078,690	15,447	0.0143	0.9857	98.27
12.5	1,061,366	3,575	0.0034	0.9966	96.86
13.5	1,048,980	28,402	0.0271	0.9729	96.53
14.5	929,128	4,689	0.0050	0.9950	93.92
15.5	875,121	34,628	0.0396	0.9604	93.44
16.5	621,665	24,006	0.0386	0.9614	89.75
17.5	595,106	16,632	0.0279	0.9721	86.28
18.5	585,884	5,035	0.0086	0.9914	83.87
19.5	507,396	18,231	0.0359	0.9641	83.15
20.5	468,853	15,324	0.0327	0.9673	80.16
21.5	369,994	2,934	0.0079	0.9921	77.54
22.5	367,059	16,290	0.0444	0.9556	76.93
23.5	351,574	76,094	0.2164	0.7836	73.51
24.5	275,480	8,145	0.0296	0.9704	57.60
25.5	263,461	8,877	0.0337	0.9663	55.90
26.5	234,229	812	0.0035	0.9965	54.02
27.5	235,821	1,298	0.0055	0.9945	53.83
28.5	230,922	22,217	0.0962	0.9038	53.53

METROPOLITAN EDISON COMPANY

ACCOUNT 392.40 TRANSPORTATION EQUIPMENT - POLE TRAILERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1921-2013 EXPERIENCE BAND 1955-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
29.5	196,617	14,826	0.0754	0.9246	48.38
30.5	165,855	6,959	0.0420	0.9580	44.73
31.5	153,517	23,161	0.1509	0.8491	42.86
32.5	131,354	7,865	0.0599	0.9401	36.39
33.5	123,489	32,275	0.2614	0.7386	34.21
34.5	86,891	13,828	0.1591	0.8409	25.27
35.5	73,063	7,540	0.1032	0.8968	21.25
36.5	65,307	1,751	0.0268	0.9732	19.06
37.5	63,683	2,094	0.0329	0.9671	18.54
38.5	59,050	7,872	0.1333	0.8667	17.94
39.5	51,179	418	0.0082	0.9918	15.54
40.5	50,760	4,685	0.0923	0.9077	15.42
41.5	41,035	12,450	0.3034	0.6966	13.99
42.5	25,541	2,976	0.1165	0.8835	9.75
43.5	15,629		0.0000	1.0000	8.61
44.5	15,629	1,552	0.0993	0.9007	8.61
45.5	11,019	1,631	0.1480	0.8520	7.76
46.5	9,388		0.0000	1.0000	6.61
47.5	9,388	591	0.0630	0.9370	6.61
48.5	8,796	403	0.0458	0.9542	6.19
49.5	8,393	3,511	0.4183	0.5817	5.91
50.5	4,883		0.0000	1.0000	3.44
51.5	5,229		0.0000	1.0000	3.44
52.5	5,229	593	0.1134	0.8866	3.44
53.5	4,636	381	0.0821	0.9179	3.05
54.5	4,256	592	0.1391	0.8609	2.80
55.5	3,664	1,448	0.3951	0.6049	2.41
56.5	2,216	994	0.4486	0.5514	1.46
57.5	1,222		0.0000	1.0000	0.80
58.5	1,222	347	0.2837	0.7163	0.80
59.5	875		0.0000	1.0000	0.58
60.5	875		0.0000	1.0000	0.58
61.5	875		0.0000	1.0000	0.58
62.5					0.58

Remaining Life Depreciation Accrual

Account: MTED-101/6-303
Scenario: Met Ed 2014 ADR Intangible
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$38,038,716.98	1.71	$4,890,260.79	12.856009%	58.435449%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($6,556,772.60)	0.50	($468,340.90)	7.142857%	
Total:	$38,038,716.98 *		$4,421,919.89	11.624787%	52.839079%
Average:	$34,760,330.68		$4,421,919.89	12.721168%	86.870079%
Grand Total:	$38,038,716.98 *		$4,421,919.89	11.624787%	52.839079%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED-101/6-303
Scenario: Met Ed 2014 ADR Intangible
Dispersion: 7 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$38,038,716.98	$29,670,062.59	0.7800	$8,368,654.39	0.2200
Computed	$38,038,716.98	$28,739,390.46	0.7555	$9,299,326.52	0.2445
Difference		$930,672.13	0.0245	($930,672.13)	-0.0245

Generation Arrangement Report

Account: MTED-101/6-303
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$2,426,308.05	7.00	6.50	0.9286	1.0000	$2,253,000.33	$346,615.44
2012	1.50	$1,965,581.28	7.00	5.50	0.7857	1.0000	$1,544,385.29	$280,797.33
2011	2.50	$5,239,256.68	7.00	4.50	0.6429	1.0000	$3,368,093.58	$748,465.24
2010	3.50	$1,296,663.99	7.00	3.50	0.5000	1.0000	$648,332.00	$185,237.71
2009	4.50	$2,395,595.32	7.00	2.50	0.3571	1.0000	$855,569.76	$342,227.90
2008	5.50	$754,155.12	7.00	1.50	0.2143	1.0000	$161,604.67	$107,736.45
2007	6.50	$6,556,772.60	7.00	0.50	0.0714	1.0000	$468,340.90	$936,681.80
2006	7.50	$1,212,256.65	7.00	0.00	0.0000	0.0000	$0.00	$0.00
2005	8.50	$794,414.65	7.00	0.00	0.0000	0.0000	$0.00	$0.00
2004	9.50	$3,919,197.54	7.00	0.00	0.0000	0.0000	$0.00	$0.00
2003	10.50	$8,906,879.41	7.00	0.00	0.0000	0.0000	$0.00	$0.00
2002	11.50	$126,412.52	7.00	0.00	0.0000	0.0000	$0.00	$0.00
2001	12.50	$575,318.25	7.00	0.00	0.0000	0.0000	$0.00	$0.00
2000	13.50	$58,628.45	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1997	16.50	$32,387.07	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1994	19.50	$1,778,889.40	7.00	0.00	0.0000	0.0000	$0.00	$0.00
		$38,038,716.98	7.00	1.71	0.2445	1.0000	$9,299,326.52	$2,947,761.86

Remaining Life Depreciation Accrual

Account: MTED-101/6-301
Scenario: Met Ed 2014 ADR Intangible
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$123,507.40	0.00	$123,507.40	100.000000%	100.000000%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$123,507.40 *		$123,507.40	100.000000%	100.000000%
Average:	$123,507.40		$123,507.40	100.000000%	100.000000%
Grand Total:	$123,507.40 *		$123,507.40	100.000000%	100.000000%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED-101/6-301
Scenario: Met Ed 2014 ADR Intangible
Dispersion: 7 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$123,507.40	$0.00	0.0000	$123,507.40	1.0000
Computed	$123,507.40	$123,507.40	1.0000	$0.00	0.0000
Difference		($123,507.40)	-1.0000	$123,507.40	1.0000

Generation Arrangement Report

Account: MTED-101/6-301
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1952	61.50	$12,096.44	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1946	67.50	$652.82	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1927	86.50	$7,077.29	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	87.50	$26,723.33	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1925	88.50	$10,807.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1924	89.50	$2,206.67	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1922	91.50	$35,824.33	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1921	92.50	$166.67	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1919	94.50	$1,666.67	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1918	95.50	$12,487.98	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1917	96.50	$10,028.20	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1915	98.50	$3,770.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
		$123,507.40	0.00	0.00	0.0000	1.0000	$0.00	$0.00

Remaining Life Depreciation Accrual

Account: MTED-101/6-302
Scenario: Met Ed 2014 ADR Intangible
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$165,168.91	0.49	$165,168.91	100.000000%	100.000000%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$165,168.91 *		$165,168.91	100.000000%	100.000000%
Average:	$165,168.91		$165,168.91	100.000000%	100.000000%
Grand Total:	$165,168.91 *		$165,168.91	100.000000%	100.000000%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED-101/6-302
Scenario: Met Ed 2014 ADR Intangible
Dispersion: 7 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$165,168.91	$0.00	0.0000	$165,168.91	1.0000
Computed	$165,168.91	$153,725.06	0.9307	$11,443.85	0.0693
Difference		($153,725.06)	-0.9307	$153,725.06	0.9307

Generation Arrangement Report

Account: MTED-101/6-302
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2012	1.50	$14,564.90	7.00	5.50	0.7857	1.0000	$11,443.85	$2,080.70
1971	42.50	$825.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1968	45.50	$2,985.52	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1967	46.50	$3,776.05	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1966	47.50	$2,260.57	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1963	50.50	$925.12	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1954	59.50	$1,231.59	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1953	60.50	$5,533.30	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1952	61.50	$4,749.62	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1950	63.50	$433.93	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1944	69.50	$394.89	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1942	71.50	$418.42	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1930	83.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1928	85.50	$780.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1927	86.50	$6,240.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	87.50	$780.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1924	89.50	$2,340.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1923	90.50	$9,360.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1922	91.50	$5,460.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1921	92.50	$13,650.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1920	93.50	$1,170.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1919	94.50	$780.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1918	95.50	$3,510.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1917	96.50	$2,340.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1916	97.50	$4,290.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1914	99.50	$2,340.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1913	100.50	$8,580.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1912	101.50	$10,140.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1911	102.50	$9,360.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1910	103.50	$23,010.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1909	104.50	$1,950.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1908	105.50	$2,340.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1907	106.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

Account: MTED-101/6-302
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1906	107.50	$1,560.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1905	108.50	$1,560.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1903	110.50	$1,560.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1902	111.50	$1,170.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1901	112.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1900	113.50	$780.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1898	115.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1897	116.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1895	118.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1894	119.50	$780.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1893	120.50	$1,170.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1892	121.50	$1,170.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1891	122.50	$5,000.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1890	123.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1886	127.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1885	128.50	$780.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
		$165,168.91	7.00	0.49	0.0693	1.0000	$11,443.85	$2,080.70

Remaining Life Depreciation Accrual

Account: MTED 101/6-35012 TRANS lines
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$26,933,492.88	38.23	$405,189.81	1.504409%	2.615479%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$26,933,492.88 *		$405,189.81	1.504409%	2.615479%
Average:	$26,933,492.88		$405,189.81	1.504409%	2.615479%
Grand Total:	$26,933,492.88 *		$405,189.81	1.504409%	2.615479%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-35012 TRANS lines
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 80 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$26,933,492.88	$11,441,502.03	0.4248	$15,491,990.85	0.5752
Computed	$26,933,492.88	$14,061,333.61	0.5221	$12,872,159.27	0.4779
Difference		($2,619,831.58)	-0.0973	$2,619,831.58	0.0973

Generation Arrangement Report

Account: MTED 101/6-35012 TRANS lines
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2011	2.50	$598.69	80.00	77.50	0.9688	1.0000	$579.98	$7.48
2009	4.50	$4.84	80.00	75.50	0.9438	1.0000	$4.57	$0.06
2007	6.50	$5,810.40	80.00	73.50	0.9188	1.0000	$5,338.30	$72.63
2003	10.50	$252,332.78	80.00	69.50	0.8688	1.0000	$219,214.10	$3,154.16
1996	17.50	$140.38	80.00	62.50	0.7813	1.0000	$109.67	$1.75
1995	18.50	$115.53	80.00	61.50	0.7688	1.0000	$88.81	$1.44
1994	19.50	$714,064.13	80.00	60.50	0.7563	1.0000	$540,011.00	$8,925.80
1993	20.50	$1,289,627.27	80.00	59.50	0.7438	1.0000	$959,160.28	$16,120.34
1992	21.50	$45,883.80	80.00	58.50	0.7313	1.0000	$33,552.53	$573.55
1991	22.50	$119,303.21	80.00	57.50	0.7188	1.0000	$85,749.18	$1,491.29
1990	23.50	$556,414.29	80.00	56.50	0.7063	1.0000	$392,967.59	$6,955.18
1989	24.50	$8,041.09	80.00	55.50	0.6938	1.0000	$5,578.51	$100.51
1988	25.50	$68,838.58	80.00	54.50	0.6813	1.0000	$46,896.28	$860.48
1987	26.50	$33,007.08	80.00	53.50	0.6688	1.0000	$22,073.48	$412.59
1986	27.50	$65,939.13	80.00	52.50	0.6563	1.0000	$43,272.55	$824.24
1985	28.50	$417,272.31	80.00	51.50	0.6438	1.0000	$268,619.05	$5,215.90
1984	29.50	$218,073.20	80.00	50.50	0.6313	1.0000	$137,658.71	$2,725.92
1983	30.50	$295,517.04	80.00	49.50	0.6188	1.0000	$182,851.17	$3,693.96
1982	31.50	$14,887.51	80.00	48.50	0.6063	1.0000	$9,025.55	$186.09
1981	32.50	$12,944.11	80.00	47.50	0.5938	1.0000	$7,685.57	$161.80
1980	33.50	$114,508.39	80.00	46.50	0.5813	1.0000	$66,558.00	$1,431.35
1979	34.50	$100,125.74	80.00	45.50	0.5688	1.0000	$56,946.51	$1,251.57
1978	35.50	$8,420.26	80.00	44.50	0.5563	1.0000	$4,683.77	$105.25
1977	36.50	$275,265.63	80.00	43.50	0.5438	1.0000	$149,675.69	$3,440.82
1976	37.50	$6,112,490.51	80.00	42.50	0.5313	1.0000	$3,247,260.58	$76,406.13
1975	38.50	$447,702.82	80.00	41.50	0.5188	1.0000	$232,245.84	$5,596.29
1974	39.50	$283,812.63	80.00	40.50	0.5063	1.0000	$143,680.14	$3,547.66
1973	40.50	$2,007,475.04	80.00	39.50	0.4938	1.0000	$991,190.80	$25,093.44
1972	41.50	$472,877.46	80.00	38.50	0.4813	1.0000	$227,572.28	$5,910.97
1971	42.50	$1,266,471.73	80.00	37.50	0.4688	1.0000	$593,658.62	$15,830.90
1970	43.50	$845,645.51	80.00	36.50	0.4563	1.0000	$385,825.76	$10,570.57
1969	44.50	$499,170.03	80.00	35.50	0.4438	1.0000	$221,506.70	$6,239.63
1968	45.50	$1,954,050.94	80.00	34.50	0.4313	1.0000	$842,684.47	$24,425.64

Generation Arrangement Report

Account: MTED 101/6-35012 TRANS lines
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1967	46.50	$3,097,937.83	80.00	33.50	0.4188	1.0000	$1,297,261.47	$38,724.22
1966	47.50	$711,865.75	80.00	32.50	0.4063	1.0000	$289,195.46	$8,898.32
1965	48.50	$272,165.88	80.00	31.50	0.3938	1.0000	$107,165.32	$3,402.07
1964	49.50	$161,209.48	80.00	30.50	0.3813	1.0000	$61,461.11	$2,015.12
1963	50.50	$330,660.51	80.00	29.50	0.3688	1.0000	$121,931.06	$4,133.26
1962	51.50	$78,738.70	80.00	28.50	0.3563	1.0000	$28,050.66	$984.23
1961	52.50	$131,977.42	80.00	27.50	0.3438	1.0000	$45,367.24	$1,649.72
1960	53.50	$67,357.92	80.00	26.50	0.3313	1.0000	$22,312.31	$841.97
1959	54.50	$387,424.80	80.00	25.50	0.3188	1.0000	$123,491.65	$4,842.81
1958	55.50	$39,497.40	80.00	24.50	0.3063	1.0000	$12,096.08	$493.72
1957	56.50	$194,240.54	80.00	23.50	0.2938	1.0000	$57,058.16	$2,428.01
1956	57.50	$159,988.62	80.00	22.50	0.2813	1.0000	$44,996.80	$1,999.86
1955	58.50	$218,293.92	80.00	21.50	0.2688	1.0000	$58,666.49	$2,728.67
1954	59.50	$630,233.45	80.00	20.50	0.2563	1.0000	$161,497.32	$7,877.92
1953	60.50	$609,458.00	80.00	19.50	0.2438	1.0000	$148,555.39	$7,618.23
1952	61.50	$138,944.04	80.00	18.50	0.2313	1.0000	$32,130.81	$1,736.80
1951	62.50	$86,567.94	80.00	17.50	0.2188	1.0000	$18,936.74	$1,082.10
1950	63.50	$201,972.46	80.00	16.50	0.2063	1.0000	$41,656.82	$2,524.66
1949	64.50	$67,095.54	80.00	15.50	0.1938	1.0000	$12,999.76	$838.69
1948	65.50	$57,629.06	80.00	14.50	0.1813	1.0000	$10,445.27	$720.36
1947	66.50	$6,420.22	80.00	13.50	0.1688	1.0000	$1,083.41	$80.25
1946	67.50	$215.95	80.00	12.50	0.1563	1.0000	$33.74	$2.70
1945	68.50	$12,030.13	80.00	11.50	0.1438	1.0000	$1,729.33	$150.38
1944	69.50	$3,053.77	80.00	10.50	0.1313	1.0000	$400.81	$38.17
1943	70.50	$42,642.59	80.00	9.50	0.1188	1.0000	$5,063.81	$533.03
1942	71.50	$29,045.25	80.00	8.50	0.1063	1.0000	$3,086.06	$363.07
1941	72.50	$74,176.31	80.00	7.50	0.0938	1.0000	$6,954.03	$927.20
1940	73.50	$1,737.64	80.00	6.50	0.0813	1.0000	$141.18	$21.72
1939	74.50	$368.25	80.00	5.50	0.0688	1.0000	$25.32	$4.60
1938	75.50	$612,259.53	80.00	4.50	0.0563	1.0000	$34,439.60	$7,653.24
1929	84.50	$313.17	80.00	0.00	0.0000	0.0000	$0.00	$0.00
1924	89.50	$891.75	80.00	0.00	0.0000	0.0000	$0.00	$0.00
1914	99.50	$2.00	80.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

Account: MTED 101/6-35012 TRANS lines
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1907	106.50	$25.00	80.00	0.00	0.0000	0.0000	$0.00	$0.00
1901	112.50	$220.00	80.00	0.00	0.0000	0.0000	$0.00	$0.00
		$26,933,492.88	80.00	38.23	0.4779	1.0000	$12,872,159.27	$336,650.51

Remaining Life Depreciation Accrual

Account: MTED 101/6-352 Structures/improve
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 58.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$6,720,251.60	32.54	$123,768.65	1.841726%	3.073301%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($81,766.79)	0.50	($704.89)	0.862074%	
Total:	$6,720,251.60 *		$123,063.76	1.831237%	3.055798%
Average:	$6,679,368.21		$123,063.76	1.842446%	3.087138%
Grand Total:	$6,720,251.60 *		$123,063.76	1.831237%	3.055798%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-352 Structures/improve
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 58 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$6,720,251.60	$2,693,029.63	0.4007	$4,027,221.97	0.5993
Computed	$6,720,251.60	$2,950,155.17	0.4390	$3,770,096.43	0.5610
Difference		($257,125.54)	-0.0383	$257,125.54	0.0383

Generation Arrangement Report

Account: MTED 101/6-352 Structures/improve
Dispersion: 58.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$115,564.04	58.00	57.51	0.9915	1.0000	$114,582.36	$1,992.48
2012	1.50	$527,355.57	58.00	56.52	0.9746	1.0000	$513,941.60	$9,092.34
2011	2.50	$681,811.78	58.00	55.54	0.9576	1.0000	$652,935.69	$11,755.38
2007	6.50	$2,116.65	58.00	51.65	0.8905	1.0000	$1,884.80	$36.49
2006	7.50	$10,711.03	58.00	50.68	0.8738	1.0000	$9,359.30	$184.67
2003	10.50	$856.48	58.00	47.80	0.8242	1.0000	$705.92	$14.77
2001	12.50	$118,437.06	58.00	45.91	0.7915	1.0000	$93,744.49	$2,042.02
2000	13.50	$28,523.81	58.00	44.97	0.7753	1.0000	$22,114.64	$491.79
1999	14.50	$17,215.09	58.00	44.03	0.7592	1.0000	$13,069.20	$296.81
1998	15.50	$4,008.60	58.00	43.10	0.7431	1.0000	$2,978.92	$69.11
1996	17.50	$22,039.63	58.00	41.26	0.7114	1.0000	$15,678.25	$379.99
1995	18.50	$8,844.99	58.00	40.35	0.6956	1.0000	$6,152.86	$152.50
1994	19.50	$61,378.57	58.00	39.44	0.6800	1.0000	$41,738.08	$1,058.25
1993	20.50	$13,360.88	58.00	38.54	0.6645	1.0000	$8,878.67	$230.36
1992	21.50	$145,373.97	58.00	37.65	0.6491	1.0000	$94,368.40	$2,506.45
1991	22.50	$388,261.82	58.00	36.76	0.6339	1.0000	$246,109.44	$6,694.17
1990	23.50	$430,859.49	58.00	35.89	0.6187	1.0000	$266,585.40	$7,428.61
1989	24.50	$11,649.27	58.00	35.02	0.6038	1.0000	$7,033.25	$200.85
1988	25.50	$189,670.87	58.00	34.15	0.5889	1.0000	$111,692.15	$3,270.19
1987	26.50	$26,159.62	58.00	33.30	0.5741	1.0000	$15,019.08	$451.03
1986	27.50	$326,108.13	58.00	32.45	0.5596	1.0000	$182,477.19	$5,622.55
1985	28.50	$813,258.20	58.00	31.62	0.5451	1.0000	$443,311.09	$14,021.69
1984	29.50	$16,541.60	58.00	30.79	0.5308	1.0000	$8,780.13	$285.20
1983	30.50	$47,435.12	58.00	29.96	0.5166	1.0000	$24,505.57	$817.85
1982	31.50	$16,828.77	58.00	29.15	0.5026	1.0000	$8,458.69	$290.15
1981	32.50	$1,155.53	58.00	28.35	0.4888	1.0000	$564.79	$19.92
1980	33.50	$1,203.31	58.00	27.55	0.4751	1.0000	$571.65	$20.75
1978	35.50	$1,291.00	58.00	25.99	0.4482	1.0000	$578.59	$22.26
1977	36.50	$12,628.40	58.00	25.23	0.4349	1.0000	$5,492.69	$217.73
1976	37.50	$520,759.70	58.00	24.47	0.4219	1.0000	$219,703.14	$8,978.62
1975	38.50	$15,881.75	58.00	23.73	0.4091	1.0000	$6,496.54	$273.82
1974	39.50	$4,418.89	58.00	22.99	0.3964	1.0000	$1,751.50	$76.19
1973	40.50	$223,885.85	58.00	22.26	0.3839	1.0000	$85,939.10	$3,860.10

Generation Arrangement Report

Account: MTED 101/6-352 Structures/improve
Dispersion: 58.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1972	41.50	$78,917.81	58.00	21.55	0.3715	1.0000	$29,319.64	$1,360.65
1971	42.50	$182,292.59	58.00	20.85	0.3594	1.0000	$65,524.29	$3,142.98
1970	43.50	$458,817.08	58.00	20.16	0.3475	1.0000	$159,450.54	$7,910.64
1969	44.50	$161,790.02	58.00	19.48	0.3358	1.0000	$54,329.81	$2,789.48
1968	45.50	$169,691.80	58.00	18.81	0.3244	1.0000	$55,039.58	$2,925.72
1967	46.50	$3,072.67	58.00	18.16	0.3131	1.0000	$962.00	$52.98
1966	47.50	$93,939.69	58.00	17.52	0.3020	1.0000	$28,373.25	$1,619.65
1965	48.50	$20,753.26	58.00	16.89	0.2912	1.0000	$6,043.67	$357.81
1964	49.50	$1,948.25	58.00	16.28	0.2807	1.0000	$546.90	$33.59
1963	50.50	$83,377.78	58.00	15.68	0.2704	1.0000	$22,545.98	$1,437.55
1962	51.50	$33,966.72	58.00	15.10	0.2604	1.0000	$8,843.27	$585.63
1961	52.50	$230.12	58.00	14.53	0.2506	1.0000	$57.66	$3.97
1960	53.50	$306.55	58.00	13.98	0.2411	1.0000	$73.91	$5.29
1959	54.50	$3,674.92	58.00	13.45	0.2319	1.0000	$852.09	$63.36
1958	55.50	$56,306.56	58.00	12.93	0.2229	1.0000	$12,550.82	$970.80
1957	56.50	$4,813.27	58.00	12.43	0.2143	1.0000	$1,031.33	$82.99
1956	57.50	$965.78	58.00	11.94	0.2059	1.0000	$198.84	$16.65
1955	58.50	$40,439.48	58.00	11.47	0.1978	1.0000	$7,997.92	$697.23
1954	59.50	$385,982.74	58.00	11.02	0.1899	1.0000	$73,317.33	$6,654.87
1953	60.50	$4,365.90	58.00	10.58	0.1824	1.0000	$796.51	$75.27
1952	61.50	$9,802.69	58.00	10.16	0.1752	1.0000	$1,717.24	$169.01
1951	62.50	$10,249.96	58.00	9.76	0.1682	1.0000	$1,723.99	$176.72
1950	63.50	$114.70	58.00	9.37	0.1615	1.0000	$18.52	$1.98
1949	64.50	$2,483.47	58.00	8.99	0.1550	1.0000	$384.97	$42.82
1948	65.50	$3,450.08	58.00	8.63	0.1488	1.0000	$513.39	$59.48
1947	66.50	$121.29	58.00	8.29	0.1428	1.0000	$17.33	$2.09
1946	67.50	$177.20	58.00	7.95	0.1371	1.0000	$24.29	$3.06
1944	69.50	$16.48	58.00	7.32	0.1262	1.0000	$2.08	$0.28
1943	70.50	$22,891.38	58.00	7.02	0.1211	1.0000	$2,771.23	$394.68
1942	71.50	$989.13	58.00	6.73	0.1160	1.0000	$114.70	$17.05
1941	72.50	$7,051.74	58.00	6.44	0.1111	1.0000	$783.47	$121.58
1940	73.50	$1,225.20	58.00	6.17	0.1064	1.0000	$130.35	$21.12

Generation Arrangement Report

Account: MTED 101/6-352 Structures/improve
Dispersion: 58.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1938	75.50	$70,429.82	58.00	5.63	0.0971	1.0000	$6,836.44	$1,214.31
		$6,720,251.60	58.00	32.54	0.5610	1.0000	$3,770,096.43	$115,866.41

Remaining Life Depreciation Accrual

Account: MTED 101/6-353 Station equipment
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 54.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$182,774,706.85	41.49	$3,070,848.81	1.680128%	2.410386%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($1,519,777.21)	0.50	($14,072.01)	0.925926%	
Total:	$182,774,706.85 *		$3,056,776.80	1.672429%	2.399341%
Average:	$182,014,818.25		$3,056,776.80	1.679411%	2.413738%
Grand Total:	$182,774,706.85 *		$3,056,776.80	1.672429%	2.399341%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-353 Station equipment
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 54 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$182,774,706.85	$55,374,009.34	0.3030	$127,400,697.51	0.6970
Computed	$182,774,706.85	$42,352,527.87	0.2317	$140,422,178.98	0.7683
Difference		$13,021,481.47	0.0712	($13,021,481.47)	-0.0712

Generation Arrangement Report

Account: MTED 101/6-353 Station equipment
Dispersion: 54.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$17,711,242.73	54.00	53.59	0.9924	1.0000	$17,575,973.29	$327,985.98
2012	1.50	$15,088,016.24	54.00	52.77	0.9772	1.0000	$14,743,429.52	$279,407.71
2011	2.50	$9,336,502.49	54.00	51.95	0.9620	1.0000	$8,981,971.24	$172,898.19
2010	3.50	$5,430,008.11	54.00	51.14	0.9470	1.0000	$5,142,175.11	$100,555.71
2009	4.50	$5,534,612.62	54.00	50.33	0.9320	1.0000	$5,158,411.24	$102,492.83
2008	5.50	$22,539,649.56	54.00	49.53	0.9171	1.0000	$20,671,916.03	$417,400.92
2007	6.50	$1,136,930.86	54.00	48.73	0.9023	1.0000	$1,025,889.19	$21,054.28
2006	7.50	$15,018,631.61	54.00	47.93	0.8876	1.0000	$13,330,426.73	$278,122.81
2005	8.50	$1,196,085.76	54.00	47.14	0.8729	1.0000	$1,044,121.49	$22,149.74
2004	9.50	$2,138,089.13	54.00	46.35	0.8584	1.0000	$1,835,265.26	$39,594.24
2003	10.50	$1,553,017.81	54.00	45.57	0.8439	1.0000	$1,310,588.26	$28,759.59
2002	11.50	$854,624.86	54.00	44.79	0.8295	1.0000	$708,907.40	$15,826.39
2001	12.50	$1,972,949.42	54.00	44.02	0.8152	1.0000	$1,608,282.29	$36,536.10
2000	13.50	$4,164,821.23	54.00	43.25	0.8009	1.0000	$3,335,712.11	$77,126.32
1999	14.50	$373,481.18	54.00	42.49	0.7868	1.0000	$293,840.63	$6,916.32
1998	15.50	$2,352,556.40	54.00	41.72	0.7727	1.0000	$1,817,767.21	$43,565.86
1997	16.50	$3,174,547.96	54.00	40.97	0.7587	1.0000	$2,408,424.47	$58,787.93
1996	17.50	$1,316,481.42	54.00	40.22	0.7448	1.0000	$980,487.40	$24,379.29
1995	18.50	$2,061,051.55	54.00	39.47	0.7310	1.0000	$1,506,527.97	$38,167.62
1994	19.50	$4,818,901.86	54.00	38.73	0.7172	1.0000	$3,456,185.40	$89,238.92
1993	20.50	$1,542,148.13	54.00	37.99	0.7036	1.0000	$1,085,001.61	$28,558.30
1992	21.50	$5,142,419.52	54.00	37.26	0.6900	1.0000	$3,548,302.56	$95,229.99
1991	22.50	$2,905,098.40	54.00	36.53	0.6766	1.0000	$1,965,446.64	$53,798.12
1990	23.50	$1,206,121.63	54.00	35.81	0.6632	1.0000	$799,889.69	$22,335.59
1989	24.50	$1,909,405.54	54.00	35.10	0.6500	1.0000	$1,241,043.16	$35,359.36
1988	25.50	$695,245.92	54.00	34.39	0.6368	1.0000	$442,747.84	$12,874.92
1987	26.50	$1,528,105.30	54.00	33.68	0.6238	1.0000	$953,216.75	$28,298.25
1986	27.50	$5,955,111.88	54.00	32.99	0.6109	1.0000	$3,637,805.84	$110,279.85
1985	28.50	$3,273,016.86	54.00	32.30	0.5981	1.0000	$1,957,481.92	$60,611.42
1984	29.50	$937,822.05	54.00	31.61	0.5854	1.0000	$548,989.05	$17,367.08
1983	30.50	$1,999,765.58	54.00	30.93	0.5729	1.0000	$1,145,584.85	$37,032.70
1982	31.50	$290,631.19	54.00	30.26	0.5604	1.0000	$162,881.63	$5,382.06
1981	32.50	$306,681.83	54.00	29.60	0.5482	1.0000	$168,108.26	$5,679.29

Generation Arrangement Report

Account: MTED 101/6-353 Station equipment
Dispersion: 54.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$136,481.87	54.00	28.94	0.5360	1.0000	$73,153.05	$2,527.44
1979	34.50	$164,033.48	54.00	28.29	0.5240	1.0000	$85,949.01	$3,037.66
1978	35.50	$359,976.38	54.00	27.65	0.5121	1.0000	$184,341.73	$6,666.23
1977	36.50	$627,965.42	54.00	27.02	0.5004	1.0000	$314,209.16	$11,628.99
1976	37.50	$10,927,192.05	54.00	26.40	0.4888	1.0000	$5,341,325.67	$202,355.41
1975	38.50	$1,397,460.57	54.00	25.78	0.4774	1.0000	$667,123.03	$25,878.90
1974	39.50	$171,627.72	54.00	25.17	0.4661	1.0000	$79,996.94	$3,178.29
1973	40.50	$2,225,820.54	54.00	24.57	0.4550	1.0000	$1,012,722.35	$41,218.90
1972	41.50	$2,112,311.72	54.00	23.98	0.4440	1.0000	$937,928.46	$39,116.88
1971	42.50	$3,032,055.86	54.00	23.39	0.4332	1.0000	$1,313,579.80	$56,149.18
1970	43.50	$3,913,011.65	54.00	22.82	0.4226	1.0000	$1,653,626.56	$72,463.18
1969	44.50	$2,016,255.10	54.00	22.26	0.4122	1.0000	$831,024.81	$37,338.06
1968	45.50	$1,672,176.69	54.00	21.70	0.4019	1.0000	$671,993.84	$30,966.24
1967	46.50	$273,895.63	54.00	21.15	0.3918	1.0000	$107,299.30	$5,072.14
1966	47.50	$734,335.72	54.00	20.62	0.3818	1.0000	$280,371.97	$13,598.81
1965	48.50	$417,778.99	54.00	20.09	0.3720	1.0000	$155,425.18	$7,736.65
1964	49.50	$280,660.42	54.00	19.57	0.3624	1.0000	$101,720.02	$5,197.42
1963	50.50	$964,183.06	54.00	19.06	0.3530	1.0000	$340,363.30	$17,855.24
1962	51.50	$1,148,454.27	54.00	18.57	0.3438	1.0000	$394,839.92	$21,267.67
1961	52.50	$73,714.48	54.00	18.08	0.3347	1.0000	$24,675.46	$1,365.08
1960	53.50	$37,385.01	54.00	17.60	0.3259	1.0000	$12,182.63	$692.32
1959	54.50	$82,021.29	54.00	17.13	0.3172	1.0000	$26,014.90	$1,518.91
1958	55.50	$387,087.62	54.00	16.67	0.3087	1.0000	$119,476.73	$7,168.29
1957	56.50	$62,048.43	54.00	16.22	0.3003	1.0000	$18,634.49	$1,149.04
1956	57.50	$27,159.28	54.00	15.78	0.2922	1.0000	$7,935.25	$502.95
1955	58.50	$350,309.27	54.00	15.35	0.2842	1.0000	$99,556.25	$6,487.21
1954	59.50	$2,470,352.51	54.00	14.93	0.2764	1.0000	$682,781.44	$45,747.27
1953	60.50	$99,103.12	54.00	14.51	0.2688	1.0000	$26,634.80	$1,835.24
1952	61.50	$524,611.28	54.00	14.11	0.2613	1.0000	$137,081.14	$9,715.02
1951	62.50	$183,303.34	54.00	13.72	0.2540	1.0000	$46,559.82	$3,394.51
1950	63.50	$25,425.20	54.00	13.33	0.2469	1.0000	$6,276.82	$470.84
1949	64.50	$10,109.54	54.00	12.95	0.2399	1.0000	$2,425.17	$187.21
1948	65.50	$11,564.26	54.00	12.59	0.2331	1.0000	$2,695.23	$214.15

Generation Arrangement Report

Account: MTED 101/6-353 Station equipment
Dispersion: 54.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$3,959.46	54.00	12.22	0.2264	1.0000	$896.37	$73.32
1946	67.50	$4,539.60	54.00	11.87	0.2199	1.0000	$998.06	$84.07
1945	68.50	$210.47	54.00	11.53	0.2135	1.0000	$44.93	$3.90
1944	69.50	$63.23	54.00	11.19	0.2072	1.0000	$13.10	$1.17
1943	70.50	$169,340.16	54.00	10.86	0.2011	1.0000	$34,047.27	$3,135.93
1942	71.50	$10,729.47	54.00	10.53	0.1950	1.0000	$2,091.97	$198.69
1941	72.50	$107,057.03	54.00	10.21	0.1890	1.0000	$20,238.23	$1,982.54
1940	73.50	$5,236.29	54.00	9.89	0.1832	1.0000	$959.37	$96.97
1938	75.50	$239.19	54.00	9.28	0.1718	1.0000	$41.10	$4.43
1937	76.50	$9.93	54.00	8.98	0.1663	1.0000	$1.65	$0.18
1935	78.50	$207.77	54.00	8.39	0.1553	1.0000	$32.27	$3.85
1931	82.50	$1,999.70	54.00	7.26	0.1344	1.0000	$268.81	$37.03
1930	83.50	$7,822.42	54.00	6.99	0.1294	1.0000	$1,012.33	$144.86
1929	84.50	$13,003.33	54.00	6.72	0.1244	1.0000	$1,617.17	$240.80
1928	85.50	$1,055.93	54.00	6.45	0.1195	1.0000	$126.18	$19.55
1927	86.50	$15,345.49	54.00	6.20	0.1147	1.0000	$1,760.54	$284.18
1926	87.50	$13,413.17	54.00	5.94	0.1101	1.0000	$1,476.45	$248.39
1925	88.50	$30,965.46	54.00	5.70	0.1055	1.0000	$3,268.21	$573.43
1924	89.50	$16.03	54.00	5.46	0.1011	1.0000	$1.62	$0.30
1923	90.50	$5,325.98	54.00	5.23	0.0969	1.0000	$515.93	$98.63
1922	91.50	$130.19	54.00	4.99	0.0925	1.0000	$12.04	$2.41
1921	92.50	$75.66	54.00	4.77	0.0883	1.0000	$6.68	$1.40
1919	94.50	$263.37	54.00	4.33	0.0801	1.0000	$21.10	$4.88
1909	104.50	$49.12	54.00	1.45	0.0268	1.0000	$1.32	$0.91
		$182,774,706.85	54.00	41.49	0.7683	1.0000	$140,422,178.98	$3,384,716.79

Remaining Life Depreciation Accrual

Account: MTED 101/6-354 Towers & Fixtures
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 65.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$41,082,523.92	30.36	$476,490.82	1.159838%	3.293486%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($503,192.29)	0.50	($3,870.71)	0.769231%	
Total:	$41,082,523.92 *		$472,620.11	1.150416%	3.266732%
Average:	$40,830,927.78		$472,620.11	1.157505%	3.324547%
Grand Total:	$41,082,523.92 *		$472,620.11	1.150416%	3.266732%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-354 Towers & Fixtures
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 65 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$41,082,523.92	$26,614,851.88	0.6478	$14,467,672.04	0.3522
Computed	$41,082,523.92	$21,891,953.53	0.5329	$19,190,570.39	0.4671
Difference		$4,722,898.35	0.1150	($4,722,898.35)	-0.1150

Generation Arrangement Report

Account: MTED 101/6-354 Towers & Fixtures
Dispersion: 65.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2012	1.50	$1,761,705.82	65.00	63.52	0.9773	1.0000	$1,721,710.06	$27,103.17
2011	2.50	$2,534,903.85	65.00	62.54	0.9622	1.0000	$2,439,063.33	$38,998.52
2007	6.50	($859.01)	65.00	58.64	0.9022	1.0000	($774.97)	($13.22)
2002	11.50	$9,249.26	65.00	53.83	0.8281	1.0000	$7,659.52	$142.30
2001	12.50	$95,829.19	65.00	52.88	0.8135	1.0000	$77,956.38	$1,474.30
1998	15.50	$1,467.10	65.00	50.05	0.7700	1.0000	$1,129.60	$22.57
1993	20.50	$132,283.11	65.00	45.43	0.6989	1.0000	$92,449.19	$2,035.12
1992	21.50	$39,700.54	65.00	44.52	0.6849	1.0000	$27,192.32	$610.78
1991	22.50	$10,026.50	65.00	43.62	0.6711	1.0000	$6,728.32	$154.25
1989	24.50	$26,995.32	65.00	41.83	0.6436	1.0000	$17,374.16	$415.31
1986	27.50	$604,439.36	65.00	39.21	0.6032	1.0000	$364,583.10	$9,299.07
1985	28.50	$1,131,748.22	65.00	38.34	0.5899	1.0000	$667,609.69	$17,411.51
1984	29.50	$978,223.02	65.00	37.49	0.5767	1.0000	$564,189.10	$15,049.58
1976	37.50	$10,301,082.61	65.00	30.91	0.4756	1.0000	$4,898,976.34	$158,478.19
1974	39.50	$645,296.58	65.00	29.35	0.4515	1.0000	$291,368.40	$9,927.64
1973	40.50	$329,661.86	65.00	28.58	0.4397	1.0000	$144,956.79	$5,071.72
1972	41.50	$173,400.62	65.00	27.82	0.4280	1.0000	$74,215.00	$2,667.70
1971	42.50	$2,263,525.90	65.00	27.07	0.4165	1.0000	$942,653.67	$34,823.48
1970	43.50	$2,521,730.04	65.00	26.33	0.4050	1.0000	$1,021,346.34	$38,795.85
1968	45.50	$4,679,465.36	65.00	24.87	0.3826	1.0000	$1,790,452.39	$71,991.77
1967	46.50	$6,612,656.50	65.00	24.15	0.3716	1.0000	$2,457,331.58	$101,733.18
1966	47.50	$1,337,384.34	65.00	23.45	0.3608	1.0000	$482,558.65	$20,575.14
1965	48.50	$4,008.81	65.00	22.76	0.3501	1.0000	$1,403.61	$61.67
1964	49.50	$24.52	65.00	22.08	0.3397	1.0000	$8.33	$0.38
1963	50.50	$50,713.84	65.00	21.41	0.3293	1.0000	$16,700.91	$780.21
1962	51.50	$55,077.00	65.00	20.75	0.3192	1.0000	$17,580.63	$847.34
1960	53.50	$17,765.87	65.00	19.46	0.2995	1.0000	$5,320.00	$273.32
1959	54.50	$180,389.43	65.00	18.84	0.2898	1.0000	$52,283.13	$2,775.22
1957	56.50	$128,568.38	65.00	17.63	0.2713	1.0000	$34,874.44	$1,977.98
1956	57.50	$26,134.23	65.00	17.05	0.2623	1.0000	$6,854.53	$402.07
1955	58.50	$109,452.98	65.00	16.48	0.2535	1.0000	$27,745.37	$1,683.89
1954	59.50	$2,484,182.81	65.00	15.92	0.2449	1.0000	$608,349.56	$38,218.20
1953	60.50	$970,063.28	65.00	15.38	0.2366	1.0000	$229,500.18	$14,924.05

Generation Arrangement Report

Account: MTED 101/6-354 Towers & Fixtures
Dispersion: 65.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1951	62.50	$54,557.17	65.00	14.34	0.2206	1.0000	$12,032.93	$839.34
1950	63.50	$85,910.00	65.00	13.84	0.2129	1.0000	$18,286.37	$1,321.69
1948	65.50	$2,335.61	65.00	12.88	0.1982	1.0000	$462.88	$35.93
1943	70.50	$1,939.14	65.00	10.75	0.1654	1.0000	$320.75	$29.83
1941	72.50	$128,574.12	65.00	10.00	0.1538	1.0000	$19,774.27	$1,978.06
1940	73.50	$9,720.09	65.00	9.64	0.1483	1.0000	$1,441.15	$149.54
1931	82.50	$13,302.87	65.00	6.88	0.1058	1.0000	$1,407.08	$204.66
1930	83.50	$9,071.14	65.00	6.60	0.1016	1.0000	$921.30	$139.56
1929	84.50	$4,164.81	65.00	6.34	0.0975	1.0000	$406.07	$64.07
1928	85.50	$44,404.24	65.00	6.08	0.0936	1.0000	$4,155.60	$683.14
1926	87.50	$2,669.76	65.00	5.56	0.0856	1.0000	$228.53	$41.07
1925	88.50	$59,148.39	65.00	5.30	0.0815	1.0000	$4,820.65	$909.98
1924	89.50	$447,111.66	65.00	5.05	0.0777	1.0000	$34,726.96	$6,878.64
1923	90.50	$2,313.86	65.00	4.78	0.0736	1.0000	$170.26	$35.60
1921	92.50	$1,003.82	65.00	4.27	0.0657	1.0000	$65.91	$15.44
		$41,082,523.92	65.00	30.36	0.4671	1.0000	$19,190,570.39	$632,038.83

Remaining Life Depreciation Accrual

Account: MTED 101/6-355 Poles & Fixtures
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 62.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$46,196,355.38	41.97	$672,510.91	1.455766%	2.382549%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($226,356.08)	0.50	($1,825.45)	0.806451%	
Total:	$46,196,355.38 *		$670,685.46	1.451815%	2.376082%
Average:	$46,083,177.34		$670,685.46	1.455380%	2.385647%
Grand Total:	$46,196,355.38 *		$670,685.46	1.451815%	2.376082%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-355 Poles & Fixtures
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 62 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$46,196,355.38	$17,969,822.96	0.3890	$28,226,532.42	0.6110
Computed	$46,196,355.38	$14,923,018.66	0.3230	$31,273,336.72	0.6770
Difference		$3,046,804.30	0.0660	($3,046,804.30)	-0.0660

Generation Arrangement Report

Account: MTED 101/6-355 Poles & Fixtures
Dispersion: 62.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$3,029,409.59	62.00	61.51	0.9921	1.0000	$3,005,332.18	$48,861.45
2012	1.50	$3,271,398.34	62.00	60.52	0.9762	1.0000	$3,193,543.14	$52,764.49
2011	2.50	$535,871.97	62.00	59.54	0.9604	1.0000	$514,635.39	$8,643.10
2010	3.50	$442,549.94	62.00	58.56	0.9446	1.0000	$418,023.23	$7,137.90
2009	4.50	$813,013.04	62.00	57.59	0.9288	1.0000	$755,155.04	$13,113.11
2008	5.50	$1,208,501.98	62.00	56.61	0.9131	1.0000	$1,103,515.97	$19,491.97
2007	6.50	$176,834.00	62.00	55.64	0.8975	1.0000	$158,703.35	$2,852.16
2006	7.50	$620,340.34	62.00	54.68	0.8819	1.0000	$547,051.75	$10,005.49
2005	8.50	$746,112.64	62.00	53.71	0.8663	1.0000	$646,350.75	$12,034.07
2004	9.50	$193,787.37	62.00	52.75	0.8508	1.0000	$164,873.54	$3,125.60
2003	10.50	$589,122.70	62.00	51.79	0.8354	1.0000	$492,125.40	$9,501.98
2002	11.50	$980,582.22	62.00	50.84	0.8200	1.0000	$804,047.34	$15,815.84
2001	12.50	$711,438.68	62.00	49.89	0.8047	1.0000	$572,469.52	$11,474.82
2000	13.50	$409,303.59	62.00	48.94	0.7894	1.0000	$323,112.92	$6,601.67
1999	14.50	$1,429,600.75	62.00	48.00	0.7743	1.0000	$1,106,884.99	$23,058.08
1998	15.50	$2,037,784.45	62.00	47.07	0.7592	1.0000	$1,547,026.32	$32,867.49
1997	16.50	$842,135.06	62.00	46.14	0.7442	1.0000	$626,682.21	$13,582.82
1996	17.50	$328,169.07	62.00	45.21	0.7293	1.0000	$239,319.23	$5,293.05
1995	18.50	$1,784,836.16	62.00	44.29	0.7144	1.0000	$1,275,109.40	$28,787.68
1994	19.50	$572,372.29	62.00	43.38	0.6997	1.0000	$400,483.98	$9,231.81
1993	20.50	$3,204,761.56	62.00	42.47	0.6850	1.0000	$2,195,415.86	$51,689.70
1992	21.50	$785,000.00	62.00	41.57	0.6705	1.0000	$526,341.99	$12,661.29
1991	22.50	$782,794.43	62.00	40.68	0.6561	1.0000	$513,571.70	$12,625.72
1990	23.50	$2,013,233.04	62.00	39.79	0.6417	1.0000	$1,291,972.24	$32,471.50
1989	24.50	$504,555.78	62.00	38.90	0.6275	1.0000	$316,608.32	$8,138.00
1988	25.50	$1,464,033.72	62.00	38.03	0.6134	1.0000	$898,058.10	$23,613.45
1987	26.50	$1,083,455.82	62.00	37.16	0.5994	1.0000	$649,426.41	$17,475.09
1986	27.50	$1,006,871.14	62.00	36.30	0.5855	1.0000	$589,567.27	$16,239.86
1985	28.50	$3,108,695.61	62.00	35.45	0.5718	1.0000	$1,777,492.74	$50,140.25
1984	29.50	$425,251.10	62.00	34.60	0.5581	1.0000	$237,343.30	$6,858.89
1983	30.50	$750,166.09	62.00	33.77	0.5446	1.0000	$408,571.13	$12,099.45
1982	31.50	$253,926.31	62.00	32.94	0.5312	1.0000	$134,897.37	$4,095.59
1981	32.50	$568,289.01	62.00	32.12	0.5180	1.0000	$294,376.31	$9,165.95

Generation Arrangement Report

Account: MTED 101/6-355 Poles & Fixtures
Dispersion: 62.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$372,645.44	62.00	31.30	0.5049	1.0000	$188,138.95	$6,010.41
1979	34.50	$316,174.63	62.00	30.50	0.4919	1.0000	$155,514.76	$5,099.59
1978	35.50	$76,469.24	62.00	29.70	0.4790	1.0000	$36,631.76	$1,233.37
1977	36.50	$568,148.12	62.00	28.91	0.4663	1.0000	$264,934.32	$9,163.68
1976	37.50	$17,924.73	62.00	28.13	0.4538	1.0000	$8,133.49	$289.11
1975	38.50	$497,162.54	62.00	27.36	0.4413	1.0000	$219,410.16	$8,018.75
1974	39.50	$439,401.18	62.00	26.60	0.4290	1.0000	$188,513.12	$7,087.12
1973	40.50	$981,611.70	62.00	25.85	0.4169	1.0000	$409,251.56	$15,832.45
1972	41.50	$756,300.08	62.00	25.11	0.4049	1.0000	$306,247.83	$12,198.39
1971	42.50	$710,921.38	62.00	24.37	0.3931	1.0000	$279,453.73	$11,466.47
1970	43.50	$1,018,609.67	62.00	23.65	0.3815	1.0000	$388,567.15	$16,429.19
1969	44.50	$385,871.75	62.00	22.94	0.3700	1.0000	$142,758.06	$6,223.74
1968	45.50	$491,264.98	62.00	22.24	0.3587	1.0000	$176,202.37	$7,923.63
1967	46.50	$267,852.95	62.00	21.55	0.3475	1.0000	$93,085.02	$4,320.21
1966	47.50	$257,476.88	62.00	20.87	0.3365	1.0000	$86,651.35	$4,152.85
1965	48.50	$158,655.76	62.00	20.20	0.3258	1.0000	$51,691.99	$2,558.96
1964	49.50	$148,518.34	62.00	19.54	0.3152	1.0000	$46,816.14	$2,395.46
1963	50.50	$263,705.76	62.00	18.90	0.3049	1.0000	$80,397.74	$4,253.32
1962	51.50	$99,192.90	62.00	18.27	0.2947	1.0000	$29,232.42	$1,599.89
1961	52.50	$173,089.67	62.00	17.65	0.2847	1.0000	$49,283.01	$2,791.77
1960	53.50	$144,426.48	62.00	17.05	0.2750	1.0000	$39,721.47	$2,329.46
1959	54.50	$277,937.54	62.00	16.46	0.2655	1.0000	$73,793.42	$4,482.86
1958	55.50	$47,759.91	62.00	15.88	0.2562	1.0000	$12,235.69	$770.32
1957	56.50	$198,812.66	62.00	15.33	0.2472	1.0000	$49,144.63	$3,206.66
1956	57.50	$99,278.54	62.00	14.78	0.2384	1.0000	$23,664.35	$1,601.27
1955	58.50	$68,582.94	62.00	14.25	0.2298	1.0000	$15,762.27	$1,106.18
1954	59.50	$95,291.90	62.00	13.73	0.2215	1.0000	$21,106.94	$1,536.97
1953	60.50	$61,031.96	62.00	13.23	0.2134	1.0000	$13,024.29	$984.39
1952	61.50	$97,525.46	62.00	12.75	0.2056	1.0000	$20,052.06	$1,572.99
1951	62.50	$45,938.97	62.00	12.28	0.1980	1.0000	$9,096.83	$740.95
1950	63.50	$127,719.88	62.00	11.82	0.1907	1.0000	$24,357.40	$2,060.00
1949	64.50	$102,077.60	62.00	11.38	0.1836	1.0000	$18,743.83	$1,646.41
1948	65.50	$57,147.30	62.00	10.96	0.1768	1.0000	$10,102.36	$921.73

Generation Arrangement Report

Account: MTED 101/6-355 Poles & Fixtures
Dispersion: 62.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$6,507.93	62.00	10.55	0.1702	1.0000	$1,107.56	$104.97
1946	67.50	$1,397.44	62.00	10.16	0.1638	1.0000	$228.93	$22.54
1945	68.50	$886.26	62.00	9.78	0.1577	1.0000	$139.75	$14.29
1944	69.50	$2,207.87	62.00	9.41	0.1518	1.0000	$335.08	$35.61
1943	70.50	$20,762.85	62.00	9.06	0.1461	1.0000	$3,032.82	$334.88
1942	71.50	$2,753.24	62.00	8.71	0.1405	1.0000	$386.96	$44.41
1941	72.50	$46,796.33	62.00	8.39	0.1352	1.0000	$6,329.12	$754.78
1940	73.50	$3,084.38	62.00	8.07	0.1302	1.0000	$401.44	$49.75
1939	74.50	$265.23	62.00	7.76	0.1251	1.0000	$33.19	$4.28
1938	75.50	$12,263.11	62.00	7.46	0.1204	1.0000	$1,475.88	$197.79
1929	84.50	$704.11	62.00	5.03	0.0811	1.0000	$57.13	$11.36
		$46,196,355.38	62.00	41.97	0.6770	1.0000	$31,273,336.72	$745,102.51

Remaining Life Depreciation Accrual

Account: MTED 101/6-356 Overhead Conductor
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 65.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$67,409,524.29	42.87	$892,938.15	1.324647%	2.332716%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($453,109.78)	0.50	($3,485.46)	0.769231%	
Total:	$67,409,524.29 *		$889,452.69	1.319476%	2.323611%
Average:	$67,182,969.40		$889,452.69	1.323926%	2.337445%
Grand Total:	$67,409,524.29 *		$889,452.69	1.319476%	2.323611%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-356 Overhead Conductor
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 65 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$67,409,524.29	$29,130,620.58	0.4321	$38,278,903.71	0.5679
Computed	$67,409,524.29	$22,951,923.32	0.3405	$44,457,600.97	0.6595
Difference		$6,178,697.26	0.0917	($6,178,697.26)	-0.0917

Generation Arrangement Report

Account: MTED 101/6-356 Overhead Conductor
Dispersion: 65.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$2,584,860.78	65.00	64.53	0.9927	1.0000	$2,566,049.23	$39,767.09
2012	1.50	$5,028,149.84	65.00	63.58	0.9782	1.0000	$4,918,656.76	$77,356.15
2011	2.50	$897,488.62	65.00	62.64	0.9637	1.0000	$864,953.97	$13,807.52
2010	3.50	$769,697.05	65.00	61.71	0.9493	1.0000	$730,700.25	$11,841.49
2009	4.50	$1,408,079.60	65.00	60.77	0.9350	1.0000	$1,316,490.94	$21,662.76
2008	5.50	$3,351,810.27	65.00	59.84	0.9206	1.0000	$3,085,792.55	$51,566.31
2007	6.50	$457,618.95	65.00	58.91	0.9064	1.0000	$414,766.20	$7,040.29
2006	7.50	$1,821,145.51	65.00	57.99	0.8921	1.0000	$1,624,717.48	$28,017.62
2005	8.50	$1,616,952.13	65.00	57.07	0.8780	1.0000	$1,419,654.28	$24,876.19
2004	9.50	$3,052,092.65	65.00	56.15	0.8639	1.0000	$2,636,617.44	$46,955.27
2003	10.50	$255,864.77	65.00	55.24	0.8498	1.0000	$217,444.05	$3,936.38
2002	11.50	$1,443,116.83	65.00	54.33	0.8358	1.0000	$1,206,222.41	$22,201.80
2001	12.50	$2,392,242.42	65.00	53.43	0.8219	1.0000	$1,966,289.58	$36,803.73
2000	13.50	$256,023.11	65.00	52.53	0.8081	1.0000	$206,889.29	$3,938.82
1999	14.50	$330,834.47	65.00	51.63	0.7943	1.0000	$262,786.40	$5,089.76
1998	15.50	$497,385.14	65.00	50.74	0.7806	1.0000	$388,255.92	$7,652.08
1997	16.50	$272,294.69	65.00	49.85	0.7670	1.0000	$208,841.78	$4,189.15
1996	17.50	$58,164.94	65.00	48.97	0.7534	1.0000	$43,821.74	$894.85
1995	18.50	$852,897.69	65.00	48.10	0.7399	1.0000	$631,085.59	$13,121.50
1994	19.50	$422,225.73	65.00	47.22	0.7265	1.0000	$306,756.42	$6,495.78
1993	20.50	$1,585,378.89	65.00	46.36	0.7132	1.0000	$1,130,671.62	$24,390.44
1992	21.50	$1,369,384.65	65.00	45.50	0.7000	1.0000	$958,528.60	$21,067.46
1991	22.50	$1,063,802.12	65.00	44.64	0.6868	1.0000	$730,632.58	$16,366.19
1990	23.50	$1,104,984.04	65.00	43.79	0.6738	1.0000	$744,498.49	$16,999.75
1989	24.50	$684,178.32	65.00	42.95	0.6608	1.0000	$452,093.18	$10,525.82
1988	25.50	$626,096.02	65.00	42.11	0.6479	1.0000	$405,660.26	$9,632.25
1987	26.50	$670,723.67	65.00	41.28	0.6351	1.0000	$425,992.55	$10,318.83
1986	27.50	$1,052,626.77	65.00	40.46	0.6225	1.0000	$655,220.07	$16,194.26
1985	28.50	$2,259,154.72	65.00	39.64	0.6099	1.0000	$1,377,771.76	$34,756.23
1984	29.50	$445,331.68	65.00	38.83	0.5974	1.0000	$266,036.36	$6,851.26
1983	30.50	$515,299.62	65.00	38.02	0.5850	1.0000	$301,448.55	$7,927.69
1982	31.50	$156,641.29	65.00	37.23	0.5727	1.0000	$89,713.04	$2,409.87
1981	32.50	$239,500.41	65.00	36.44	0.5605	1.0000	$134,251.18	$3,684.62

Generation Arrangement Report

Account: MTED 101/6-356 Overhead Conductor
Dispersion: 65.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$99,955.79	65.00	35.65	0.5485	1.0000	$54,821.84	$1,537.78
1979	34.50	$272,890.72	65.00	34.87	0.5365	1.0000	$146,414.38	$4,198.32
1978	35.50	$146,164.49	65.00	34.10	0.5247	1.0000	$76,686.63	$2,248.68
1977	36.50	$289,305.26	65.00	33.34	0.5130	1.0000	$148,401.61	$4,450.85
1976	37.50	$7,116,472.96	65.00	32.59	0.5013	1.0000	$3,567,656.31	$109,484.20
1975	38.50	$302,604.11	65.00	31.84	0.4898	1.0000	$148,229.32	$4,655.45
1974	39.50	$653,881.30	65.00	31.10	0.4784	1.0000	$312,849.39	$10,059.71
1973	40.50	$836,896.96	65.00	30.37	0.4672	1.0000	$391,013.82	$12,875.34
1972	41.50	$368,173.81	65.00	29.64	0.4561	1.0000	$167,913.58	$5,664.21
1971	42.50	$1,370,460.03	65.00	28.93	0.4451	1.0000	$609,974.05	$21,084.00
1970	43.50	$1,971,197.83	65.00	28.22	0.4342	1.0000	$855,894.51	$30,326.12
1969	44.50	$368,621.83	65.00	27.53	0.4235	1.0000	$156,102.23	$5,671.11
1968	45.50	$2,535,345.63	65.00	26.84	0.4129	1.0000	$1,046,751.45	$39,005.32
1967	46.50	$5,826,480.53	65.00	26.15	0.4024	1.0000	$2,344,380.37	$89,638.16
1966	47.50	$623,245.59	65.00	25.49	0.3921	1.0000	$244,363.23	$9,588.39
1965	48.50	$157,818.31	65.00	24.82	0.3819	1.0000	$60,267.68	$2,427.97
1964	49.50	$375,353.29	65.00	24.17	0.3719	1.0000	$139,589.30	$5,774.67
1963	50.50	$376,244.99	65.00	23.53	0.3620	1.0000	$136,198.19	$5,788.38
1962	51.50	$174,735.60	65.00	22.90	0.3523	1.0000	$61,561.84	$2,688.24
1961	52.50	$153,576.97	65.00	22.28	0.3427	1.0000	$52,637.79	$2,362.72
1960	53.50	$105,460.51	65.00	21.67	0.3334	1.0000	$35,160.27	$1,622.47
1959	54.50	$377,376.15	65.00	21.07	0.3242	1.0000	$122,335.23	$5,805.79
1958	55.50	$53,653.32	65.00	20.49	0.3152	1.0000	$16,909.78	$825.44
1957	56.50	$299,489.01	65.00	19.91	0.3063	1.0000	$91,735.76	$4,607.52
1956	57.50	$199,336.14	65.00	19.35	0.2977	1.0000	$59,334.99	$3,066.71
1955	58.50	$141,439.95	65.00	18.80	0.2892	1.0000	$40,901.73	$2,176.00
1954	59.50	$1,170,330.78	65.00	18.26	0.2809	1.0000	$328,714.12	$18,005.09
1953	60.50	$410,641.52	65.00	17.73	0.2728	1.0000	$112,034.23	$6,317.56
1952	61.50	$94,897.16	65.00	17.22	0.2649	1.0000	$25,140.22	$1,459.96
1951	62.50	$60,679.43	65.00	16.72	0.2573	1.0000	$15,611.04	$933.53
1950	63.50	$252,698.88	65.00	16.24	0.2498	1.0000	$63,119.27	$3,887.68
1949	64.50	$103,256.74	65.00	15.76	0.2425	1.0000	$25,043.06	$1,588.57
1948	65.50	$74,358.80	65.00	15.30	0.2355	1.0000	$17,508.20	$1,143.98

Generation Arrangement Report

Account: MTED 101/6-356 Overhead Conductor
Dispersion: 65.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$9,657.36	65.00	14.86	0.2286	1.0000	$2,207.87	$148.57
1946	67.50	$329.21	65.00	14.43	0.2220	1.0000	$73.07	$5.06
1945	68.50	$5,936.44	65.00	14.01	0.2155	1.0000	$1,279.51	$91.33
1944	69.50	$111.32	65.00	13.60	0.2093	1.0000	$23.30	$1.71
1943	70.50	$44,215.74	65.00	13.21	0.2033	1.0000	$8,987.35	$680.24
1942	71.50	$11,985.90	65.00	12.83	0.1974	1.0000	$2,366.24	$184.40
1941	72.50	$126,022.16	65.00	12.47	0.1918	1.0000	$24,168.79	$1,938.80
1940	73.50	$6,139.55	65.00	12.11	0.1863	1.0000	$1,143.89	$94.45
1939	74.50	$38.44	65.00	11.77	0.1811	1.0000	$6.96	$0.59
1938	75.50	$299,996.39	65.00	11.44	0.1759	1.0000	$52,778.01	$4,615.33
		$67,409,524.29	65.00	42.87	0.6595	1.0000	$44,457,600.97	$1,037,069.60

Remaining Life Depreciation Accrual

Account: MTED 101/6-35610 Clearing & R/W
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$18,717,196.78	65.83	$230,101.31	1.229358%	1.518980%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$18,717,196.78 *		$230,101.31	1.229358%	1.518980%
Average:	$18,717,196.78		$230,101.31	1.229358%	1.518980%
Grand Total:	$18,717,196.78 *		$230,101.31	1.229358%	1.518980%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-35610 Clearing & R/W
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 80 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$18,717,196.78	$3,568,784.76	0.1907	$15,148,412.02	0.8093
Computed	$18,717,196.78	$3,314,426.26	0.1771	$15,402,770.52	0.8229
Difference		$254,358.50	0.0136	($254,358.50)	-0.0136

Generation Arrangement Report

Account: MTED 101/6-35610 Clearing & R/W
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$8,278,261.87	80.00	79.50	0.9938	1.0000	$8,226,522.73	$103,478.27
2012	1.50	$1,043,962.39	80.00	78.50	0.9813	1.0000	$1,024,388.10	$13,049.53
2011	2.50	$261,029.37	80.00	77.50	0.9688	1.0000	$252,872.20	$3,262.87
2010	3.50	$904,849.90	80.00	76.50	0.9563	1.0000	$865,262.72	$11,310.62
2009	4.50	$1,575,254.93	80.00	75.50	0.9438	1.0000	$1,486,646.84	$19,690.69
2008	5.50	$606,101.49	80.00	74.50	0.9313	1.0000	$564,432.01	$7,576.27
2007	6.50	$59,111.16	80.00	73.50	0.9188	1.0000	$54,308.38	$738.89
2006	7.50	$98,194.93	80.00	72.50	0.9063	1.0000	$88,989.16	$1,227.44
2005	8.50	$456.76	80.00	71.50	0.8938	1.0000	$408.23	$5.71
2003	10.50	$1,009.96	80.00	69.50	0.8688	1.0000	$877.40	$12.62
2002	11.50	$28,153.36	80.00	68.50	0.8563	1.0000	$24,106.31	$351.92
2001	12.50	$22,925.87	80.00	67.50	0.8438	1.0000	$19,343.70	$286.57
1999	14.50	$259,725.36	80.00	65.50	0.8188	1.0000	$212,650.14	$3,246.57
1998	15.50	$418,485.03	80.00	64.50	0.8063	1.0000	$337,403.56	$5,231.06
1996	17.50	$98,927.44	80.00	62.50	0.7813	1.0000	$77,287.06	$1,236.59
1995	18.50	$220,531.23	80.00	61.50	0.7688	1.0000	$169,533.38	$2,756.64
1994	19.50	$30,392.16	80.00	60.50	0.7563	1.0000	$22,984.07	$379.90
1993	20.50	$142,149.94	80.00	59.50	0.7438	1.0000	$105,724.02	$1,776.87
1992	21.50	$13,424.89	80.00	58.50	0.7313	1.0000	$9,816.95	$167.81
1991	22.50	$4,332.76	80.00	57.50	0.7188	1.0000	$3,114.17	$54.16
1990	23.50	$55,219.46	80.00	56.50	0.7063	1.0000	$38,998.74	$690.24
1989	24.50	$2,275.30	80.00	55.50	0.6938	1.0000	$1,578.49	$28.44
1988	25.50	$72,166.64	80.00	54.50	0.6813	1.0000	$49,163.52	$902.08
1987	26.50	$16,666.90	80.00	53.50	0.6688	1.0000	$11,145.99	$208.34
1986	27.50	$34,218.39	80.00	52.50	0.6563	1.0000	$22,455.82	$427.73
1985	28.50	$188,565.83	80.00	51.50	0.6438	1.0000	$121,389.25	$2,357.07
1984	29.50	$64,342.39	80.00	50.50	0.6313	1.0000	$40,616.13	$804.28
1983	30.50	$62,598.28	80.00	49.50	0.6188	1.0000	$38,732.69	$782.48
1982	31.50	$34,352.25	80.00	48.50	0.6063	1.0000	$20,826.05	$429.40
1981	32.50	$6,790.85	80.00	47.50	0.5938	1.0000	$4,032.07	$84.89
1980	33.50	$971.86	80.00	46.50	0.5813	1.0000	$564.89	$12.15
1979	34.50	$21,925.52	80.00	45.50	0.5688	1.0000	$12,470.14	$274.07
1977	36.50	$30,111.22	80.00	43.50	0.5438	1.0000	$16,372.98	$376.39

Generation Arrangement Report

Account: MTED 101/6-35610 Clearing & R/W
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1976	37.50	$737,939.67	80.00	42.50	0.5313	1.0000	$392,030.45	$9,224.25
1975	38.50	$31,289.83	80.00	41.50	0.5188	1.0000	$16,231.60	$391.12
1974	39.50	$55,794.91	80.00	40.50	0.5063	1.0000	$28,246.17	$697.44
1973	40.50	$125,048.94	80.00	39.50	0.4938	1.0000	$61,742.91	$1,563.11
1972	41.50	$65,783.12	80.00	38.50	0.4813	1.0000	$31,658.13	$822.29
1971	42.50	$143,787.47	80.00	37.50	0.4688	1.0000	$67,400.38	$1,797.34
1970	43.50	$101,274.33	80.00	36.50	0.4563	1.0000	$46,206.41	$1,265.93
1969	44.50	$70,675.51	80.00	35.50	0.4438	1.0000	$31,362.26	$883.44
1968	45.50	$270,594.97	80.00	34.50	0.4313	1.0000	$116,694.08	$3,382.44
1967	46.50	$470,987.29	80.00	33.50	0.4188	1.0000	$197,225.93	$5,887.34
1966	47.50	$177,339.10	80.00	32.50	0.4063	1.0000	$72,044.01	$2,216.74
1965	48.50	$32,039.11	80.00	31.50	0.3938	1.0000	$12,615.40	$400.49
1964	49.50	$22,382.62	80.00	30.50	0.3813	1.0000	$8,533.37	$279.78
1963	50.50	$82,234.40	80.00	29.50	0.3688	1.0000	$30,323.94	$1,027.93
1962	51.50	$16,285.45	80.00	28.50	0.3563	1.0000	$5,801.69	$203.57
1961	52.50	$32,615.71	80.00	27.50	0.3438	1.0000	$11,211.65	$407.70
1960	53.50	$2,935.48	80.00	26.50	0.3313	1.0000	$972.38	$36.69
1959	54.50	$41,626.98	80.00	25.50	0.3188	1.0000	$13,268.60	$520.34
1958	55.50	$11,932.37	80.00	24.50	0.3063	1.0000	$3,654.29	$149.15
1957	56.50	$108,802.21	80.00	23.50	0.2938	1.0000	$31,960.65	$1,360.03
1956	57.50	$48,676.84	80.00	22.50	0.2813	1.0000	$13,690.36	$608.46
1955	58.50	$18,866.27	80.00	21.50	0.2688	1.0000	$5,070.31	$235.83
1954	59.50	$526,319.80	80.00	20.50	0.2563	1.0000	$134,869.45	$6,579.00
1953	60.50	$302,303.82	80.00	19.50	0.2438	1.0000	$73,686.56	$3,778.80
1952	61.50	$42,866.04	80.00	18.50	0.2313	1.0000	$9,912.77	$535.83
1951	62.50	$10,285.05	80.00	17.50	0.2188	1.0000	$2,249.85	$128.56
1950	63.50	$137,928.94	80.00	16.50	0.2063	1.0000	$28,447.84	$1,724.11
1949	64.50	$20,188.04	80.00	15.50	0.1938	1.0000	$3,911.43	$252.35
1948	65.50	$32,872.94	80.00	14.50	0.1813	1.0000	$5,958.22	$410.91
1947	66.50	$2,694.11	80.00	13.50	0.1688	1.0000	$454.63	$33.68
1945	68.50	$807.20	80.00	11.50	0.1438	1.0000	$116.04	$10.09
1944	69.50	$415.00	80.00	10.50	0.1313	1.0000	$54.47	$5.19
1943	70.50	$20,993.16	80.00	9.50	0.1188	1.0000	$2,492.94	$262.41

Generation Arrangement Report

Account: MTED 101/6-35610 Clearing & R/W
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1942	71.50	$10,175.63	80.00	8.50	0.1063	1.0000	$1,081.16	$127.20
1941	72.50	$15,192.62	80.00	7.50	0.0938	1.0000	$1,424.31	$189.91
1940	73.50	$3,468.29	80.00	6.50	0.0813	1.0000	$281.80	$43.35
1938	75.50	$264,287.87	80.00	4.50	0.0563	1.0000	$14,866.19	$3,303.60
		$18,717,196.78	80.00	65.83	0.8229	1.0000	$15,402,770.52	$233,964.96

Remaining Life Depreciation Accrual

Account: MTED 101/6-358 Undergound Conductor
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 40.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$1,190,918.01	37.71	$29,947.52	2.514658%	2.651792%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($12,318.15)	0.50	($153.98)	1.250025%	
Total:	$1,190,918.01 *		$29,793.54	2.501729%	2.638157%
Average:	$1,184,758.94		$29,793.54	2.514734%	2.652624%
Grand Total:	$1,190,918.01 *		$29,793.54	2.501729%	2.638157%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-358 Undergound Conductor
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 40 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$1,190,918.01	$61,586.53	0.0517	$1,129,331.48	0.9483
Computed	$1,190,918.01	$68,169.48	0.0572	$1,122,748.53	0.9428
Difference		($6,582.95)	-0.0055	$6,582.95	0.0055

Generation Arrangement Report

Account: MTED 101/6-358 Undergound Conductor
Dispersion: 40.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$182,015.94	40.00	39.69	0.9922	1.0000	$180,602.64	$4,550.40
2012	1.50	$535,384.20	40.00	39.07	0.9767	1.0000	$522,931.16	$13,384.61
2011	2.50	$141,676.35	40.00	38.45	0.9613	1.0000	$136,195.35	$3,541.91
2008	5.50	$1,952.96	40.00	36.61	0.9153	1.0000	$1,787.58	$48.82
2007	6.50	$1,398.22	40.00	36.00	0.9001	1.0000	$1,258.53	$34.96
2005	8.50	$137,998.55	40.00	34.79	0.8698	1.0000	$120,027.85	$3,449.96
2003	10.50	$190,491.79	40.00	33.59	0.8396	1.0000	$159,945.42	$4,762.29
		$1,190,918.01	40.00	37.71	0.9428	1.0000	$1,122,748.53	$29,772.95

Remaining Life Depreciation Accrual

Account: MTED 101/6-359 Roads & Trails
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 50.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$746,971.13	13.95	$16,811.84	2.250668%	7.168727%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$746,971.13 *		$16,811.84	2.250668%	7.168727%
Average:	$746,971.13		$16,811.84	2.250668%	7.168727%
Grand Total:	$746,971.13 *		$16,811.84	2.250668%	7.168727%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-359 Roads & Trails
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 50 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$746,971.13	$512,454.78	0.6860	$234,516.35	0.3140
Computed	$746,971.13	$538,573.99	0.7210	$208,397.14	0.2790
Difference		($26,119.21)	-0.0350	$26,119.21	0.0350

Generation Arrangement Report

Account: MTED 101/6-359 Roads & Trails
Dispersion: 50.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2012	1.50	$31,423.33	50.00	48.50	0.9700	1.0000	$30,480.63	$628.47
1993	20.50	$2,946.76	50.00	29.50	0.5900	1.0000	$1,738.59	$58.94
1983	30.50	$5,088.94	50.00	19.50	0.3900	1.0000	$1,984.69	$101.78
1976	37.50	$659,224.35	50.00	12.50	0.2500	1.0000	$164,806.09	$13,184.49
1975	38.50	$1,494.25	50.00	11.50	0.2300	1.0000	$343.68	$29.89
1974	39.50	$35,384.28	50.00	10.50	0.2100	1.0000	$7,430.70	$707.69
1973	40.50	$3,869.74	50.00	9.50	0.1900	1.0000	$735.25	$77.39
1972	41.50	$5,161.91	50.00	8.50	0.1700	1.0000	$877.52	$103.24
1903	110.50	$2,377.57	50.00	0.00	0.0000	0.0000	$0.00	$0.00
		$746,971.13	50.00	13.95	0.2790	1.0000	$208,397.14	$14,891.87

Remaining Life Depreciation Accrual

Account: MTED 101/6-36012 DIST Line
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$28,932,190.21	34.95	$426,318.86	1.473510%	2.861377%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($62,555.36)	0.50	($481.20)	0.769239%	
Total:	$28,932,190.21 *		$425,837.66	1.471847%	2.858147%
Average:	$28,900,912.53		$425,837.66	1.473440%	2.864160%
Grand Total:	$28,932,190.21 *		$425,837.66	1.471847%	2.858147%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-36012 DIST Line
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 65 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$28,932,190.21	$14,033,110.49	0.4850	$14,899,079.72	0.5150
Computed	$28,932,190.21	$13,376,372.07	0.4623	$15,555,818.14	0.5377
Difference		$656,738.42	0.0227	($656,738.42)	-0.0227

Generation Arrangement Report

Account: MTED 101/6-36012 DIST Line
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2011	2.50	$236,147.13	65.00	62.50	0.9615	1.0000	$227,064.55	$3,633.03
2010	3.50	$12,975.78	65.00	61.50	0.9462	1.0000	$12,277.08	$199.63
2009	4.50	$235,206.67	65.00	60.50	0.9308	1.0000	$218,923.13	$3,618.56
2007	6.50	$101,623.06	65.00	58.50	0.9000	1.0000	$91,460.75	$1,563.43
2003	10.50	$251,094.57	65.00	54.50	0.8385	1.0000	$210,533.14	$3,862.99
1998	15.50	$818,439.49	65.00	49.50	0.7615	1.0000	$623,273.15	$12,591.38
1997	16.50	$846,746.34	65.00	48.50	0.7462	1.0000	$631,803.04	$13,026.87
1996	17.50	$1,210,914.14	65.00	47.50	0.7308	1.0000	$884,898.79	$18,629.45
1995	18.50	$1,224,781.79	65.00	46.50	0.7154	1.0000	$876,190.05	$18,842.80
1994	19.50	$1,560,245.89	65.00	45.50	0.7000	1.0000	$1,092,172.12	$24,003.78
1993	20.50	$1,673,949.27	65.00	44.50	0.6846	1.0000	$1,146,011.42	$25,753.07
1992	21.50	$1,229,456.50	65.00	43.50	0.6692	1.0000	$822,790.12	$18,914.72
1991	22.50	$995,460.94	65.00	42.50	0.6538	1.0000	$650,878.31	$15,314.78
1990	23.50	$956,536.66	65.00	41.50	0.6385	1.0000	$610,711.87	$14,715.95
1989	24.50	$857,602.96	65.00	40.50	0.6231	1.0000	$534,352.61	$13,193.89
1988	25.50	$951,726.21	65.00	39.50	0.6077	1.0000	$578,356.70	$14,641.94
1987	26.50	$1,039,189.12	65.00	38.50	0.5923	1.0000	$615,519.71	$15,987.52
1986	27.50	$1,006,556.20	65.00	37.50	0.5769	1.0000	$580,705.50	$15,485.48
1985	28.50	$868,911.28	65.00	36.50	0.5615	1.0000	$487,927.10	$13,367.87
1984	29.50	$769,512.91	65.00	35.50	0.5462	1.0000	$420,272.44	$11,838.66
1983	30.50	$746,951.68	65.00	34.50	0.5308	1.0000	$396,458.97	$11,491.56
1982	31.50	$576,747.84	65.00	33.50	0.5154	1.0000	$297,246.96	$8,873.04
1981	32.50	$482,643.87	65.00	32.50	0.5000	1.0000	$241,321.94	$7,425.29
1980	33.50	$560,471.48	65.00	31.50	0.4846	1.0000	$271,613.10	$8,622.64
1979	34.50	$499,559.01	65.00	30.50	0.4692	1.0000	$234,408.46	$7,685.52
1978	35.50	$566,255.81	65.00	29.50	0.4538	1.0000	$256,993.02	$8,711.63
1977	36.50	$585,072.88	65.00	28.50	0.4385	1.0000	$256,531.96	$9,001.12
1976	37.50	$546,209.00	65.00	27.50	0.4231	1.0000	$231,088.42	$8,403.22
1975	38.50	$478,231.36	65.00	26.50	0.4077	1.0000	$194,971.25	$7,357.41
1974	39.50	$603,861.29	65.00	25.50	0.3923	1.0000	$236,899.43	$9,290.17
1973	40.50	$673,834.77	65.00	24.50	0.3769	1.0000	$253,983.87	$10,366.69
1972	41.50	$603,077.21	65.00	23.50	0.3615	1.0000	$218,035.61	$9,278.11
1971	42.50	$509,237.56	65.00	22.50	0.3462	1.0000	$176,274.54	$7,834.42

Generation Arrangement Report

Account: MTED 101/6-36012 DIST Line
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1970	43.50	$436,742.96	65.00	21.50	0.3308	1.0000	$144,461.13	$6,719.12
1969	44.50	$406,658.99	65.00	20.50	0.3154	1.0000	$128,253.99	$6,256.29
1968	45.50	$362,726.73	65.00	19.50	0.3000	1.0000	$108,818.02	$5,580.41
1967	46.50	$343,696.86	65.00	18.50	0.2846	1.0000	$97,821.41	$5,287.64
1966	47.50	$337,779.39	65.00	17.50	0.2692	1.0000	$90,940.61	$5,196.61
1965	48.50	$309,639.49	65.00	16.50	0.2538	1.0000	$78,600.79	$4,763.68
1964	49.50	$272,824.35	65.00	15.50	0.2385	1.0000	$65,058.11	$4,197.30
1963	50.50	$249,922.94	65.00	14.50	0.2231	1.0000	$55,752.04	$3,844.97
1962	51.50	$236,861.74	65.00	13.50	0.2077	1.0000	$49,194.36	$3,644.03
1961	52.50	$261,443.45	65.00	12.50	0.1923	1.0000	$50,277.59	$4,022.21
1960	53.50	$103,137.45	65.00	11.50	0.1769	1.0000	$18,247.40	$1,586.73
1959	54.50	$128,173.89	65.00	10.50	0.1615	1.0000	$20,705.01	$1,971.91
1958	55.50	$133,446.65	65.00	9.50	0.1462	1.0000	$19,503.74	$2,053.03
1957	56.50	$92,106.57	65.00	8.50	0.1308	1.0000	$12,044.71	$1,417.02
1956	57.50	$88,012.03	65.00	7.50	0.1154	1.0000	$10,155.23	$1,354.03
1955	58.50	$64,444.39	65.00	6.50	0.1000	1.0000	$6,444.44	$991.45
1954	59.50	$83,959.01	65.00	5.50	0.0846	1.0000	$7,104.22	$1,291.68
1953	60.50	$51,763.45	65.00	4.50	0.0692	1.0000	$3,583.62	$796.36
1952	61.50	$47,030.63	65.00	3.50	0.0538	1.0000	$2,532.42	$723.55
1951	62.50	$79,710.23	65.00	2.50	0.0385	1.0000	$3,065.78	$1,226.31
1950	63.50	$35,672.13	65.00	1.50	0.0231	1.0000	$823.20	$548.80
1949	64.50	$62,555.36	65.00	0.50	0.0077	1.0000	$481.20	$962.39
1948	65.50	$49,785.96	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1947	66.50	$38,497.06	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1946	67.50	$35,420.45	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1945	68.50	$23,756.40	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1944	69.50	$8,822.26	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1943	70.50	$2,530.64	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1942	71.50	$5,425.39	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1941	72.50	$14,690.00	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1940	73.50	$8,595.66	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1939	74.50	$16,059.98	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1938	75.50	$260,448.93	65.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

Account: MTED 101/6-36012 DIST Line
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1926	87.50	$618.12	65.00	0.00	0.0000	0.0000	$0.00	$0.00
		$28,932,190.21	65.00	34.95	0.5377	1.0000	$15,555,818.14	$437,962.14

Remaining Life Depreciation Accrual

Account: MTED 101/6-361 Structure/Improve
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 45.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$12,964,492.05	22.60	$314,951.35	2.429338%	4.424774%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($334,213.64)	0.50	($3,713.48)	1.111110%	
Total:	$12,964,492.05 *		$311,237.87	2.400695%	4.372603%
Average:	$12,797,385.23		$311,237.87	2.432043%	4.477726%
Grand Total:	$12,964,492.05 *		$311,237.87	2.400695%	4.372603%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-361 Structure/Improve
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 45 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$12,964,492.05	$5,846,583.26	0.4510	$7,117,908.79	0.5490
Computed	$12,964,492.05	$6,453,428.70	0.4978	$6,511,063.35	0.5022
Difference		($606,845.44)	-0.0468	$606,845.44	0.0468

Generation Arrangement Report

Account: MTED 101/6-361 Structure/Improve
Dispersion: 45.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$91,208.42	45.00	44.51	0.9891	1.0000	$90,210.31	$2,026.85
2012	1.50	$883,343.18	45.00	43.53	0.9672	1.0000	$854,396.37	$19,629.85
2011	2.50	$163,690.84	45.00	42.55	0.9455	1.0000	$154,762.12	$3,637.57
2010	3.50	$52,791.04	45.00	41.57	0.9238	1.0000	$48,766.84	$1,173.13
2009	4.50	$262,923.93	45.00	40.60	0.9022	1.0000	$237,201.02	$5,842.75
2008	5.50	$635.99	45.00	39.63	0.8806	1.0000	$560.08	$14.13
2007	6.50	$762,854.50	45.00	38.67	0.8592	1.0000	$655,468.02	$16,952.32
2006	7.50	$39,826.43	45.00	37.71	0.8379	1.0000	$33,371.27	$885.03
2005	8.50	$298,160.98	45.00	36.75	0.8167	1.0000	$243,519.80	$6,625.80
2003	10.50	$5,225.26	45.00	34.86	0.7748	1.0000	$4,048.36	$116.12
2002	11.50	$3,397.78	45.00	33.93	0.7540	1.0000	$2,561.86	$75.51
2001	12.50	$12,900.88	45.00	33.00	0.7334	1.0000	$9,461.28	$286.69
2000	13.50	$6,217.60	45.00	32.08	0.7129	1.0000	$4,432.79	$138.17
1999	14.50	$77,485.10	45.00	31.17	0.6927	1.0000	$53,672.63	$1,721.89
1998	15.50	$757,549.75	45.00	30.27	0.6726	1.0000	$509,537.20	$16,834.44
1996	17.50	$38,184.77	45.00	28.49	0.6330	1.0000	$24,172.38	$848.55
1995	18.50	$604,354.43	45.00	27.61	0.6136	1.0000	$370,815.80	$13,430.10
1994	19.50	$170,539.15	45.00	26.74	0.5943	1.0000	$101,355.24	$3,789.76
1993	20.50	$1,308,921.18	45.00	25.89	0.5753	1.0000	$752,982.82	$29,087.14
1992	21.50	$422,115.70	45.00	25.04	0.5565	1.0000	$234,900.48	$9,380.35
1991	22.50	$294,558.55	45.00	24.21	0.5379	1.0000	$158,451.87	$6,545.75
1990	23.50	$662,744.18	45.00	23.38	0.5196	1.0000	$344,375.90	$14,727.65
1989	24.50	$614,322.01	45.00	22.57	0.5016	1.0000	$308,117.59	$13,651.60
1988	25.50	$266,213.51	45.00	21.77	0.4837	1.0000	$128,772.32	$5,915.86
1987	26.50	$266,765.60	45.00	20.98	0.4662	1.0000	$124,361.08	$5,928.12
1986	27.50	$326,682.71	45.00	20.20	0.4489	1.0000	$146,651.90	$7,259.62
1985	28.50	$185,339.72	45.00	19.44	0.4319	1.0000	$80,050.35	$4,118.66
1984	29.50	$82,694.09	45.00	18.68	0.4152	1.0000	$34,330.57	$1,837.65
1983	30.50	$202,865.25	45.00	17.94	0.3987	1.0000	$80,890.25	$4,508.12
1982	31.50	$9,253.30	45.00	17.22	0.3826	1.0000	$3,540.61	$205.63
1981	32.50	$24,651.79	45.00	16.51	0.3668	1.0000	$9,043.22	$547.82
1980	33.50	$80,565.25	45.00	15.81	0.3514	1.0000	$28,308.04	$1,790.34
1979	34.50	$68,159.53	45.00	15.13	0.3362	1.0000	$22,915.39	$1,514.66

Generation Arrangement Report

Account: MTED 101/6-361 Structure/Improve
Dispersion: 45.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1978	35.50	$4,573.91	45.00	14.47	0.3214	1.0000	$1,470.28	$101.64
1977	36.50	$14,534.92	45.00	13.82	0.3071	1.0000	$4,463.13	$323.00
1976	37.50	$25,263.50	45.00	13.19	0.2931	1.0000	$7,403.80	$561.41
1975	38.50	$3,653.41	45.00	12.57	0.2794	1.0000	$1,020.81	$81.19
1974	39.50	$131,713.69	45.00	11.98	0.2663	1.0000	$35,069.20	$2,926.97
1973	40.50	$295,178.34	45.00	11.41	0.2535	1.0000	$74,834.99	$6,559.52
1972	41.50	$545,783.09	45.00	10.86	0.2412	1.0000	$131,663.43	$12,128.51
1971	42.50	$619,333.88	45.00	10.32	0.2294	1.0000	$142,076.24	$13,762.98
1970	43.50	$160,104.36	45.00	9.81	0.2180	1.0000	$34,901.93	$3,557.87
1969	44.50	$229,232.79	45.00	9.32	0.2071	1.0000	$47,475.18	$5,094.06
1968	45.50	$143,923.81	45.00	8.85	0.1967	1.0000	$28,307.41	$3,198.31
1967	46.50	$164,560.59	45.00	8.40	0.1867	1.0000	$30,727.78	$3,656.90
1966	47.50	$65,906.76	45.00	7.97	0.1772	1.0000	$11,679.60	$1,464.59
1965	48.50	$44,037.95	45.00	7.57	0.1682	1.0000	$7,406.26	$978.62
1964	49.50	$46,344.12	45.00	7.18	0.1596	1.0000	$7,395.47	$1,029.87
1963	50.50	$47,956.82	45.00	6.81	0.1514	1.0000	$7,260.46	$1,065.71
1962	51.50	$75,166.96	45.00	6.46	0.1436	1.0000	$10,794.61	$1,670.38
1961	52.50	$54,835.49	45.00	6.13	0.1362	1.0000	$7,470.84	$1,218.57
1960	53.50	$42,479.60	45.00	5.81	0.1292	1.0000	$5,486.67	$943.99
1959	54.50	$30,086.53	45.00	5.51	0.1224	1.0000	$3,682.36	$668.59
1958	55.50	$56,750.12	45.00	5.22	0.1159	1.0000	$6,576.72	$1,261.11
1957	56.50	$106,175.94	45.00	4.94	0.1097	1.0000	$11,652.16	$2,359.47
1956	57.50	$78,755.11	45.00	4.66	0.1037	1.0000	$8,163.04	$1,750.11
1955	58.50	$34,600.24	45.00	4.40	0.0977	1.0000	$3,380.14	$768.89
1954	59.50	$49,410.48	45.00	4.13	0.0918	1.0000	$4,537.75	$1,098.01
1953	60.50	$66,987.51	45.00	3.87	0.0861	1.0000	$5,764.78	$1,488.61
1952	61.50	$30,975.60	45.00	3.62	0.0805	1.0000	$2,493.33	$688.35
1951	62.50	$45,996.49	45.00	3.36	0.0747	1.0000	$3,437.91	$1,022.14
1950	63.50	$40,437.71	45.00	3.10	0.0690	1.0000	$2,789.87	$898.62
1949	64.50	$36,569.11	45.00	2.85	0.0632	1.0000	$2,312.76	$812.65
1948	65.50	$23,966.87	45.00	2.60	0.0578	1.0000	$1,386.23	$532.60
1947	66.50	$15,707.82	45.00	2.35	0.0521	1.0000	$819.16	$349.06
1946	67.50	$6,375.07	45.00	2.09	0.0465	1.0000	$296.43	$141.67

Generation Arrangement Report

Account: MTED 101/6-361 Structure/Improve
Dispersion: 45.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1945	68.50	$4,288.02	45.00	1.84	0.0409	1.0000	$175.39	$95.29
1944	69.50	$265.92	45.00	1.59	0.0354	1.0000	$9.41	$5.91
1943	70.50	$103.69	45.00	1.37	0.0305	1.0000	$3.17	$2.30
1942	71.50	$4,766.53	45.00	1.14	0.0254	1.0000	$121.02	$105.92
1941	72.50	$22,683.94	45.00	0.92	0.0204	1.0000	$462.14	$504.09
1940	73.50	$4,050.77	45.00	0.69	0.0152	1.0000	$61.69	$90.02
1939	74.50	$1,969.24	45.00	0.55	0.0122	1.0000	$24.07	$43.76
1938	75.50	$502,301.63	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1937	76.50	$4,494.55	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1936	77.50	$5.49	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1935	78.50	$514.20	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1933	80.50	$1,422.20	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1931	82.50	$2,898.93	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1930	83.50	$1,267.43	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1929	84.50	$5,511.83	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1928	85.50	$6,388.75	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1927	86.50	$3,117.19	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	87.50	$1,349.72	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1924	89.50	$2,728.95	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1923	90.50	$1,336.79	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1922	91.50	$38.82	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1912	101.50	$1,816.55	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1900	113.50	$6,649.92	45.00	0.00	0.0000	0.0000	$0.00	$0.00
		$12,964,492.05	45.00	22.60	0.5022	1.0000	$6,511,063.35	$276,058.87

Remaining Life Depreciation Accrual

Account: MTED 101/6-362 Station equipment
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 58.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$204,313,883.98	41.97	$3,184,130.84	1.558451%	2.382748%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($1,596,112.69)	0.50	($13,759.59)	0.862069%	
Total:	$204,313,883.98 *		$3,170,371.25	1.551716%	2.372452%
Average:	$203,515,827.64		$3,170,371.25	1.557801%	2.386705%
Grand Total:	$204,313,883.98 *		$3,170,371.25	1.551716%	2.372452%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-362 Station equipment
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 58 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$204,313,883.98	$70,681,179.03	0.3459	$133,632,704.95	0.6541
Computed	$204,313,883.98	$56,473,958.46	0.2764	$147,839,925.52	0.7236
Difference		$14,207,220.57	0.0695	($14,207,220.57)	-0.0695

Generation Arrangement Report

Account: MTED 101/6-362 Station equipment
Dispersion: 58.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$6,844,012.56	58.00	57.55	0.9922	1.0000	$6,790,569.65	$118,000.22
2012	1.50	$19,592,631.51	58.00	56.64	0.9766	1.0000	$19,134,497.02	$337,803.99
2011	2.50	$6,425,977.02	58.00	55.75	0.9611	1.0000	$6,176,313.14	$110,792.71
2010	3.50	$12,316,461.97	58.00	54.85	0.9457	1.0000	$11,648,155.18	$212,352.79
2009	4.50	$5,136,035.92	58.00	53.96	0.9304	1.0000	$4,778,553.89	$88,552.34
2008	5.50	$8,022,303.11	58.00	53.08	0.9152	1.0000	$7,341,697.38	$138,315.57
2007	6.50	$7,198,716.31	58.00	52.20	0.9000	1.0000	$6,478,793.58	$124,115.80
2006	7.50	$3,877,899.40	58.00	51.32	0.8849	1.0000	$3,431,569.21	$66,860.33
2005	8.50	$7,268,998.17	58.00	50.45	0.8699	1.0000	$6,323,305.84	$125,327.55
2004	9.50	$1,960,894.90	58.00	49.59	0.8550	1.0000	$1,676,584.61	$33,808.53
2003	10.50	$4,126,297.92	58.00	48.73	0.8402	1.0000	$3,466,862.30	$71,143.07
2002	11.50	$2,673,748.89	58.00	47.88	0.8255	1.0000	$2,207,053.30	$46,099.12
2001	12.50	$5,436,332.32	58.00	47.03	0.8108	1.0000	$4,407,822.99	$93,729.87
2000	13.50	$1,792,477.73	58.00	46.19	0.7963	1.0000	$1,427,339.14	$30,904.79
1999	14.50	$1,942,202.69	58.00	45.35	0.7818	1.0000	$1,518,507.21	$33,486.25
1998	15.50	$3,624,186.80	58.00	44.52	0.7675	1.0000	$2,781,566.55	$62,485.98
1997	16.50	$4,790,553.34	58.00	43.69	0.7533	1.0000	$3,608,606.34	$82,595.75
1996	17.50	$1,082,487.74	58.00	42.87	0.7391	1.0000	$800,107.73	$18,663.58
1995	18.50	$4,931,953.10	58.00	42.06	0.7251	1.0000	$3,576,157.94	$85,033.67
1994	19.50	$2,512,107.71	58.00	41.25	0.7112	1.0000	$1,786,515.72	$43,312.20
1993	20.50	$7,222,905.19	58.00	40.45	0.6974	1.0000	$5,036,942.98	$124,532.85
1992	21.50	$6,370,610.96	58.00	39.65	0.6836	1.0000	$4,355,264.27	$109,838.12
1991	22.50	$5,987,457.45	58.00	38.86	0.6700	1.0000	$4,011,830.40	$103,232.03
1990	23.50	$8,782,959.00	58.00	38.08	0.6565	1.0000	$5,766,376.36	$151,430.33
1989	24.50	$4,509,964.67	58.00	37.31	0.6432	1.0000	$2,900,821.11	$77,758.01
1988	25.50	$3,007,366.60	58.00	36.54	0.6299	1.0000	$1,894,463.91	$51,851.15
1987	26.50	$3,354,112.45	58.00	35.77	0.6168	1.0000	$2,068,825.98	$57,829.53
1986	27.50	$3,338,654.27	58.00	35.02	0.6038	1.0000	$2,015,923.35	$57,563.00
1985	28.50	$3,039,723.73	58.00	34.27	0.5909	1.0000	$1,796,236.34	$52,409.03
1984	29.50	$3,525,948.84	58.00	33.53	0.5782	1.0000	$2,038,542.20	$60,792.22
1983	30.50	$2,084,826.03	58.00	32.80	0.5655	1.0000	$1,178,982.57	$35,945.28
1982	31.50	$491,606.96	58.00	32.08	0.5530	1.0000	$271,871.31	$8,475.98
1981	32.50	$1,100,510.84	58.00	31.36	0.5407	1.0000	$594,992.87	$18,974.32

Generation Arrangement Report

Account: MTED 101/6-362 Station equipment
Dispersion: 58.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$335,552.06	58.00	30.65	0.5284	1.0000	$177,307.30	$5,785.38
1979	34.50	$701,740.81	58.00	29.95	0.5163	1.0000	$362,321.49	$12,098.98
1978	35.50	$182,283.07	58.00	29.25	0.5044	1.0000	$91,935.42	$3,142.81
1977	36.50	$362,946.30	58.00	28.57	0.4925	1.0000	$178,761.38	$6,257.69
1976	37.50	$926,242.99	58.00	27.89	0.4808	1.0000	$445,370.75	$15,969.71
1975	38.50	$430,782.13	58.00	27.22	0.4693	1.0000	$202,178.39	$7,427.28
1974	39.50	$1,868,362.89	58.00	26.56	0.4579	1.0000	$855,593.80	$32,213.15
1973	40.50	$2,237,986.93	58.00	25.91	0.4467	1.0000	$999,691.04	$38,585.98
1972	41.50	$2,099,833.90	58.00	25.26	0.4356	1.0000	$914,672.68	$36,204.03
1971	42.50	$3,610,424.64	58.00	24.63	0.4247	1.0000	$1,533,354.87	$62,248.70
1970	43.50	$1,501,742.93	58.00	24.01	0.4139	1.0000	$621,614.04	$25,892.12
1969	44.50	$3,118,756.05	58.00	23.39	0.4033	1.0000	$1,257,820.42	$53,771.66
1968	45.50	$1,276,333.30	58.00	22.79	0.3929	1.0000	$501,443.22	$22,005.75
1967	46.50	$3,511,934.07	58.00	22.19	0.3826	1.0000	$1,343,651.34	$60,550.59
1966	47.50	$1,317,333.38	58.00	21.60	0.3725	1.0000	$490,660.96	$22,712.64
1965	48.50	$655,517.62	58.00	21.03	0.3625	1.0000	$237,627.35	$11,302.03
1964	49.50	$675,959.38	58.00	20.46	0.3528	1.0000	$238,445.81	$11,654.47
1963	50.50	$827,065.31	58.00	19.90	0.3431	1.0000	$283,797.51	$14,259.75
1962	51.50	$925,951.88	58.00	19.35	0.3337	1.0000	$308,985.03	$15,964.69
1961	52.50	$784,906.21	58.00	18.82	0.3244	1.0000	$254,637.34	$13,532.87
1960	53.50	$754,704.17	58.00	18.29	0.3154	1.0000	$238,005.22	$13,012.14
1959	54.50	$788,246.93	58.00	17.77	0.3064	1.0000	$241,555.14	$13,590.46
1958	55.50	$1,097,722.31	58.00	17.27	0.2977	1.0000	$326,797.70	$18,926.25
1957	56.50	$1,685,476.94	58.00	16.77	0.2892	1.0000	$487,383.20	$29,059.95
1956	57.50	$883,657.99	58.00	16.29	0.2808	1.0000	$248,121.04	$15,235.48
1955	58.50	$869,287.46	58.00	15.81	0.2726	1.0000	$236,953.54	$14,987.71
1954	59.50	$1,460,794.95	58.00	15.34	0.2646	1.0000	$386,457.23	$25,186.12
1953	60.50	$989,349.07	58.00	14.89	0.2567	1.0000	$253,988.10	$17,057.74
1952	61.50	$350,714.22	58.00	14.44	0.2490	1.0000	$87,344.05	$6,046.80
1951	62.50	$844,811.50	58.00	14.01	0.2415	1.0000	$204,062.78	$14,565.72
1950	63.50	$684,473.32	58.00	13.58	0.2342	1.0000	$160,319.47	$11,801.26
1949	64.50	$476,444.72	58.00	13.17	0.2271	1.0000	$108,183.31	$8,214.56
1948	65.50	$277,026.00	58.00	12.76	0.2201	1.0000	$60,964.86	$4,776.31

Generation Arrangement Report

Account: MTED 101/6-362 Station equipment
Dispersion: 58.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$193,138.69	58.00	12.37	0.2132	1.0000	$41,186.04	$3,329.98
1946	67.50	$52,077.61	58.00	11.98	0.2066	1.0000	$10,757.54	$897.89
1945	68.50	$18,848.45	58.00	11.60	0.2000	1.0000	$3,770.60	$324.97
1944	69.50	$12,104.17	58.00	11.23	0.1937	1.0000	$2,344.43	$208.69
1943	70.50	$79,018.86	58.00	10.87	0.1875	1.0000	$14,814.28	$1,362.39
1942	71.50	$84,903.60	58.00	10.52	0.1814	1.0000	$15,398.66	$1,463.86
1941	72.50	$236,187.95	58.00	10.17	0.1754	1.0000	$41,431.08	$4,072.21
1940	73.50	$18,931.58	58.00	9.84	0.1696	1.0000	$3,210.78	$326.41
1939	74.50	$5,503.63	58.00	9.50	0.1639	1.0000	$901.78	$94.89
1938	75.50	$10,207.55	58.00	9.18	0.1582	1.0000	$1,615.33	$175.99
1937	76.50	$44,052.66	58.00	8.86	0.1528	1.0000	$6,729.12	$759.53
1936	77.50	$2,059.58	58.00	8.55	0.1474	1.0000	$303.50	$35.51
1935	78.50	$8,287.48	58.00	8.23	0.1420	1.0000	$1,176.53	$142.89
1934	79.50	$432.17	58.00	7.93	0.1367	1.0000	$59.08	$7.45
1933	80.50	$6,014.97	58.00	7.63	0.1315	1.0000	$791.15	$103.71
1932	81.50	$1,205.39	58.00	7.33	0.1264	1.0000	$152.39	$20.78
1931	82.50	$39,975.21	58.00	7.03	0.1212	1.0000	$4,845.97	$689.23
1930	83.50	$34,913.10	58.00	6.74	0.1162	1.0000	$4,055.58	$601.95
1929	84.50	$83,798.41	58.00	6.45	0.1112	1.0000	$9,315.28	$1,444.80
1928	85.50	$39,173.36	58.00	6.15	0.1060	1.0000	$4,154.13	$675.40
1927	86.50	$209,967.91	58.00	5.86	0.1010	1.0000	$21,214.60	$3,620.14
1926	87.50	$40,528.19	58.00	5.57	0.0961	1.0000	$3,893.53	$698.76
1925	88.50	$38,578.85	58.00	5.29	0.0912	1.0000	$3,516.47	$665.15
1924	89.50	$42,260.61	58.00	4.99	0.0860	1.0000	$3,635.90	$728.63
1923	90.50	$75,148.38	58.00	4.70	0.0811	1.0000	$6,092.98	$1,295.66
1922	91.50	$4,767.06	58.00	4.42	0.0762	1.0000	$363.15	$82.19
1921	92.50	$30,041.76	58.00	4.12	0.0711	1.0000	$2,136.52	$517.96
1920	93.50	$1,635.87	58.00	3.84	0.0662	1.0000	$108.28	$28.20
1919	94.50	$691.14	58.00	3.56	0.0613	1.0000	$42.39	$11.92
1918	95.50	$1,377.19	58.00	3.28	0.0566	1.0000	$77.94	$23.74
1917	96.50	$1,561.17	58.00	2.99	0.0516	1.0000	$80.52	$26.92
1916	97.50	$76.56	58.00	2.72	0.0468	1.0000	$3.58	$1.32
1914	99.50	$660.18	58.00	2.19	0.0378	1.0000	$24.97	$11.38

Generation Arrangement Report

Account: MTED 101/6-362 Station equipment
Dispersion: 58.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1912	101.50	$33.01	58.00	1.65	0.0285	1.0000	$0.94	$0.57
1911	102.50	$417.38	58.00	1.42	0.0245	1.0000	$10.23	$7.20
1910	103.50	$2,199.52	58.00	1.16	0.0199	1.0000	$43.81	$37.92
1907	106.50	$300.00	58.00	0.69	0.0119	1.0000	$3.57	$5.17
1906	107.50	$1,434.29	58.00	0.19	0.0033	1.0000	$4.70	$24.73
1905	108.50	$2,460.15	58.00	0.00	0.0000	0.0000	$0.00	$0.00
1900	113.50	$1,618.81	58.00	0.00	0.0000	0.0000	$0.00	$0.00
		$204,313,883.98	58.00	41.97	0.7236	1.0000	$147,839,925.52	$3,522,582.85

Remaining Life Depreciation Accrual

Account: MTED 101/6-364 Poles towers fix
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 65.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$346,857,644.42	53.28	$4,569,719.45	1.317463%	1.876922%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($2,777,956.42)	0.50	($21,368.90)	0.769231%	
Total:	$346,857,644.42 *		$4,548,350.55	1.311302%	1.868145%
Average:	$345,468,666.21		$4,548,350.55	1.316574%	1.878864%
Grand Total:	$346,857,644.42 *		$4,548,350.55	1.311302%	1.868145%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-364 Poles towers fix
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 65 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$346,857,644.42	$103,388,800.41	0.2981	$243,468,844.01	0.7019
Computed	$346,857,644.42	$62,547,884.78	0.1803	$284,309,759.64	0.8197
Difference		$40,840,915.63	0.1177	($40,840,915.63)	-0.1177

Generation Arrangement Report

Account: MTED 101/6-364 Poles towers fix
Dispersion: 65.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$9,875,032.96	65.00	64.69	0.9952	1.0000	$9,827,788.20	$151,923.58
2012	1.50	$41,842,700.40	65.00	64.07	0.9857	1.0000	$41,243,384.07	$643,733.85
2011	2.50	$12,718,571.60	65.00	63.45	0.9761	1.0000	$12,415,183.65	$195,670.33
2010	3.50	$8,081,563.91	65.00	62.83	0.9666	1.0000	$7,812,004.25	$124,331.75
2009	4.50	$9,475,697.50	65.00	62.22	0.9572	1.0000	$9,069,803.61	$145,779.96
2008	5.50	$11,407,788.08	65.00	61.60	0.9477	1.0000	$10,811,137.18	$175,504.43
2007	6.50	$6,241,999.32	65.00	60.99	0.9383	1.0000	$5,856,558.94	$96,030.76
2006	7.50	$6,890,795.15	65.00	60.37	0.9288	1.0000	$6,400,292.46	$106,012.23
2005	8.50	$7,007,515.02	65.00	59.76	0.9194	1.0000	$6,442,867.72	$107,807.92
2004	9.50	$5,037,990.03	65.00	59.15	0.9100	1.0000	$4,584,714.23	$77,507.54
2003	10.50	$4,081,737.21	65.00	58.54	0.9007	1.0000	$3,676,331.55	$62,795.96
2002	11.50	$4,077,605.54	65.00	57.94	0.8913	1.0000	$3,634,437.95	$62,732.39
2001	12.50	$7,205,283.46	65.00	57.33	0.8820	1.0000	$6,355,033.27	$110,850.51
2000	13.50	$4,895,228.71	65.00	56.72	0.8727	1.0000	$4,271,949.78	$75,311.21
1999	14.50	$6,707,790.56	65.00	56.12	0.8634	1.0000	$5,791,425.04	$103,196.78
1998	15.50	$9,843,862.90	65.00	55.52	0.8541	1.0000	$8,407,696.79	$151,444.04
1997	16.50	$7,622,805.94	65.00	54.91	0.8448	1.0000	$6,440,098.21	$117,273.94
1996	17.50	$5,483,739.57	65.00	54.31	0.8356	1.0000	$4,582,175.01	$84,365.22
1995	18.50	$8,233,542.60	65.00	53.71	0.8264	1.0000	$6,803,886.63	$126,669.89
1994	19.50	$8,918,701.74	65.00	53.11	0.8171	1.0000	$7,287,888.78	$137,210.80
1993	20.50	$9,910,879.01	65.00	52.52	0.8079	1.0000	$8,007,340.43	$152,475.06
1992	21.50	$9,725,406.67	65.00	51.92	0.7988	1.0000	$7,768,220.47	$149,621.64
1991	22.50	$13,441,696.32	65.00	51.32	0.7896	1.0000	$10,613,296.68	$206,795.33
1990	23.50	$9,822,243.22	65.00	50.73	0.7804	1.0000	$7,665,551.44	$151,111.43
1989	24.50	$10,153,463.20	65.00	50.13	0.7713	1.0000	$7,831,209.50	$156,207.13
1988	25.50	$8,599,930.89	65.00	49.54	0.7622	1.0000	$6,554,603.52	$132,306.63
1987	26.50	$8,423,649.22	65.00	48.95	0.7531	1.0000	$6,343,508.19	$129,594.60
1986	27.50	$6,814,104.84	65.00	48.36	0.7440	1.0000	$5,069,608.38	$104,832.38
1985	28.50	$5,776,107.77	65.00	47.77	0.7349	1.0000	$4,245,028.92	$88,863.20
1984	29.50	$4,128,350.69	65.00	47.18	0.7259	1.0000	$2,996,794.69	$63,513.09
1983	30.50	$4,727,410.83	65.00	46.60	0.7169	1.0000	$3,389,057.39	$72,729.40
1982	31.50	$3,252,344.00	65.00	46.02	0.7079	1.0000	$2,302,410.41	$50,036.06
1981	32.50	$2,667,049.60	65.00	45.43	0.6990	1.0000	$1,864,175.99	$41,031.53

Generation Arrangement Report

Account: MTED 101/6-364 Poles towers fix
Dispersion: 65.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$2,841,562.45	65.00	44.85	0.6900	1.0000	$1,960,784.18	$43,716.35
1979	34.50	$2,881,953.50	65.00	44.28	0.6812	1.0000	$1,963,092.27	$44,337.75
1978	35.50	$3,120,208.95	65.00	43.70	0.6723	1.0000	$2,097,747.41	$48,003.21
1977	36.50	$2,963,910.97	65.00	43.13	0.6635	1.0000	$1,966,536.43	$45,598.63
1976	37.50	$3,049,560.08	65.00	42.56	0.6547	1.0000	$1,996,571.64	$46,916.31
1975	38.50	$2,950,129.44	65.00	41.99	0.6460	1.0000	$1,905,694.60	$45,386.61
1974	39.50	$4,265,432.49	65.00	41.42	0.6373	1.0000	$2,718,174.05	$65,622.04
1973	40.50	$4,277,123.52	65.00	40.86	0.6286	1.0000	$2,688,637.24	$65,801.90
1972	41.50	$3,282,698.00	65.00	40.30	0.6200	1.0000	$2,035,202.68	$50,503.05
1971	42.50	$3,480,890.79	65.00	39.74	0.6114	1.0000	$2,128,256.68	$53,552.17
1970	43.50	$2,926,751.87	65.00	39.19	0.6029	1.0000	$1,764,464.57	$45,026.95
1969	44.50	$2,765,820.63	65.00	38.64	0.5944	1.0000	$1,643,986.16	$42,551.09
1968	45.50	$2,494,759.13	65.00	38.09	0.5859	1.0000	$1,461,798.67	$38,380.91
1967	46.50	$2,166,490.22	65.00	37.54	0.5775	1.0000	$1,251,243.92	$33,330.62
1966	47.50	$1,887,715.45	65.00	37.00	0.5692	1.0000	$1,074,509.89	$29,041.78
1965	48.50	$1,849,950.62	65.00	36.46	0.5609	1.0000	$1,037,657.29	$28,460.78
1964	49.50	$1,661,522.25	65.00	35.92	0.5527	1.0000	$918,289.84	$25,561.88
1963	50.50	$1,493,699.70	65.00	35.39	0.5445	1.0000	$813,285.83	$22,980.00
1962	51.50	$1,458,778.12	65.00	34.86	0.5364	1.0000	$782,418.65	$22,442.74
1961	52.50	$1,239,191.13	65.00	34.34	0.5283	1.0000	$654,606.98	$19,064.48
1960	53.50	$1,154,549.77	65.00	33.81	0.5202	1.0000	$600,628.29	$17,762.30
1959	54.50	$1,167,252.69	65.00	33.30	0.5122	1.0000	$597,916.52	$17,957.73
1958	55.50	$1,041,876.25	65.00	32.78	0.5043	1.0000	$525,444.39	$16,028.87
1957	56.50	$925,413.74	65.00	32.27	0.4965	1.0000	$459,422.20	$14,237.13
1956	57.50	$872,371.03	65.00	31.76	0.4886	1.0000	$426,270.56	$13,421.09
1955	58.50	$819,141.67	65.00	31.26	0.4809	1.0000	$393,899.04	$12,602.18
1954	59.50	$758,868.17	65.00	30.75	0.4731	1.0000	$359,058.10	$11,674.89
1953	60.50	$561,891.60	65.00	30.26	0.4655	1.0000	$261,564.98	$8,644.49
1952	61.50	$567,108.76	65.00	29.76	0.4579	1.0000	$259,678.40	$8,724.75
1951	62.50	$154,851.76	65.00	29.27	0.4504	1.0000	$69,740.24	$2,382.33
1950	63.50	$335,763.50	65.00	28.79	0.4429	1.0000	$148,703.34	$5,165.59
1949	64.50	$502,723.20	65.00	28.30	0.4354	1.0000	$218,908.50	$7,734.20
1948	65.50	$522,919.99	65.00	27.82	0.4281	1.0000	$223,846.60	$8,044.92

Generation Arrangement Report

Account: MTED 101/6-364 Poles towers fix
Dispersion: 65.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$308,289.26	65.00	27.35	0.4207	1.0000	$129,712.04	$4,742.91
1946	67.50	$284,603.44	65.00	26.88	0.4135	1.0000	$117,675.75	$4,378.51
1945	68.50	$164,759.31	65.00	26.41	0.4063	1.0000	$66,934.89	$2,534.76
1944	69.50	$91,326.37	65.00	25.94	0.3991	1.0000	$36,448.18	$1,405.02
1943	70.50	$473,196.14	65.00	25.48	0.3920	1.0000	$185,485.30	$7,279.94
		$346,857,644.42	65.00	53.28	0.8197	1.0000	$284,309,759.64	$5,336,271.45

Remaining Life Depreciation Accrual

Account: MTED 101/6-365 Overhead conductor
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 55.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$365,129,006.47	46.75	$6,228,296.88	1.705780%	2.138893%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($3,374,307.56)	0.50	($30,675.52)	0.909091%	
Total:	$365,129,006.47 *		$6,197,621.36	1.697379%	2.128359%
Average:	$363,441,852.69		$6,197,621.36	1.705258%	2.140762%
Grand Total:	$365,129,006.47 *		$6,197,621.36	1.697379%	2.128359%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-365 Overhead conductor
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 55 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$365,129,006.47	$73,936,495.96	0.2025	$291,192,510.51	0.7975
Computed	$365,129,006.47	$54,748,425.07	0.1499	$310,380,581.40	0.8501
Difference		$19,188,070.89	0.0526	($19,188,070.89)	-0.0526

Generation Arrangement Report

Account: MTED 101/6-365 Overhead conductor
Dispersion: 55.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$16,243,448.15	55.00	54.69	0.9943	1.0000	$16,151,655.25	$295,335.42
2012	1.50	$61,385,116.84	55.00	54.07	0.9831	1.0000	$60,346,212.69	$1,116,093.03
2011	2.50	$25,850,108.46	55.00	53.45	0.9718	1.0000	$25,121,431.37	$470,001.97
2010	3.50	$13,743,368.65	55.00	52.83	0.9606	1.0000	$13,202,056.54	$249,879.43
2009	4.50	$21,258,311.25	55.00	52.22	0.9494	1.0000	$20,182,958.43	$386,514.75
2008	5.50	$17,922,438.37	55.00	51.60	0.9383	1.0000	$16,815,734.81	$325,862.52
2007	6.50	$20,758,151.50	55.00	50.99	0.9271	1.0000	$19,245,107.51	$377,420.94
2006	7.50	$10,790,371.35	55.00	50.38	0.9160	1.0000	$9,884,061.38	$196,188.57
2005	8.50	$11,357,642.68	55.00	49.77	0.9049	1.0000	$10,277,876.37	$206,502.59
2004	9.50	$7,335,596.52	55.00	49.16	0.8939	1.0000	$6,557,117.74	$133,374.48
2003	10.50	$3,361,828.86	55.00	48.56	0.8828	1.0000	$2,967,969.86	$61,124.16
2002	11.50	$4,513,540.00	55.00	47.95	0.8718	1.0000	$3,935,051.96	$82,064.36
2001	12.50	$5,419,736.15	55.00	47.35	0.8609	1.0000	$4,665,607.51	$98,540.66
2000	13.50	$5,664,230.46	55.00	46.74	0.8499	1.0000	$4,813,962.13	$102,986.01
1999	14.50	$7,057,201.93	55.00	46.14	0.8390	1.0000	$5,920,708.52	$128,312.76
1998	15.50	$5,955,711.88	55.00	45.54	0.8280	1.0000	$4,931,561.49	$108,285.67
1997	16.50	$6,110,355.10	55.00	44.94	0.8171	1.0000	$4,993,060.83	$111,097.37
1996	17.50	$4,486,148.34	55.00	44.34	0.8063	1.0000	$3,617,036.85	$81,566.33
1995	18.50	$6,207,951.25	55.00	43.75	0.7954	1.0000	$4,937,849.39	$112,871.84
1994	19.50	$8,389,063.95	55.00	43.15	0.7846	1.0000	$6,581,974.68	$152,528.44
1993	20.50	$7,858,852.75	55.00	42.56	0.7738	1.0000	$6,081,031.41	$142,888.23
1992	21.50	$8,243,172.79	55.00	41.96	0.7630	1.0000	$6,289,530.01	$149,875.87
1991	22.50	$7,382,866.05	55.00	41.37	0.7522	1.0000	$5,553,655.98	$134,233.93
1990	23.50	$6,416,857.56	55.00	40.78	0.7415	1.0000	$4,758,207.87	$116,670.14
1989	24.50	$4,919,363.08	55.00	40.20	0.7308	1.0000	$3,595,170.03	$89,442.97
1988	25.50	$3,872,095.03	55.00	39.61	0.7202	1.0000	$2,788,577.42	$70,401.73
1987	26.50	$4,234,636.79	55.00	39.03	0.7096	1.0000	$3,004,703.38	$76,993.40
1986	27.50	$4,409,273.76	55.00	38.44	0.6990	1.0000	$3,081,936.08	$80,168.61
1985	28.50	$3,379,106.67	55.00	37.86	0.6884	1.0000	$2,326,269.56	$61,438.30
1984	29.50	$2,987,977.88	55.00	37.29	0.6779	1.0000	$2,025,661.66	$54,326.87
1983	30.50	$3,173,545.54	55.00	36.71	0.6675	1.0000	$2,118,349.07	$57,700.83
1982	31.50	$2,000,033.84	55.00	36.14	0.6571	1.0000	$1,314,241.91	$36,364.25
1981	32.50	$1,727,310.62	55.00	35.57	0.6468	1.0000	$1,117,162.11	$31,405.65

Generation Arrangement Report

Account: MTED 101/6-365 Overhead conductor
Dispersion: 55.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$1,873,569.57	55.00	35.01	0.6365	1.0000	$1,192,475.70	$34,064.90
1979	34.50	$1,532,752.63	55.00	34.44	0.6262	1.0000	$959,882.53	$27,868.23
1978	35.50	$1,452,543.14	55.00	33.88	0.6161	1.0000	$894,880.09	$26,409.88
1977	36.50	$1,559,070.20	55.00	33.33	0.6060	1.0000	$944,760.46	$28,346.73
1976	37.50	$1,677,070.25	55.00	32.78	0.5959	1.0000	$999,423.55	$30,492.19
1975	38.50	$1,427,956.46	55.00	32.23	0.5860	1.0000	$836,711.33	$25,962.84
1974	39.50	$2,477,989.48	55.00	31.68	0.5760	1.0000	$1,427,402.59	$45,054.35
1973	40.50	$2,491,987.76	55.00	31.14	0.5662	1.0000	$1,410,945.00	$45,308.87
1972	41.50	$2,292,057.40	55.00	30.60	0.5564	1.0000	$1,275,355.54	$41,673.77
1971	42.50	$2,479,126.75	55.00	30.07	0.5467	1.0000	$1,355,390.47	$45,075.03
1970	43.50	$2,155,680.36	55.00	29.54	0.5371	1.0000	$1,157,798.69	$39,194.19
1969	44.50	$1,958,753.37	55.00	29.01	0.5275	1.0000	$1,033,295.75	$35,613.70
1968	45.50	$1,744,534.55	55.00	28.49	0.5180	1.0000	$903,751.89	$31,718.81
1967	46.50	$1,870,208.66	55.00	27.98	0.5086	1.0000	$951,259.81	$34,003.79
1966	47.50	$1,348,111.57	55.00	27.46	0.4993	1.0000	$673,128.83	$24,511.12
1965	48.50	$1,170,134.71	55.00	26.95	0.4901	1.0000	$573,429.05	$21,275.18
1964	49.50	$926,142.43	55.00	26.45	0.4809	1.0000	$445,356.65	$16,838.95
1963	50.50	$1,042,903.72	55.00	25.95	0.4718	1.0000	$492,005.30	$18,961.89
1962	51.50	$916,522.52	55.00	25.45	0.4627	1.0000	$424,106.62	$16,664.05
1961	52.50	$817,012.91	55.00	24.96	0.4538	1.0000	$370,755.82	$14,854.78
1960	53.50	$694,560.54	55.00	24.47	0.4449	1.0000	$309,026.71	$12,628.37
1959	54.50	$672,726.06	55.00	23.99	0.4361	1.0000	$293,391.97	$12,231.38
1958	55.50	$644,941.82	55.00	23.51	0.4274	1.0000	$275,654.57	$11,726.21
1957	56.50	$624,554.56	55.00	23.03	0.4188	1.0000	$261,538.94	$11,355.54
1956	57.50	$461,470.37	55.00	22.56	0.4102	1.0000	$189,291.69	$8,390.37
1955	58.50	$465,515.06	55.00	22.09	0.4017	1.0000	$186,997.65	$8,463.91
1954	59.50	$437,025.74	55.00	21.63	0.3933	1.0000	$171,873.17	$7,945.92
1953	60.50	$281,477.21	55.00	21.17	0.3849	1.0000	$108,348.87	$5,117.77
1952	61.50	$198,668.21	55.00	20.72	0.3767	1.0000	$74,829.58	$3,612.15
1951	62.50	$270,438.07	55.00	20.26	0.3684	1.0000	$99,642.08	$4,917.06
1950	63.50	$170,238.40	55.00	19.82	0.3603	1.0000	$61,339.76	$3,095.24
1949	64.50	$331,488.58	55.00	19.37	0.3523	1.0000	$116,767.97	$6,027.07
1948	65.50	$266,215.78	55.00	18.93	0.3443	1.0000	$91,646.11	$4,840.29

Generation Arrangement Report

Account: MTED 101/6-365 Overhead conductor
Dispersion: 55.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$162,088.23	55.00	18.50	0.3363	1.0000	$54,512.86	$2,947.06
1946	67.50	$147,227.16	55.00	18.06	0.3284	1.0000	$48,355.61	$2,676.86
1945	68.50	$97,700.60	55.00	17.64	0.3206	1.0000	$31,326.39	$1,776.37
1944	69.50	$40,556.99	55.00	17.21	0.3129	1.0000	$12,689.76	$737.40
1943	70.50	$1,532,570.60	55.00	16.79	0.3052	1.0000	$467,740.22	$27,864.92
		$365,129,006.47	55.00	46.75	0.8501	1.0000	$310,380,581.40	$6,638,709.21

Remaining Life Depreciation Accrual

Account: MTED 101/6-36510 Clearing & R/W
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$129,000,441.71	57.45	$1,959,429.12	1.518932%	1.740643%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($111,809.97)	0.50	($860.08)	0.769234%	
Total:	$129,000,441.71 *		$1,958,569.04	1.518265%	1.739879%
Average:	$128,944,536.73		$1,958,569.04	1.518924%	1.740744%
Grand Total:	$129,000,441.71 *		$1,958,569.04	1.518265%	1.739879%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-36510 Clearing & R/W
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 65 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$129,000,441.71	$16,431,201.52	0.1274	$112,569,240.19	0.8726
Computed	$129,000,441.71	$14,983,860.17	0.1162	$114,016,581.54	0.8838
Difference		$1,447,341.35	0.0112	($1,447,341.35)	-0.0112

Generation Arrangement Report

Account: MTED 101/6-36510 Clearing & R/W
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$40,397,191.76	65.00	64.50	0.9923	1.0000	$40,086,444.13	$621,495.26
2012	1.50	$9,581,034.71	65.00	63.50	0.9769	1.0000	$9,359,933.91	$147,400.53
2011	2.50	$5,347,439.85	65.00	62.50	0.9615	1.0000	$5,141,769.09	$82,268.31
2010	3.50	$13,619,163.01	65.00	61.50	0.9462	1.0000	$12,885,823.46	$209,525.58
2009	4.50	$23,008,169.36	65.00	60.50	0.9308	1.0000	$21,415,296.10	$353,971.84
2008	5.50	$4,776,396.94	65.00	59.50	0.9154	1.0000	$4,372,240.28	$73,483.03
2007	6.50	$2,522.69	65.00	58.50	0.9000	1.0000	$2,270.42	$38.81
2006	7.50	$502,587.25	65.00	57.50	0.8846	1.0000	$444,596.41	$7,732.11
2005	8.50	$5,871,073.39	65.00	56.50	0.8692	1.0000	$5,103,317.64	$90,324.21
2003	10.50	$289,138.51	65.00	54.50	0.8385	1.0000	$242,431.52	$4,448.28
2002	11.50	$930,637.13	65.00	53.50	0.8231	1.0000	$765,985.95	$14,317.49
2001	12.50	$1,024,416.95	65.00	52.50	0.8077	1.0000	$827,413.69	$15,760.26
2000	13.50	$1,060,475.82	65.00	51.50	0.7923	1.0000	$840,223.15	$16,315.01
1999	14.50	$789,723.85	65.00	50.50	0.7769	1.0000	$613,554.68	$12,149.60
1998	15.50	$1,228,338.58	65.00	49.50	0.7615	1.0000	$935,427.07	$18,897.52
1997	16.50	$869,150.23	65.00	48.50	0.7462	1.0000	$648,519.79	$13,371.54
1996	17.50	$617,283.24	65.00	47.50	0.7308	1.0000	$451,091.60	$9,496.67
1995	18.50	$1,004,098.76	65.00	46.50	0.7154	1.0000	$718,316.81	$15,447.67
1994	19.50	$1,641,782.22	65.00	45.50	0.7000	1.0000	$1,149,247.55	$25,258.19
1993	20.50	$1,098,372.52	65.00	44.50	0.6846	1.0000	$751,962.73	$16,898.04
1992	21.50	$1,262,265.83	65.00	43.50	0.6692	1.0000	$844,747.13	$19,419.47
1991	22.50	$1,221,528.11	65.00	42.50	0.6538	1.0000	$798,691.46	$18,792.74
1990	23.50	$1,308,777.24	65.00	41.50	0.6385	1.0000	$835,603.93	$20,135.03
1989	24.50	$1,328,283.71	65.00	40.50	0.6231	1.0000	$827,622.93	$20,435.13
1988	25.50	$1,231,252.20	65.00	39.50	0.6077	1.0000	$748,222.49	$18,942.34
1987	26.50	$1,058,580.27	65.00	38.50	0.5923	1.0000	$627,005.24	$16,285.85
1986	27.50	$648,563.92	65.00	37.50	0.5769	1.0000	$374,171.49	$9,977.91
1985	28.50	$374,897.72	65.00	36.50	0.5615	1.0000	$210,519.49	$5,767.66
1984	29.50	$251,487.33	65.00	35.50	0.5462	1.0000	$137,350.77	$3,869.04
1983	30.50	$346,093.20	65.00	34.50	0.5308	1.0000	$183,695.62	$5,324.51
1982	31.50	$200,843.36	65.00	33.50	0.5154	1.0000	$103,511.58	$3,089.90
1981	32.50	$196,628.87	65.00	32.50	0.5000	1.0000	$98,314.44	$3,025.06
1980	33.50	$234,120.27	65.00	31.50	0.4846	1.0000	$113,458.28	$3,601.85

Generation Arrangement Report

Account: MTED 101/6-36510 Clearing & R/W
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1979	34.50	$190,024.02	65.00	30.50	0.4692	1.0000	$89,165.12	$2,923.45
1978	35.50	$250,510.99	65.00	29.50	0.4538	1.0000	$113,693.45	$3,854.02
1977	36.50	$249,591.37	65.00	28.50	0.4385	1.0000	$109,436.22	$3,839.87
1976	37.50	$217,645.81	65.00	27.50	0.4231	1.0000	$92,080.92	$3,348.40
1975	38.50	$126,037.32	65.00	26.50	0.4077	1.0000	$51,384.45	$1,939.04
1974	39.50	$264,472.28	65.00	25.50	0.3923	1.0000	$103,754.51	$4,068.80
1973	40.50	$273,558.19	65.00	24.50	0.3769	1.0000	$103,110.39	$4,208.59
1972	41.50	$242,676.69	65.00	23.50	0.3615	1.0000	$87,736.96	$3,733.49
1971	42.50	$188,095.19	65.00	22.50	0.3462	1.0000	$65,109.87	$2,893.77
1970	43.50	$199,854.86	65.00	21.50	0.3308	1.0000	$66,105.84	$3,074.69
1969	44.50	$167,220.44	65.00	20.50	0.3154	1.0000	$52,738.75	$2,572.62
1968	45.50	$157,352.81	65.00	19.50	0.3000	1.0000	$47,205.84	$2,420.81
1967	46.50	$147,026.94	65.00	18.50	0.2846	1.0000	$41,846.13	$2,261.95
1966	47.50	$137,922.39	65.00	17.50	0.2692	1.0000	$37,132.95	$2,121.88
1965	48.50	$112,141.95	65.00	16.50	0.2538	1.0000	$28,466.80	$1,725.26
1964	49.50	$101,255.83	65.00	15.50	0.2385	1.0000	$24,145.62	$1,557.78
1963	50.50	$105,031.57	65.00	14.50	0.2231	1.0000	$23,430.12	$1,615.87
1962	51.50	$101,482.68	65.00	13.50	0.2077	1.0000	$21,077.17	$1,561.27
1961	52.50	$112,032.35	65.00	12.50	0.1923	1.0000	$21,544.68	$1,723.57
1960	53.50	$184,164.75	65.00	11.50	0.1769	1.0000	$32,582.99	$2,833.30
1959	54.50	$219,487.04	65.00	10.50	0.1615	1.0000	$35,455.60	$3,376.72
1958	55.50	$205,720.85	65.00	9.50	0.1462	1.0000	$30,066.89	$3,164.94
1957	56.50	$154,150.38	65.00	8.50	0.1308	1.0000	$20,158.13	$2,371.54
1956	57.50	$157,112.80	65.00	7.50	0.1154	1.0000	$18,128.40	$2,417.12
1955	58.50	$114,406.64	65.00	6.50	0.1000	1.0000	$11,440.66	$1,760.10
1954	59.50	$140,496.62	65.00	5.50	0.0846	1.0000	$11,888.18	$2,161.49
1953	60.50	$94,275.28	65.00	4.50	0.0692	1.0000	$6,526.75	$1,450.39
1952	61.50	$84,341.60	65.00	3.50	0.0538	1.0000	$4,541.47	$1,297.56
1951	62.50	$142,947.05	65.00	2.50	0.0385	1.0000	$5,497.96	$2,199.19
1950	63.50	$64,472.02	65.00	1.50	0.0231	1.0000	$1,487.82	$991.88
1949	64.50	$111,809.97	65.00	0.50	0.0077	1.0000	$860.08	$1,720.15
1948	65.50	$89,249.67	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1947	66.50	$69,038.07	65.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

Account: MTED 101/6-36510 Clearing & R/W
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1946	67.50	$63,631.42	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1945	68.50	$42,550.51	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1944	69.50	$15,821.25	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1943	70.50	$380,513.31	65.00	0.00	0.0000	0.0000	$0.00	$0.00
		$129,000,441.71	65.00	57.45	0.8838	1.0000	$114,016,581.54	$1,974,455.96

Remaining Life Depreciation Accrual

Account: MTED 101/6-366 Underground condult
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 60.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$30,284,873.81	37.23	$525,668.58	1.735746%	2.686254%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($272,476.80)	0.50	($2,270.64)	0.833333%	
Total:	$30,284,873.81 *		$523,397.94	1.728249%	2.674651%
Average:	$30,148,635.41		$523,397.94	1.736058%	2.693402%
Grand Total:	$30,284,873.81 *		$523,397.94	1.728249%	2.674651%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-366 Underground conduit
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 60 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$30,284,873.81	$10,716,042.54	0.3538	$19,568,831.27	0.6462
Computed	$30,284,873.81	$11,494,847.57	0.3796	$18,790,026.24	0.6204
Difference		($778,805.03)	-0.0257	$778,805.03	0.0257

Generation Arrangement Report

Account: MTED 101/6-366 Underground conduit
Dispersion: 60.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$48,357.55	60.00	59.53	0.9921	1.0000	$47,976.41	$805.96
2012	1.50	$2,312,987.60	60.00	58.58	0.9764	1.0000	$2,258,410.32	$38,549.79
2011	2.50	$75,590.56	60.00	57.64	0.9607	1.0000	$72,623.25	$1,259.84
2010	3.50	$34,341.50	60.00	56.71	0.9451	1.0000	$32,457.34	$572.36
2009	4.50	$2,604.34	60.00	55.77	0.9296	1.0000	$2,420.89	$43.41
2008	5.50	$108,543.60	60.00	54.85	0.9141	1.0000	$99,218.30	$1,809.06
2007	6.50	$20,261.15	60.00	53.92	0.8986	1.0000	$18,207.60	$337.69
2006	7.50	$4,829.94	60.00	53.00	0.8833	1.0000	$4,266.13	$80.50
2005	8.50	$34,373.35	60.00	52.08	0.8680	1.0000	$29,835.77	$572.89
2004	9.50	$78,115.75	60.00	51.17	0.8528	1.0000	$66,613.55	$1,301.93
2003	10.50	$439,228.26	60.00	50.25	0.8376	1.0000	$367,889.61	$7,320.47
2002	11.50	$1,249,746.99	60.00	49.35	0.8225	1.0000	$1,027,943.66	$20,829.12
2001	12.50	$1,671,131.44	60.00	48.45	0.8075	1.0000	$1,349,461.65	$27,852.19
2000	13.50	$1,381,842.30	60.00	47.55	0.7926	1.0000	$1,095,221.96	$23,030.71
1999	14.50	$796,839.79	60.00	46.67	0.7778	1.0000	$619,744.92	$13,280.66
1998	15.50	$1,286,137.91	60.00	45.78	0.7630	1.0000	$981,322.61	$21,435.63
1997	16.50	$752,540.26	60.00	44.90	0.7483	1.0000	$563,143.74	$12,542.34
1996	17.50	$386,759.14	60.00	44.03	0.7338	1.0000	$283,794.18	$6,445.99
1995	18.50	$994,720.35	60.00	43.16	0.7193	1.0000	$715,496.99	$16,578.67
1994	19.50	$709,687.42	60.00	42.29	0.7049	1.0000	$500,259.78	$11,828.12
1992	21.50	$1,098,095.22	60.00	40.59	0.6765	1.0000	$742,824.32	$18,301.59
1991	22.50	$1,542,593.00	60.00	39.74	0.6624	1.0000	$1,021,795.56	$25,709.88
1989	24.50	$1,024,705.32	60.00	38.08	0.6346	1.0000	$650,273.12	$17,078.42
1988	25.50	$1,275,732.42	60.00	37.25	0.6209	1.0000	$792,042.49	$21,262.21
1986	27.50	$1,080,310.11	60.00	35.62	0.5937	1.0000	$641,432.86	$18,005.17
1985	28.50	$858,211.76	60.00	34.82	0.5804	1.0000	$498,069.92	$14,303.53
1983	30.50	$409,913.45	60.00	33.24	0.5540	1.0000	$227,086.97	$6,831.89
1982	31.50	$258,271.11	60.00	32.46	0.5410	1.0000	$139,717.65	$4,304.52
1981	32.50	$344,878.84	60.00	31.69	0.5281	1.0000	$182,139.37	$5,747.98
1980	33.50	$358,492.35	60.00	30.92	0.5154	1.0000	$184,759.41	$5,974.87
1979	34.50	$368,875.89	60.00	30.17	0.5028	1.0000	$185,467.59	$6,147.93
1978	35.50	$375,987.74	60.00	29.42	0.4903	1.0000	$184,354.11	$6,266.46
1977	36.50	$318,411.98	60.00	28.68	0.4780	1.0000	$152,194.85	$5,306.87

Generation Arrangement Report

Account: MTED 101/6-366 Underground conduit
Dispersion: 60.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1976	37.50	$200,220.80	60.00	27.95	0.4658	1.0000	$93,258.07	$3,337.01
1975	38.50	$326,678.68	60.00	27.23	0.4538	1.0000	$148,240.02	$5,444.64
1974	39.50	$551,873.19	60.00	26.51	0.4419	1.0000	$243,863.93	$9,197.89
1973	40.50	$1,260,608.36	60.00	25.81	0.4301	1.0000	$542,222.66	$21,010.14
1972	41.50	$719,301.75	60.00	25.12	0.4186	1.0000	$301,092.17	$11,988.36
1971	42.50	$489,756.50	60.00	24.43	0.4072	1.0000	$199,412.76	$8,162.61
1970	43.50	$401,908.74	60.00	23.75	0.3959	1.0000	$159,113.44	$6,698.48
1969	44.50	$379,104.07	60.00	23.09	0.3849	1.0000	$145,901.68	$6,318.40
1968	45.50	$337,500.36	60.00	22.44	0.3739	1.0000	$126,206.34	$5,625.01
1967	46.50	$820,908.41	60.00	21.79	0.3632	1.0000	$298,151.96	$13,681.81
1966	47.50	$314,916.78	60.00	21.16	0.3527	1.0000	$111,074.19	$5,248.61
1965	48.50	$192,759.46	60.00	20.54	0.3424	1.0000	$65,991.58	$3,212.66
1964	49.50	$89,303.38	60.00	19.93	0.3322	1.0000	$29,665.14	$1,488.39
1963	50.50	$106,501.00	60.00	19.34	0.3223	1.0000	$34,324.01	$1,775.02
1962	51.50	$131,123.44	60.00	18.75	0.3125	1.0000	$40,981.29	$2,185.39
1961	52.50	$138,501.46	60.00	18.18	0.3030	1.0000	$41,965.23	$2,308.36
1960	53.50	$115,227.74	60.00	17.62	0.2937	1.0000	$33,847.49	$1,920.46
1959	54.50	$94,534.84	60.00	17.08	0.2847	1.0000	$26,909.78	$1,575.58
1958	55.50	$151,043.20	60.00	16.55	0.2758	1.0000	$41,655.83	$2,517.39
1957	56.50	$142,047.37	60.00	16.03	0.2672	1.0000	$37,957.74	$2,367.46
1956	57.50	$145,856.92	60.00	15.53	0.2588	1.0000	$37,752.20	$2,430.95
1955	58.50	$135,726.49	60.00	15.04	0.2507	1.0000	$34,024.04	$2,262.11
1954	59.50	$192,246.43	60.00	14.57	0.2428	1.0000	$46,681.10	$3,204.11
1953	60.50	$38,846.78	60.00	14.11	0.2352	1.0000	$9,135.15	$647.45
1952	61.50	$99,859.43	60.00	13.67	0.2278	1.0000	$22,744.93	$1,664.32
1951	62.50	$62,754.10	60.00	13.24	0.2206	1.0000	$13,843.84	$1,045.90
1950	63.50	$39,793.91	60.00	12.82	0.2137	1.0000	$8,503.14	$663.23
1949	64.50	$40,112.04	60.00	12.42	0.2070	1.0000	$8,302.87	$668.53
1948	65.50	$16,519.99	60.00	12.03	0.2005	1.0000	$3,313.02	$275.33
1946	67.50	$11,481.88	60.00	11.30	0.1883	1.0000	$2,162.47	$191.36
1943	70.50	$834,737.92	60.00	10.30	0.1716	1.0000	$143,261.28	$13,912.30
		$30,284,873.81	60.00	37.23	0.6204	1.0000	$18,790,026.24	$504,747.90

Remaining Life Depreciation Accrual

Account: MTED 101/6-367 Undergrd conductor
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 35.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$201,130,560.96	23.70	$5,740,987.22	2.854358%	4.219500%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($2,522,869.27)	0.50	($36,040.99)	1.428571%	
Total:	$201,130,560.96 *		$5,704,946.23	2.836439%	4.193011%
Average:	$199,869,126.33		$5,704,946.23	2.854341%	4.232249%
Grand Total:	$201,130,560.96 *		$5,704,946.23	2.836439%	4.193011%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-367 Undergrd conductor
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 35 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$201,130,560.96	$65,072,091.76	0.3235	$136,058,469.20	0.6765
Computed	$201,130,560.96	$64,939,369.91	0.3229	$136,191,191.05	0.6771
Difference		$132,721.85	0.0007	($132,721.85)	-0.0007

Generation Arrangement Report

Account: MTED 101/6-367 Undergrd conductor
Dispersion: 35.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$11,843,094.83	35.00	34.51	0.9859	1.0000	$11,676,528.75	$338,374.14
2012	1.50	$24,568,395.83	35.00	33.53	0.9579	1.0000	$23,533,802.46	$701,954.17
2011	2.50	$9,033,000.89	35.00	32.55	0.9300	1.0000	$8,400,308.76	$258,085.74
2010	3.50	$7,932,666.16	35.00	31.58	0.9022	1.0000	$7,156,584.73	$226,647.60
2009	4.50	$6,058,089.71	35.00	30.61	0.8745	1.0000	$5,297,875.28	$173,088.28
2008	5.50	$7,226,398.66	35.00	29.65	0.8470	1.0000	$6,120,985.12	$206,468.53
2007	6.50	$7,324,520.80	35.00	28.69	0.8198	1.0000	$6,004,294.22	$209,272.02
2006	7.50	$12,807,291.84	35.00	27.74	0.7927	1.0000	$10,152,228.76	$365,922.62
2005	8.50	$7,984,877.11	35.00	26.80	0.7658	1.0000	$6,115,208.97	$228,139.35
2004	9.50	$7,367,881.37	35.00	25.87	0.7393	1.0000	$5,446,820.62	$210,510.90
2003	10.50	$5,297,074.59	35.00	24.95	0.7129	1.0000	$3,776,523.35	$151,344.99
2002	11.50	$3,740,839.67	35.00	24.04	0.6869	1.0000	$2,569,674.16	$106,881.13
2001	12.50	$4,447,352.81	35.00	23.14	0.6612	1.0000	$2,940,624.88	$127,067.22
2000	13.50	$4,563,695.70	35.00	22.25	0.6358	1.0000	$2,901,715.04	$130,391.31
1999	14.50	$4,628,301.73	35.00	21.38	0.6108	1.0000	$2,827,047.82	$132,237.19
1998	15.50	$7,856,763.18	35.00	20.52	0.5861	1.0000	$4,605,207.01	$224,478.95
1997	16.50	$4,717,100.26	35.00	19.66	0.5619	1.0000	$2,650,313.44	$134,774.29
1996	17.50	$2,464,207.39	35.00	18.83	0.5379	1.0000	$1,325,592.49	$70,405.93
1995	18.50	$4,587,301.85	35.00	18.01	0.5144	1.0000	$2,359,853.33	$131,065.77
1994	19.50	$5,202,565.11	35.00	17.20	0.4913	1.0000	$2,556,188.44	$148,644.72
1993	20.50	$4,097,233.72	35.00	16.40	0.4687	1.0000	$1,920,221.18	$117,063.82
1992	21.50	$4,804,094.91	35.00	15.63	0.4465	1.0000	$2,144,951.15	$137,259.85
1991	22.50	$6,867,347.51	35.00	14.87	0.4247	1.0000	$2,916,722.31	$196,209.93
1990	23.50	$6,121,610.21	35.00	14.12	0.4034	1.0000	$2,469,693.40	$174,903.15
1989	24.50	$4,584,858.96	35.00	13.39	0.3827	1.0000	$1,754,412.32	$130,995.97
1988	25.50	$3,847,940.33	35.00	12.68	0.3624	1.0000	$1,394,442.21	$109,941.15
1987	26.50	$3,447,596.72	35.00	11.99	0.3427	1.0000	$1,181,383.88	$98,502.76
1986	27.50	$2,918,335.29	35.00	11.32	0.3235	1.0000	$944,184.67	$83,381.01
1985	28.50	$2,321,005.07	35.00	10.68	0.3051	1.0000	$708,079.59	$66,314.43
1984	29.50	$1,207,885.02	35.00	10.05	0.2872	1.0000	$346,924.28	$34,511.00
1983	30.50	$942,990.05	35.00	9.45	0.2700	1.0000	$254,644.71	$26,942.57
1982	31.50	$796,128.47	35.00	8.88	0.2536	1.0000	$201,876.89	$22,746.53
1981	32.50	$727,192.70	35.00	8.32	0.2378	1.0000	$172,958.21	$20,776.93

Generation Arrangement Report

Account: MTED 101/6-367 Undergrd conductor
Dispersion: 35.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$800,439.86	35.00	7.80	0.2229	1.0000	$178,397.23	$22,869.71
1979	34.50	$917,139.31	35.00	7.30	0.2087	1.0000	$191,385.66	$26,203.98
1978	35.50	$767,734.45	35.00	6.84	0.1953	1.0000	$149,944.81	$21,935.27
1977	36.50	$765,863.76	35.00	6.39	0.1827	1.0000	$139,907.60	$21,881.82
1976	37.50	$595,853.47	35.00	5.98	0.1708	1.0000	$101,777.74	$17,024.38
1975	38.50	$507,462.83	35.00	5.59	0.1597	1.0000	$81,031.66	$14,498.94
1974	39.50	$902,689.41	35.00	5.22	0.1493	1.0000	$134,731.65	$25,791.13
1973	40.50	$823,586.47	35.00	4.88	0.1395	1.0000	$114,879.57	$23,531.04
1972	41.50	$598,099.10	35.00	4.56	0.1303	1.0000	$77,948.91	$17,088.55
1971	42.50	$618,919.85	35.00	4.26	0.1216	1.0000	$75,259.69	$17,683.42
1970	43.50	$297,628.87	35.00	3.97	0.1134	1.0000	$33,739.41	$8,503.68
1969	44.50	$217,266.76	35.00	3.69	0.1055	1.0000	$22,916.36	$6,207.62
1968	45.50	$242,709.36	35.00	3.43	0.0979	1.0000	$23,752.34	$6,934.55
1967	46.50	$221,592.71	35.00	3.17	0.0904	1.0000	$20,041.95	$6,331.22
1966	47.50	$94,043.04	35.00	2.91	0.0832	1.0000	$7,820.00	$2,686.94
1965	48.50	$103,950.36	35.00	2.66	0.0760	1.0000	$7,895.05	$2,970.01
1964	49.50	$26,200.95	35.00	2.40	0.0685	1.0000	$1,794.00	$748.60
1963	50.50	$798.93	35.00	2.14	0.0612	1.0000	$48.87	$22.83
1962	51.50	$71.49	35.00	1.89	0.0539	1.0000	$3.86	$2.04
1960	53.50	$290.52	35.00	1.39	0.0398	1.0000	$11.57	$8.30
1959	54.50	$71.49	35.00	1.16	0.0332	1.0000	$2.37	$2.04
1958	55.50	$1,038.30	35.00	0.95	0.0273	1.0000	$28.31	$29.67
1951	62.50	$31,331.46	35.00	0.00	0.0000	0.0000	$0.00	$0.00
1950	63.50	$37,279.89	35.00	0.00	0.0000	0.0000	$0.00	$0.00
1949	64.50	$52,986.72	35.00	0.00	0.0000	0.0000	$0.00	$0.00
1948	65.50	$14,692.58	35.00	0.00	0.0000	0.0000	$0.00	$0.00
1947	66.50	$10,799.70	35.00	0.00	0.0000	0.0000	$0.00	$0.00
1945	68.50	$137,596.76	35.00	0.00	0.0000	0.0000	$0.00	$0.00
1944	69.50	$6,784.11	35.00	0.00	0.0000	0.0000	$0.00	$0.00
		$201,130,560.96	35.00	23.70	0.6771	1.0000	$136,191,191.05	$5,738,259.71

Remaining Life Depreciation Accrual

Account: MTED 101/6-368 Line Transformers
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 42.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$391,129,266.21	32.02	$8,363,184.52	2.138215%	3.123374%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($4,656,959.85)	0.50	($55,440.00)	1.190476%	
Total:	$391,129,266.21 *		$8,307,744.52	2.124041%	3.102669%
Average:	$388,800,786.29		$8,307,744.52	2.136761%	3.129887%
Grand Total:	$391,129,266.21 *		$8,307,744.52	2.124041%	3.102669%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-368 Line Transformers
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 42 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$391,129,266.21	$123,368,014.23	0.3154	$267,761,251.98	0.6846
Computed	$391,129,266.21	$92,970,848.42	0.2377	$298,158,417.79	0.7623
Difference		$30,397,165.81	0.0777	($30,397,165.81)	-0.0777

Generation Arrangement Report

Account: MTED 101/6-368 Line Transformers
Dispersion: 42.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$11,041,835.78	42.00	41.51	0.9884	1.0000	$10,913,736.78	$262,900.85
2012	1.50	$40,288,666.16	42.00	40.58	0.9661	1.0000	$38,924,873.59	$959,253.96
2011	2.50	$10,704,952.26	42.00	39.69	0.9451	1.0000	$10,116,853.35	$254,879.82
2010	3.50	$12,915,130.46	42.00	38.84	0.9248	1.0000	$11,943,892.54	$307,503.11
2009	4.50	$18,916,710.73	42.00	38.02	0.9052	1.0000	$17,123,744.91	$450,397.87
2008	5.50	$19,985,244.56	42.00	37.23	0.8863	1.0000	$17,713,871.11	$475,839.16
2007	6.50	$23,372,454.70	42.00	36.46	0.8680	1.0000	$20,288,288.64	$556,487.02
2006	7.50	$18,400,547.17	42.00	35.71	0.8502	1.0000	$15,644,727.19	$438,108.27
2005	8.50	$25,267,313.13	42.00	34.98	0.8329	1.0000	$21,046,144.42	$601,602.69
2004	9.50	$17,615,280.31	42.00	34.27	0.8160	1.0000	$14,374,834.38	$419,411.44
2003	10.50	$10,118,058.61	42.00	33.58	0.7996	1.0000	$8,090,576.72	$240,906.16
2002	11.50	$8,338,362.96	42.00	32.91	0.7835	1.0000	$6,533,485.34	$198,532.45
2001	12.50	$9,617,819.24	42.00	32.25	0.7678	1.0000	$7,384,656.59	$228,995.70
2000	13.50	$10,107,328.60	42.00	31.60	0.7524	1.0000	$7,604,990.55	$240,650.68
1999	14.50	$7,095,993.54	42.00	30.97	0.7373	1.0000	$5,231,955.75	$168,952.23
1998	15.50	$7,151,882.95	42.00	30.35	0.7225	1.0000	$5,167,548.23	$170,282.93
1997	16.50	$7,494,767.60	42.00	29.74	0.7080	1.0000	$5,306,519.72	$178,446.85
1996	17.50	$5,658,654.74	42.00	29.14	0.6937	1.0000	$3,925,647.84	$134,729.87
1995	18.50	$7,232,034.50	42.00	28.55	0.6797	1.0000	$4,915,844.88	$172,191.30
1994	19.50	$7,459,425.48	42.00	27.97	0.6659	1.0000	$4,967,564.62	$177,605.37
1993	20.50	$6,736,272.53	42.00	27.40	0.6524	1.0000	$4,394,443.57	$160,387.44
1992	21.50	$5,680,699.77	42.00	26.84	0.6390	1.0000	$3,629,931.66	$135,254.76
1991	22.50	$7,235,142.28	42.00	26.28	0.6258	1.0000	$4,527,748.28	$172,265.29
1990	23.50	$8,896,555.42	42.00	25.74	0.6128	1.0000	$5,452,035.10	$211,822.75
1989	24.50	$8,504,571.79	42.00	25.20	0.6000	1.0000	$5,102,883.20	$202,489.80
1988	25.50	$8,619,695.51	42.00	24.67	0.5874	1.0000	$5,062,933.45	$205,230.85
1987	26.50	$7,784,468.00	42.00	24.15	0.5749	1.0000	$4,475,214.90	$185,344.48
1986	27.50	$6,875,403.20	42.00	23.63	0.5626	1.0000	$3,867,845.06	$163,700.08
1985	28.50	$4,688,141.93	42.00	23.12	0.5504	1.0000	$2,580,261.61	$111,622.43
1984	29.50	$5,796,977.75	42.00	22.61	0.5383	1.0000	$3,120,757.52	$138,023.28
1983	30.50	$3,590,405.58	42.00	22.11	0.5264	1.0000	$1,890,089.21	$85,485.85
1982	31.50	$2,818,421.75	42.00	21.62	0.5147	1.0000	$1,450,509.28	$67,105.28
1981	32.50	$2,353,141.82	42.00	21.13	0.5030	1.0000	$1,183,639.38	$56,027.19

Generation Arrangement Report

Account: MTED 101/6-368 Line Transformers
Dispersion: 42.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$2,980,357.22	42.00	20.64	0.4915	1.0000	$1,464,739.59	$70,960.89
1979	34.50	$3,337,266.74	42.00	20.16	0.4801	1.0000	$1,602,062.82	$79,458.73
1978	35.50	$4,085,096.72	42.00	19.69	0.4687	1.0000	$1,914,849.71	$97,264.21
1977	36.50	$2,899,138.30	42.00	19.22	0.4575	1.0000	$1,326,472.68	$69,027.10
1976	37.50	$1,832,359.26	42.00	18.75	0.4464	1.0000	$818,031.44	$43,627.60
1975	38.50	$1,237,332.53	42.00	18.29	0.4354	1.0000	$538,766.70	$29,460.30
1974	39.50	$3,726,375.49	42.00	17.83	0.4245	1.0000	$1,581,940.77	$88,723.23
1973	40.50	$3,210,549.46	42.00	17.38	0.4137	1.0000	$1,328,213.59	$76,441.65
1972	41.50	$2,425,530.18	42.00	16.92	0.4030	1.0000	$977,426.83	$57,750.72
1971	42.50	$1,917,365.58	42.00	16.48	0.3923	1.0000	$752,231.03	$45,651.56
1970	43.50	$1,806,757.48	42.00	16.03	0.3818	1.0000	$689,760.54	$43,018.04
1969	44.50	$1,590,531.27	42.00	15.59	0.3713	1.0000	$590,523.93	$37,869.79
1968	45.50	$1,262,444.73	42.00	15.16	0.3609	1.0000	$455,578.47	$30,058.21
1967	46.50	$455,572.82	42.00	14.72	0.3505	1.0000	$159,695.17	$10,846.97
1965	48.50	$227.62	42.00	13.86	0.3301	1.0000	$75.13	$5.42
		$391,129,266.21	42.00	32.02	0.7623	1.0000	$298,158,417.79	$9,312,601.58

Remaining Life Depreciation Accrual

Account: MTED 101/6-369 Services OH
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 42.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$70,598,384.18	32.86	$1,610,845.29	2.281703%	3.043675%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($1,008,511.38)	0.50	($12,006.09)	1.190476%	
Total:	$70,598,384.18 *		$1,598,839.20	2.264697%	3.020989%
Average:	$70,094,128.49		$1,598,839.20	2.280989%	3.050050%
Grand Total:	$70,598,384.18 *		$1,598,839.20	2.264697%	3.020989%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-369 Services OH
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 42 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$70,598,384.18	$17,674,025.07	0.2503	$52,924,359.11	0.7497
Computed	$70,598,384.18	$15,371,919.88	0.2177	$55,226,464.30	0.7823
Difference		$2,302,105.19	0.0326	($2,302,105.19)	-0.0326

Generation Arrangement Report

Account: MTED 101/6-369 Services OH
Dispersion: 42.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$2,852,945.87	42.00	41.69	0.9926	1.0000	$2,831,846.69	$67,927.28
2012	1.50	$14,400,200.47	42.00	41.07	0.9778	1.0000	$14,081,127.46	$342,861.92
2011	2.50	$2,351,665.22	42.00	40.45	0.9631	1.0000	$2,264,996.01	$55,992.03
2010	3.50	$1,736,795.25	42.00	39.84	0.9485	1.0000	$1,647,324.79	$41,352.27
2009	4.50	$4,430,664.44	42.00	39.22	0.9339	1.0000	$4,137,655.05	$105,492.01
2008	5.50	$1,717,500.35	42.00	38.61	0.9193	1.0000	$1,578,917.89	$40,892.87
2007	6.50	$920,696.16	42.00	38.00	0.9048	1.0000	$833,045.45	$21,921.34
2006	7.50	$1,256,490.76	42.00	37.39	0.8903	1.0000	$1,118,678.80	$29,916.45
2005	8.50	($22,289.08)	42.00	36.79	0.8759	1.0000	($19,522.90)	($530.69)
2004	9.50	$50,020.42	42.00	36.18	0.8615	1.0000	$43,092.98	$1,190.96
2003	10.50	$684,845.36	42.00	35.58	0.8472	1.0000	$580,173.02	$16,305.84
2002	11.50	$1,454,948.06	42.00	34.98	0.8328	1.0000	$1,211,749.48	$34,641.62
2001	12.50	$1,587,535.25	42.00	34.38	0.8186	1.0000	$1,299,512.80	$37,798.46
2000	13.50	$1,418,608.45	42.00	33.78	0.8043	1.0000	$1,141,033.54	$33,776.39
1999	14.50	$1,857,372.88	42.00	33.19	0.7901	1.0000	$1,467,559.88	$44,223.16
1998	15.50	$2,331,340.65	42.00	32.59	0.7760	1.0000	$1,809,039.27	$55,508.11
1997	16.50	$2,236,069.89	42.00	32.00	0.7618	1.0000	$1,703,542.05	$53,239.76
1996	17.50	$2,562,977.16	42.00	31.41	0.7478	1.0000	$1,916,489.96	$61,023.27
1995	18.50	$1,994,643.17	42.00	30.82	0.7338	1.0000	$1,463,571.22	$47,491.50
1994	19.50	$1,764,654.34	42.00	30.23	0.7198	1.0000	$1,270,189.74	$42,015.58
1993	20.50	$1,236,750.07	42.00	29.65	0.7059	1.0000	$873,016.36	$29,446.43
1992	21.50	$1,166,461.00	42.00	29.07	0.6921	1.0000	$807,268.48	$27,772.88
1991	22.50	$1,321,145.53	42.00	28.49	0.6783	1.0000	$896,149.92	$31,455.85
1990	23.50	$1,602,844.16	42.00	27.92	0.6646	1.0000	$1,065,326.93	$38,162.96
1989	24.50	$1,689,309.94	42.00	27.35	0.6511	1.0000	$1,099,863.06	$40,221.67
1988	25.50	$1,138,215.90	42.00	26.78	0.6376	1.0000	$725,692.98	$27,100.38
1987	26.50	$1,021,544.36	42.00	26.22	0.6242	1.0000	$637,641.19	$24,322.48
1986	27.50	$872,034.62	42.00	25.66	0.6109	1.0000	$532,733.48	$20,762.73
1985	28.50	$793,425.74	42.00	25.10	0.5977	1.0000	$474,249.46	$18,891.09
1984	29.50	$746,395.69	42.00	24.56	0.5847	1.0000	$436,385.43	$17,771.33
1983	30.50	$772,907.57	42.00	24.01	0.5717	1.0000	$441,861.07	$18,402.56
1982	31.50	$791,015.22	42.00	23.47	0.5589	1.0000	$442,068.50	$18,833.70
1981	32.50	$777,985.81	42.00	22.94	0.5462	1.0000	$424,898.55	$18,523.47

Generation Arrangement Report

Account: MTED 101/6-369 Services OH
Dispersion: 42.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$753,980.49	42.00	22.41	0.5336	1.0000	$402,295.35	$17,951.92
1979	34.50	$743,776.86	42.00	21.89	0.5211	1.0000	$387,578.08	$17,708.97
1978	35.50	$694,923.43	42.00	21.37	0.5088	1.0000	$353,547.28	$16,545.80
1977	36.50	$590,872.24	42.00	20.86	0.4966	1.0000	$293,401.43	$14,068.39
1976	37.50	$544,535.20	42.00	20.35	0.4845	1.0000	$263,818.33	$12,965.12
1975	38.50	$464,856.21	42.00	19.85	0.4725	1.0000	$219,657.13	$11,068.01
1974	39.50	$516,894.19	42.00	19.35	0.4607	1.0000	$238,143.20	$12,307.00
1973	40.50	$546,755.85	42.00	18.86	0.4490	1.0000	$245,517.58	$13,018.00
1972	41.50	$464,991.75	42.00	18.37	0.4375	1.0000	$203,428.71	$11,071.23
1971	42.50	$438,536.36	42.00	17.90	0.4261	1.0000	$186,852.05	$10,441.34
1970	43.50	$440,422.57	42.00	17.42	0.4148	1.0000	$182,679.73	$10,486.25
1969	44.50	$422,501.68	42.00	16.95	0.4036	1.0000	$170,531.80	$10,059.56
1968	45.50	$394,157.14	42.00	16.49	0.3926	1.0000	$154,744.33	$9,384.69
1967	46.50	$337,796.74	42.00	16.03	0.3817	1.0000	$128,933.62	$8,042.78
1966	47.50	$275,371.15	42.00	15.58	0.3709	1.0000	$102,135.30	$6,556.46
1965	48.50	$216,682.09	42.00	15.13	0.3602	1.0000	$78,057.04	$5,159.10
1964	49.50	$173,949.77	42.00	14.69	0.3497	1.0000	$60,829.19	$4,141.66
1963	50.50	$151,892.90	42.00	14.25	0.3393	1.0000	$51,530.25	$3,616.50
1962	51.50	$131,327.71	42.00	13.82	0.3289	1.0000	$43,197.46	$3,126.85
1961	52.50	$128,955.56	42.00	13.39	0.3187	1.0000	$41,099.90	$3,070.37
1960	53.50	$122,736.67	42.00	12.96	0.3086	1.0000	$37,876.29	$2,922.30
1959	54.50	$102,784.84	42.00	12.54	0.2986	1.0000	$30,689.96	$2,447.26
1958	55.50	$95,662.13	42.00	12.12	0.2887	1.0000	$27,613.06	$2,277.67
1957	56.50	$84,684.29	42.00	11.71	0.2788	1.0000	$23,612.53	$2,016.29
1956	57.50	$77,058.92	42.00	11.30	0.2691	1.0000	$20,733.14	$1,834.74
1955	58.50	$61,566.78	42.00	10.89	0.2594	1.0000	$15,968.19	$1,465.88
1954	59.50	$45,647.30	42.00	10.49	0.2498	1.0000	$11,401.01	$1,086.84
1953	60.50	$32,685.93	42.00	10.09	0.2402	1.0000	$7,850.70	$778.24
1952	61.50	$14,760.48	42.00	9.69	0.2307	1.0000	$3,404.87	$351.44
1951	62.50	$6,620.26	42.00	9.29	0.2212	1.0000	$1,464.44	$157.63
1950	63.50	$3,276.01	42.00	8.89	0.2118	1.0000	$693.73	$78.00
		$70,598,384.18	42.00	32.86	0.7823	1.0000	$55,226,464.30	$1,680,913.91

Remaining Life Depreciation Accrual

Account: MTED 101/6-369 Unground Services
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 41.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$98,458,791.81	23.86	$2,200,409.12	2.234853%	4.191419%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($1,120,878.15)	0.50	($13,669.25)	1.219513%	
Total:	$98,458,791.81 *		$2,186,739.87	2.220970%	4.165382%
Average:	$97,898,352.74		$2,186,739.87	2.233684%	4.210329%
Grand Total:	$98,458,791.81 *		$2,186,739.87	2.220970%	4.165382%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-369 Unground Services
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 41 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$98,458,791.81	$45,960,843.61	0.4668	$52,497,948.20	0.5332
Computed	$98,458,791.81	$41,164,739.80	0.4181	$57,294,052.01	0.5819
Difference		$4,796,103.81	0.0487	($4,796,103.81)	-0.0487

Generation Arrangement Report

Account: MTED 101/6-369 Unground Services
Dispersion: 41.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2008	5.50	$1,625,505.49	41.00	35.87	0.8749	1.0000	$1,422,132.65	$39,646.48
2007	6.50	$2,000,051.12	41.00	34.96	0.8526	1.0000	$1,705,186.33	$48,781.73
2006	7.50	$1,598,801.88	41.00	34.05	0.8304	1.0000	$1,327,680.10	$38,995.17
2005	8.50	($21,296.87)	41.00	33.15	0.8084	1.0000	($17,216.95)	($519.44)
2004	9.50	$11,925.99	41.00	32.25	0.7866	1.0000	$9,381.19	$290.88
2003	10.50	$1,957,392.20	41.00	31.36	0.7650	1.0000	$1,497,344.75	$47,741.27
2002	11.50	$4,023,222.91	41.00	30.49	0.7435	1.0000	$2,991,422.56	$98,127.39
2001	12.50	$4,827,011.94	41.00	29.61	0.7223	1.0000	$3,486,556.94	$117,732.00
2000	13.50	$4,867,084.44	41.00	28.75	0.7013	1.0000	$3,413,084.98	$118,709.38
1999	14.50	$5,807,132.45	41.00	27.90	0.6805	1.0000	$3,951,478.86	$141,637.38
1998	15.50	$5,576,591.19	41.00	27.05	0.6598	1.0000	$3,679,703.17	$136,014.42
1997	16.50	$4,827,031.92	41.00	26.22	0.6395	1.0000	$3,086,891.79	$117,732.49
1996	17.50	$5,607,772.54	41.00	25.39	0.6194	1.0000	$3,473,297.17	$136,774.94
1995	18.50	$4,863,313.90	41.00	24.58	0.5995	1.0000	$2,915,649.01	$118,617.41
1994	19.50	$5,969,219.97	41.00	23.78	0.5799	1.0000	$3,461,464.57	$145,590.73
1993	20.50	$5,335,054.51	41.00	22.98	0.5606	1.0000	$2,990,596.98	$130,123.28
1992	21.50	$5,033,025.48	41.00	22.20	0.5415	1.0000	$2,725,344.27	$122,756.72
1991	22.50	$5,361,154.54	41.00	21.43	0.5227	1.0000	$2,802,151.32	$130,759.87
1990	23.50	$5,762,118.88	41.00	20.67	0.5042	1.0000	$2,905,160.81	$140,539.48
1989	24.50	$4,757,342.88	41.00	19.92	0.4859	1.0000	$2,311,802.23	$116,032.75
1988	25.50	$3,492,352.48	41.00	19.19	0.4681	1.0000	$1,634,606.34	$85,179.33
1987	26.50	$2,390,642.06	41.00	18.47	0.4504	1.0000	$1,076,802.46	$58,308.34
1986	27.50	$2,066,147.73	41.00	17.76	0.4332	1.0000	$894,997.69	$50,393.85
1985	28.50	$1,676,994.53	41.00	17.06	0.4162	1.0000	$697,961.43	$40,902.31
1984	29.50	$1,309,066.20	41.00	16.38	0.3996	1.0000	$523,146.68	$31,928.44
1983	30.50	$790,189.54	41.00	15.72	0.3834	1.0000	$302,974.12	$19,272.92
1982	31.50	$642,730.46	41.00	15.07	0.3676	1.0000	$236,235.77	$15,676.35
1981	32.50	$705,828.42	41.00	14.44	0.3521	1.0000	$248,530.15	$17,215.33
1980	33.50	$703,935.45	41.00	13.82	0.3370	1.0000	$237,256.18	$17,169.16
1979	34.50	$787,433.35	41.00	13.22	0.3224	1.0000	$253,907.81	$19,205.69
1978	35.50	$644,797.29	41.00	12.64	0.3082	1.0000	$198,758.00	$15,726.76
1977	36.50	$462,258.47	41.00	12.08	0.2946	1.0000	$136,169.43	$11,274.60
1976	37.50	$459,576.81	41.00	11.54	0.2814	1.0000	$129,307.27	$11,209.19

Generation Arrangement Report

Account: MTED 101/6-369 Unground Services
Dispersion: 41.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1975	38.50	$422,332.69	41.00	11.01	0.2686	1.0000	$113,446.99	$10,300.80
1974	39.50	$414,985.42	41.00	10.51	0.2564	1.0000	$106,407.35	$10,121.60
1973	40.50	$448,956.13	41.00	10.03	0.2447	1.0000	$109,853.90	$10,950.15
1972	41.50	$280,327.11	41.00	9.57	0.2335	1.0000	$65,460.61	$6,837.25
1971	42.50	$189,175.30	41.00	9.14	0.2228	1.0000	$42,155.41	$4,614.03
1970	43.50	$167,312.88	41.00	8.72	0.2127	1.0000	$35,587.85	$4,080.80
1969	44.50	$152,860.23	41.00	8.33	0.2031	1.0000	$31,039.59	$3,728.30
1968	45.50	$149,924.70	41.00	7.95	0.1939	1.0000	$29,072.87	$3,656.70
1967	46.50	$82,651.71	41.00	7.60	0.1852	1.0000	$15,310.79	$2,015.90
1966	47.50	$72,713.94	41.00	7.26	0.1770	1.0000	$12,872.79	$1,773.51
1965	48.50	$58,402.02	41.00	6.94	0.1692	1.0000	$9,883.10	$1,424.44
1964	49.50	$17,246.36	41.00	6.64	0.1618	1.0000	$2,791.23	$420.64
1963	50.50	$8,580.03	41.00	6.34	0.1547	1.0000	$1,327.75	$209.27
1962	51.50	$11,208.16	41.00	6.07	0.1481	1.0000	$1,659.41	$273.37
1961	52.50	$7,970.39	41.00	5.80	0.1415	1.0000	$1,127.95	$194.40
1960	53.50	$10,447.20	41.00	5.54	0.1352	1.0000	$1,412.67	$254.81
1959	54.50	$9,434.45	41.00	5.30	0.1292	1.0000	$1,218.76	$230.11
1958	55.50	$6,720.49	41.00	5.05	0.1232	1.0000	$828.05	$163.91
1957	56.50	$9,284.40	41.00	4.82	0.1175	1.0000	$1,090.78	$226.45
1956	57.50	$5,793.20	41.00	4.58	0.1117	1.0000	$647.34	$141.30
1955	58.50	$4,201.42	41.00	4.36	0.1063	1.0000	$446.52	$102.47
1954	59.50	$2,829.91	41.00	4.13	0.1007	1.0000	$284.98	$69.02
1953	60.50	$1,453.15	41.00	3.91	0.0955	1.0000	$138.75	$35.44
1952	61.50	$1,356.03	41.00	3.69	0.0900	1.0000	$122.09	$33.07
1951	62.50	$619.42	41.00	3.47	0.0847	1.0000	$52.45	$15.11
1950	63.50	$360.43	41.00	3.26	0.0795	1.0000	$28.65	$8.79
1949	64.50	$234.49	41.00	3.03	0.0740	1.0000	$17.35	$5.72
		$98,458,791.81	41.00	23.86	0.5819	1.0000	$57,294,052.01	$2,401,433.95

Remaining Life Depreciation Accrual

Account: MTED-101/6-370
Scenario: Met Ed 2014 ADR Dist - Meters
Dispersion: 24.00 - O2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$65,903,176.77	19.69	$2,761,270.76	4.189890%	5.079869%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($2,270,394.51)	0.50	($47,299.89)	2.083334%	
Total:	$65,903,176.77 *		$2,713,970.87	4.118118%	4.992852%
Average:	$64,767,979.52		$2,713,970.87	4.190297%	5.099347%
Grand Total:	$65,903,176.77 *		$2,713,970.87	4.118118%	4.992852%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED-101/6-370
Scenario: Met Ed 2014 ADR Dist - Meters
Dispersion: 24 - O2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$65,903,176.77	$11,546,048.73	0.1752	$54,357,128.04	0.8248
Computed	$65,903,176.77	$11,847,337.45	0.1798	$54,055,839.32	0.8202
Difference		($301,288.72)	-0.0046	$301,288.72	0.0046

Generation Arrangement Report

Account: MTED-101/6-370
Dispersion: 24.00 - O2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$8,848,226.99	24.00	23.78	0.9908	1.0000	$8,767,151.88	$368,676.12
2012	1.50	$8,416,842.58	24.00	23.34	0.9726	1.0000	$8,186,262.05	$350,701.77
2011	2.50	$1,127,173.66	24.00	22.91	0.9545	1.0000	$1,075,916.13	$46,965.57
2010	3.50	$2,951,328.45	24.00	22.48	0.9366	1.0000	$2,764,210.02	$122,972.02
2009	4.50	$2,433,460.93	24.00	22.05	0.9188	1.0000	$2,235,905.55	$101,394.21
2008	5.50	$2,699,098.84	24.00	21.63	0.9012	1.0000	$2,432,423.31	$112,462.45
2007	6.50	$1,396,609.92	24.00	21.21	0.8838	1.0000	$1,234,280.45	$58,192.08
2006	7.50	$3,053,952.97	24.00	20.80	0.8665	1.0000	$2,646,313.44	$127,248.04
2005	8.50	$1,986,073.50	24.00	20.39	0.8495	1.0000	$1,687,153.92	$82,753.06
2004	9.50	$2,372,851.01	24.00	19.98	0.8327	1.0000	$1,975,817.47	$98,868.79
2003	10.50	$1,872,378.74	24.00	19.59	0.8161	1.0000	$1,528,104.09	$78,015.78
2002	11.50	$1,749,816.42	24.00	19.20	0.7998	1.0000	$1,399,573.18	$72,909.02
2001	12.50	$1,804,404.77	24.00	18.81	0.7839	1.0000	$1,414,406.25	$75,183.53
2000	13.50	$2,161,121.37	24.00	18.44	0.7682	1.0000	$1,660,184.11	$90,046.72
1999	14.50	$1,772,454.00	24.00	18.07	0.7529	1.0000	$1,334,510.78	$73,852.25
1998	15.50	$4,537,026.80	24.00	17.71	0.7380	1.0000	$3,348,493.35	$189,042.78
1997	16.50	$955,019.41	24.00	17.37	0.7236	1.0000	$691,054.01	$39,792.48
1996	17.50	$576,094.20	24.00	17.03	0.7097	1.0000	$408,830.99	$24,003.93
1995	18.50	$1,126,010.93	24.00	16.71	0.6963	1.0000	$784,022.23	$46,917.12
1994	19.50	$760,568.88	24.00	16.40	0.6835	1.0000	$519,852.52	$31,690.37
1993	20.50	$1,035,340.55	24.00	16.11	0.6714	1.0000	$695,128.96	$43,139.19
1992	21.50	$822,430.48	24.00	15.84	0.6600	1.0000	$542,835.25	$34,267.94
1991	22.50	$832,099.64	24.00	15.59	0.6495	1.0000	$540,411.45	$34,670.82
1990	23.50	$1,136,671.93	24.00	15.35	0.6397	1.0000	$727,172.10	$47,361.33
1989	24.50	$713,835.80	24.00	15.14	0.6309	1.0000	$450,369.68	$29,743.16
1988	25.50	$662,629.56	24.00	14.95	0.6230	1.0000	$412,833.17	$27,609.57
1987	26.50	$1,008,318.95	24.00	14.79	0.6161	1.0000	$621,189.32	$42,013.29
1986	27.50	$776,954.88	24.00	14.64	0.6101	1.0000	$473,992.02	$32,373.12
1985	28.50	$469,626.97	24.00	14.52	0.6049	1.0000	$284,072.88	$19,567.79
1984	29.50	$392,972.90	24.00	14.41	0.6005	1.0000	$235,968.05	$16,373.87
1983	30.50	$290,639.17	24.00	14.32	0.5967	1.0000	$173,427.14	$12,109.97
1982	31.50	$341,639.55	24.00	14.24	0.5934	1.0000	$202,729.49	$14,234.98
1981	32.50	$145,577.04	24.00	14.17	0.5904	1.0000	$85,948.55	$6,065.71

Generation Arrangement Report

Account: MTED-101/6-370
Dispersion: 24.00 - O2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$287,543.12	24.00	14.10	0.5875	1.0000	$168,944.94	$11,980.96
1979	34.50	$421,955.02	24.00	14.03	0.5845	1.0000	$246,646.94	$17,581.46
1978	35.50	$406,030.30	24.00	13.95	0.5812	1.0000	$235,987.86	$16,917.93
1977	36.50	$335,477.08	24.00	13.86	0.5774	1.0000	$193,714.28	$13,978.21
1976	37.50	$266,358.10	24.00	13.75	0.5731	1.0000	$152,644.30	$11,098.25
1975	38.50	$259,420.27	24.00	13.63	0.5681	1.0000	$147,365.67	$10,809.18
1974	39.50	$307,681.12	24.00	13.50	0.5623	1.0000	$173,016.84	$12,820.05
1973	40.50	$345,886.27	24.00	13.34	0.5557	1.0000	$192,200.18	$14,411.93
1972	41.50	$313,398.42	24.00	13.16	0.5482	1.0000	$171,810.36	$13,058.27
1971	42.50	$426,945.07	24.00	12.96	0.5399	1.0000	$230,511.97	$17,789.38
1970	43.50	$261,672.41	24.00	12.74	0.5308	1.0000	$138,882.70	$10,903.02
1969	44.50	$160,123.28	24.00	12.50	0.5208	1.0000	$83,384.80	$6,671.80
1968	45.50	$145,665.34	24.00	12.24	0.5100	1.0000	$74,289.99	$6,069.39
1967	46.50	$106,874.17	24.00	11.96	0.4985	1.0000	$53,273.31	$4,453.09
1966	47.50	$98,022.14	24.00	11.67	0.4862	1.0000	$47,653.88	$4,084.26
1965	48.50	$80,598.21	24.00	11.36	0.4731	1.0000	$38,134.99	$3,358.26
1964	49.50	$57,874.46	24.00	11.03	0.4595	1.0000	$26,593.52	$2,411.44
1963	50.50	$49,649.02	24.00	10.69	0.4452	1.0000	$22,106.12	$2,068.71
1962	51.50	$65,634.94	24.00	10.33	0.4304	1.0000	$28,252.19	$2,734.79
1961	52.50	$40,448.48	24.00	9.96	0.4151	1.0000	$16,788.73	$1,685.35
1960	53.50	$71,656.74	24.00	9.58	0.3992	1.0000	$28,604.62	$2,985.70
1959	54.50	$31,701.32	24.00	9.19	0.3828	1.0000	$12,136.81	$1,320.89
1958	55.50	$13,122.26	24.00	8.79	0.3661	1.0000	$4,803.82	$546.76
1957	56.50	$14,944.08	24.00	8.37	0.3489	1.0000	$5,214.18	$622.67
1956	57.50	$5,812.36	24.00	7.95	0.3314	1.0000	$1,926.18	$242.18
1955	58.50	$17,249.41	24.00	7.52	0.3135	1.0000	$5,407.95	$718.73
1954	59.50	$10,220.26	24.00	7.09	0.2953	1.0000	$3,018.20	$425.84
1953	60.50	$7,901.59	24.00	6.64	0.2768	1.0000	$2,187.38	$329.23
1952	61.50	$13,424.90	24.00	6.19	0.2581	1.0000	$3,464.60	$559.37
1951	62.50	$7,499.68	24.00	5.74	0.2391	1.0000	$1,792.93	$312.49
1950	63.50	$2,234.11	24.00	5.28	0.2198	1.0000	$491.16	$93.09
1949	64.50	$1,739.27	24.00	4.81	0.2004	1.0000	$348.56	$72.47
1948	65.50	$2,543.66	24.00	4.34	0.1808	1.0000	$459.83	$105.99

Generation Arrangement Report

Account: MTED-101/6-370
Dispersion: 24.00 - O2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$2,243.94	24.00	3.86	0.1610	1.0000	$361.20	$93.50
1946	67.50	$1,109.93	24.00	3.38	0.1410	1.0000	$156.49	$46.25
1945	68.50	$1,039.09	24.00	2.90	0.1209	1.0000	$125.59	$43.30
1944	69.50	$332.50	24.00	2.41	0.1006	1.0000	$33.46	$13.85
1943	70.50	$31,892.66	24.00	1.93	0.0802	1.0000	$2,559.01	$1,328.86
		$65,903,176.77	24.00	19.69	0.8202	1.0000	$54,055,839.32	$2,745,965.70

Remaining Life Depreciation Accrual

Account: MTED 101/6-371 Inst on cust prem
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 24.00 - O1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$3,819,894.22	16.38	$121,567.69	3.182488%	6.105248%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($133,420.45)	0.50	($2,779.59)	2.083331%	
Total:	$3,819,894.22 *		$118,788.10	3.109722%	5.965654%
Average:	$3,753,184.00		$118,788.10	3.164995%	6.172446%
Grand Total:	$3,819,894.22 *		$118,788.10	3.109722%	5.965654%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-371 Inst on cust prem
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 24 - O1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$3,819,894.22	$1,828,694.20	0.4787	$1,991,200.02	0.5213
Computed	$3,819,894.22	$1,212,919.59	0.3175	$2,606,974.63	0.6825
Difference		$615,774.61	0.1612	($615,774.61)	-0.1612

Generation Arrangement Report

Account: MTED 101/6-371 Inst on cust prem
Dispersion: 24.00 - O1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$61,422.97	24.00	23.75	0.9896	1.0000	$60,783.15	$2,559.29
2012	1.50	$383,644.70	24.00	23.25	0.9688	1.0000	$371,655.81	$15,985.20
2011	2.50	$122,536.51	24.00	22.75	0.9479	1.0000	$116,154.40	$5,105.69
2010	3.50	$111,006.24	24.00	22.25	0.9271	1.0000	$102,912.04	$4,625.26
2009	4.50	$63,572.17	24.00	21.75	0.9063	1.0000	$57,612.28	$2,648.84
2008	5.50	$76,244.37	24.00	21.25	0.8854	1.0000	$67,508.04	$3,176.85
2007	6.50	$51,764.15	24.00	20.75	0.8646	1.0000	$44,754.42	$2,156.84
2006	7.50	$185,453.68	24.00	20.25	0.8438	1.0000	$156,476.54	$7,727.24
2005	8.50	$159,358.11	24.00	19.75	0.8229	1.0000	$131,138.45	$6,639.92
2004	9.50	$221,987.78	24.00	19.25	0.8021	1.0000	$178,052.70	$9,249.49
2003	10.50	$51,832.24	24.00	18.75	0.7813	1.0000	$40,493.94	$2,159.68
2002	11.50	$24,706.97	24.00	18.25	0.7604	1.0000	$18,787.59	$1,029.46
2001	12.50	$49,205.48	24.00	17.75	0.7396	1.0000	$36,391.55	$2,050.23
2000	13.50	$50,929.37	24.00	17.25	0.7188	1.0000	$36,605.49	$2,122.06
1999	14.50	$58,052.85	24.00	16.75	0.6979	1.0000	$40,516.05	$2,418.87
1998	15.50	$298,911.90	24.00	16.25	0.6771	1.0000	$202,388.27	$12,454.66
1997	16.50	$92,766.23	24.00	15.75	0.6563	1.0000	$60,877.84	$3,865.26
1996	17.50	$143,392.96	24.00	15.25	0.6354	1.0000	$91,114.28	$5,974.71
1995	18.50	$156,216.06	24.00	14.75	0.6146	1.0000	$96,007.79	$6,509.00
1994	19.50	$140,552.09	24.00	14.25	0.5938	1.0000	$83,452.81	$5,856.34
1993	20.50	$375,806.12	24.00	13.75	0.5729	1.0000	$215,305.59	$15,658.59
1992	21.50	$226,742.59	24.00	13.25	0.5521	1.0000	$125,180.81	$9,447.61
1991	22.50	$190,074.11	24.00	12.75	0.5313	1.0000	$100,976.87	$7,919.75
1990	23.50	$152,371.35	24.00	12.25	0.5104	1.0000	$77,772.88	$6,348.81
1989	24.50	$51,744.57	24.00	11.75	0.4896	1.0000	$25,333.28	$2,156.02
1988	25.50	$18,955.86	24.00	11.25	0.4688	1.0000	$8,885.56	$789.83
1987	26.50	$13,973.37	24.00	10.75	0.4479	1.0000	$6,258.91	$582.22
1986	27.50	$16,426.93	24.00	10.25	0.4271	1.0000	$7,015.67	$684.46
1985	28.50	$21,752.74	24.00	9.75	0.4063	1.0000	$8,837.05	$906.36
1984	29.50	$15,604.80	24.00	9.25	0.3854	1.0000	$6,014.35	$650.20
1983	30.50	$14,107.60	24.00	8.75	0.3646	1.0000	$5,143.40	$587.82
1982	31.50	$14,483.03	24.00	8.25	0.3438	1.0000	$4,978.54	$603.46
1981	32.50	$17,870.03	24.00	7.75	0.3229	1.0000	$5,770.53	$744.58

Generation Arrangement Report

Account: MTED 101/6-371 Inst on cust prem
Dispersion: 24.00 - O1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$13,499.84	24.00	7.25	0.3021	1.0000	$4,078.08	$562.49
1979	34.50	$9,640.97	24.00	6.75	0.2813	1.0000	$2,711.52	$401.71
1978	35.50	$5,999.57	24.00	6.25	0.2604	1.0000	$1,562.39	$249.98
1977	36.50	$5,169.93	24.00	5.75	0.2396	1.0000	$1,238.63	$215.41
1976	37.50	$3,866.78	24.00	5.25	0.2188	1.0000	$845.86	$161.12
1975	38.50	$3,304.50	24.00	4.75	0.1979	1.0000	$654.02	$137.69
1974	39.50	$7,956.32	24.00	4.25	0.1771	1.0000	$1,408.93	$331.51
1973	40.50	$10,106.35	24.00	3.75	0.1563	1.0000	$1,579.12	$421.10
1972	41.50	$10,603.41	24.00	3.25	0.1354	1.0000	$1,435.88	$441.81
1970	43.50	$1,758.06	24.00	2.25	0.0938	1.0000	$164.82	$73.25
1966	47.50	$13,299.15	24.00	0.25	0.0104	1.0000	$138.53	$554.13
1965	48.50	$23,762.02	24.00	0.00	0.0000	0.0000	$0.00	$0.00
1964	49.50	$19,512.32	24.00	0.00	0.0000	0.0000	$0.00	$0.00
1963	50.50	$42,394.85	24.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	51.50	$15,550.22	24.00	0.00	0.0000	0.0000	$0.00	$0.00
		$3,819,894.22	24.00	16.38	0.6825	1.0000	$2,606,974.63	$154,944.78

Remaining Life Depreciation Accrual

Account: MTED 101/6-371 Meter Socket dvc 125
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 25.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$412,207.74	8.52	$13,283.73	3.222582%	11.732449%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$412,207.74 *		$13,283.73	3.222582%	11.732449%
Average:	$412,207.74		$13,283.73	3.222582%	11.732449%
Grand Total:	$412,207.74 *		$13,283.73	3.222582%	11.732449%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-371 Meter Socket dvc 125
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 25 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$412,207.74	$298,985.58	0.7253	$113,222.16	0.2747
Computed	$412,207.74	$271,671.77	0.6591	$140,535.97	0.3409
Difference		$27,313.81	0.0663	($27,313.81)	-0.0663

Generation Arrangement Report

Account: MTED 101/6-371 Meter Socket dvc 125
Dispersion: 25.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1999	14.50	$413.75	25.00	10.50	0.4200	1.0000	$173.78	$16.55
1998	15.50	$8,805.95	25.00	9.50	0.3800	1.0000	$3,346.26	$352.24
1997	16.50	$402,988.04	25.00	8.50	0.3400	1.0000	$137,015.93	$16,119.52
		$412,207.74	25.00	8.52	0.3409	1.0000	$140,535.97	$16,488.31

Remaining Life Depreciation Accrual

Account: MTED 101/6-371 Surge Suppression 2
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 10.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$276,707.92	0.00	$0.00	0.000000%	
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$276,707.92 *		$0.00	0.000000%	0.000000%
Average:	$276,707.92		$0.00	0.000000%	0.000000%
Grand Total:	$276,707.92 *		$0.00	0.000000%	

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-371 Surge Suppression 2
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 10 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$276,707.92	$276,707.92	1.0000	$0.00	0.0000
Computed	$276,707.92	$276,707.92	1.0000	$0.00	0.0000
Difference		$0.00	0.0000	$0.00	0.0000

Generation Arrangement Report

Account: MTED 101/6-371 Surge Suppression 2
Dispersion: 10.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1998	15.50	$21,188.73	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1997	16.50	$255,519.19	10.00	0.00	0.0000	0.0000	$0.00	$0.00
		$276,707.92	0.00	0.00	0.0000	1.0000	$0.00	$0.00

Remaining Life Depreciation Accrual

Account: MTED 101/6-373 Street Lighting
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 34.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$12,229,687.55	27.87	$339,160.20	2.773253%	3.588239%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($242,565.38)	0.50	($3,567.14)	1.470589%	
Total:	$12,229,687.55 *		$335,593.06	2.744085%	3.550499%
Average:	$12,108,404.86		$335,593.06	2.771571%	3.596650%
Grand Total:	$12,229,687.55 *		$335,593.06	2.744085%	3.550499%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-373 Street Lighting
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 34 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$12,229,687.55	$2,777,691.61	0.2271	$9,451,995.94	0.7729
Computed	$12,229,687.55	$2,205,363.90	0.1803	$10,024,323.65	0.8197
Difference		$572,327.71	0.0468	($572,327.71)	-0.0468

Generation Arrangement Report

Account: MTED 101/6-373 Street Lighting
Dispersion: 34.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$822,651.12	34.00	33.57	0.9874	1.0000	$812,316.16	$24,195.62
2012	1.50	$1,478,251.71	34.00	32.81	0.9651	1.0000	$1,426,627.59	$43,477.99
2011	2.50	$1,112,284.31	34.00	32.13	0.9449	1.0000	$1,051,038.30	$32,714.24
2010	3.50	$521,811.86	34.00	31.49	0.9263	1.0000	$483,361.80	$15,347.41
2009	4.50	$407,441.28	34.00	30.90	0.9089	1.0000	$370,312.58	$11,983.57
2008	5.50	$379,059.21	34.00	30.34	0.8924	1.0000	$338,266.55	$11,148.80
2007	6.50	$265,192.35	34.00	29.81	0.8767	1.0000	$232,498.07	$7,799.77
2006	7.50	$668,460.43	34.00	29.30	0.8617	1.0000	$576,038.75	$19,660.60
2005	8.50	$452,554.85	34.00	28.81	0.8474	1.0000	$383,486.08	$13,310.44
2004	9.50	$570,406.09	34.00	28.34	0.8336	1.0000	$475,467.99	$16,776.65
2003	10.50	$311,635.38	34.00	27.89	0.8202	1.0000	$255,613.21	$9,165.75
2002	11.50	$220,930.50	34.00	27.45	0.8073	1.0000	$178,364.59	$6,497.96
2001	12.50	$393,021.03	34.00	27.02	0.7948	1.0000	$312,387.21	$11,559.44
2000	13.50	$345,462.40	34.00	26.61	0.7827	1.0000	$270,384.98	$10,160.66
1999	14.50	$539,262.52	34.00	26.21	0.7708	1.0000	$415,672.88	$15,860.66
1998	15.50	$434,675.72	34.00	25.81	0.7592	1.0000	$330,020.78	$12,784.58
1997	16.50	$179,646.29	34.00	25.43	0.7479	1.0000	$134,351.86	$5,283.71
1996	17.50	$129,373.49	34.00	25.05	0.7367	1.0000	$95,307.31	$3,805.10
1995	18.50	$139,855.97	34.00	24.67	0.7257	1.0000	$101,490.35	$4,113.41
1994	19.50	$469,090.83	34.00	24.30	0.7148	1.0000	$335,323.63	$13,796.79
1993	20.50	$372,981.15	34.00	23.94	0.7042	1.0000	$262,636.24	$10,970.03
1992	21.50	$166,001.47	34.00	23.58	0.6936	1.0000	$115,143.73	$4,882.40
1991	22.50	$200,011.42	34.00	23.23	0.6833	1.0000	$136,661.43	$5,882.69
1990	23.50	$155,504.43	34.00	22.88	0.6731	1.0000	$104,662.37	$4,573.66
1989	24.50	$124,040.49	34.00	22.54	0.6630	1.0000	$82,237.73	$3,648.25
1988	25.50	$87,179.52	34.00	22.20	0.6531	1.0000	$56,935.45	$2,564.10
1987	26.50	$161,566.86	34.00	21.87	0.6433	1.0000	$103,939.00	$4,751.97
1986	27.50	$88,038.54	34.00	21.55	0.6337	1.0000	$55,789.10	$2,589.37
1985	28.50	$41,447.68	34.00	21.22	0.6242	1.0000	$25,872.05	$1,219.05
1984	29.50	$52,844.69	34.00	20.91	0.6149	1.0000	$32,491.98	$1,554.26
1983	30.50	$35,899.36	34.00	20.59	0.6056	1.0000	$21,742.44	$1,055.86
1982	31.50	$47,739.85	34.00	20.28	0.5966	1.0000	$28,480.48	$1,404.11
1981	32.50	$36,194.16	34.00	19.98	0.5876	1.0000	$21,268.37	$1,064.53

Generation Arrangement Report

Account: MTED 101/6-373 Street Lighting
Dispersion: 34.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$32,731.96	34.00	19.68	0.5788	1.0000	$18,945.17	$962.70
1979	34.50	$31,659.06	34.00	19.38	0.5701	1.0000	$18,048.21	$931.15
1978	35.50	$36,226.20	34.00	19.09	0.5615	1.0000	$20,341.02	$1,065.48
1977	36.50	$26,665.46	34.00	18.80	0.5530	1.0000	$14,747.11	$784.28
1976	37.50	$15,106.05	34.00	18.52	0.5447	1.0000	$8,228.29	$444.30
1975	38.50	$11,909.48	34.00	18.24	0.5365	1.0000	$6,389.12	$350.28
1974	39.50	$23,494.25	34.00	17.96	0.5284	1.0000	$12,413.29	$691.01
1973	40.50	$62,886.97	34.00	17.69	0.5204	1.0000	$32,723.43	$1,849.62
1972	41.50	$40,824.49	34.00	17.42	0.5125	1.0000	$20,921.06	$1,200.72
1971	42.50	$32,561.53	34.00	17.16	0.5047	1.0000	$16,432.69	$957.69
1970	43.50	$37,873.22	34.00	16.90	0.4970	1.0000	$18,822.29	$1,113.92
1969	44.50	$92,896.74	34.00	16.64	0.4894	1.0000	$45,464.26	$2,732.26
1968	45.50	$60,667.51	34.00	16.39	0.4819	1.0000	$29,237.32	$1,784.34
1967	46.50	$51,613.20	34.00	16.13	0.4745	1.0000	$24,492.12	$1,518.04
1966	47.50	$24,375.75	34.00	15.89	0.4672	1.0000	$11,389.53	$716.93
1965	48.50	$69,539.70	34.00	15.64	0.4601	1.0000	$31,992.45	$2,045.29
1964	49.50	$23,071.31	34.00	15.40	0.4530	1.0000	$10,450.63	$678.57
1963	50.50	$10,834.18	34.00	15.16	0.4460	1.0000	$4,831.64	$318.65
1962	51.50	$8,939.78	34.00	14.93	0.4390	1.0000	$3,924.56	$262.93
1961	52.50	$19,723.94	34.00	14.69	0.4322	1.0000	$8,523.76	$580.12
1960	53.50	$14,724.45	34.00	14.46	0.4254	1.0000	$6,263.82	$433.07
1959	54.50	$6,617.45	34.00	14.24	0.4187	1.0000	$2,770.95	$194.63
1958	55.50	$12,226.50	34.00	14.01	0.4121	1.0000	$5,039.15	$359.60
1957	56.50	$4,792.22	34.00	13.79	0.4056	1.0000	$1,943.96	$140.95
1956	57.50	$7,949.81	34.00	13.57	0.3992	1.0000	$3,173.61	$233.82
1955	58.50	$4,465.73	34.00	13.36	0.3929	1.0000	$1,754.40	$131.35
1954	59.50	$11,407.15	34.00	13.14	0.3866	1.0000	$4,409.71	$335.50
1953	60.50	$4,429.24	34.00	12.93	0.3804	1.0000	$1,684.87	$130.27
1952	61.50	$3,830.91	34.00	12.72	0.3743	1.0000	$1,433.73	$112.67
1951	62.50	$575.52	34.00	12.52	0.3682	1.0000	$211.92	$16.93
1943	70.50	$34,550.83	34.00	10.95	0.3221	1.0000	$11,128.53	$1,016.20
		$12,229,687.55	34.00	27.87	0.8197	1.0000	$10,024,323.65	$359,696.69

Remaining Life Depreciation Accrual

Account: MTED 101/6-38920 Land Rights
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 50.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$18,077.52	7.44	$399.75	2.211293%	13.447586%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$18,077.52 *		$399.75	2.211293%	13.447586%
Average:	$18,077.52		$399.75	2.211293%	13.447586%
Grand Total:	$18,077.52 *		$399.75	2.211293%	13.447586%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-38920 Land Rights
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 50 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$18,077.52	$15,104.89	0.8356	$2,972.63	0.1644
Computed	$18,077.52	$15,388.93	0.8513	$2,688.59	0.1487
Difference		($284.04)	-0.0157	$284.04	0.0157

Generation Arrangement Report

Account: MTED 101/6-38920 Land Rights
Dispersion: 50.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1996	17.50	$24.33	50.00	32.50	0.6500	1.0000	$15.81	$0.49
1990	23.50	$54.56	50.00	26.50	0.5300	1.0000	$28.92	$1.09
1972	41.50	$15,551.46	50.00	8.50	0.1700	1.0000	$2,643.75	$311.03
1969	44.50	$1.00	50.00	5.50	0.1100	1.0000	$0.11	$0.02
1963	50.50	$281.19	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	51.50	$1,489.00	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1949	64.50	$472.07	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1948	65.50	$203.91	50.00	0.00	0.0000	0.0000	$0.00	$0.00
		$18,077.52	50.00	7.44	0.1487	1.0000	$2,688.59	$312.63

Remaining Life Depreciation Accrual

Account: MTED 101/6-39010 Structures
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 40.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$18,513,559.38	26.29	$410,302.35	2.216226%	3.804058%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($303,216.78)	0.50	($3,790.21)	1.250000%	
Total:	$18,513,559.38 *		$406,512.14	2.195754%	3.768917%
Average:	$18,361,950.99		$406,512.14	2.213883%	3.822649%
Grand Total:	$18,513,559.38 *		$406,512.14	2.195754%	3.768917%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39010 Structures
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 40 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$18,513,559.38	$7,727,646.60	0.4174	$10,785,912.78	0.5826
Computed	$18,513,559.38	$6,346,578.37	0.3428	$12,166,981.01	0.6572
Difference		$1,381,068.23	0.0746	($1,381,068.23)	-0.0746

Generation Arrangement Report

Account: MTED 101/6-39010 Structures
Dispersion: 40.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$1,029,595.11	40.00	39.59	0.9897	1.0000	$1,018,991.36	$25,739.88
2012	1.50	$977,175.98	40.00	38.77	0.9692	1.0000	$947,090.85	$24,429.40
2011	2.50	$1,849,998.86	40.00	37.95	0.9489	1.0000	$1,755,404.69	$46,249.97
2010	3.50	$56,936.02	40.00	37.15	0.9287	1.0000	$52,874.20	$1,423.40
2009	4.50	$434,952.82	40.00	36.34	0.9086	1.0000	$395,206.76	$10,873.82
2008	5.50	$377,021.39	40.00	35.55	0.8887	1.0000	$335,055.95	$9,425.53
2007	6.50	$148,515.12	40.00	34.76	0.8689	1.0000	$129,051.36	$3,712.88
2006	7.50	$16,124.84	40.00	33.97	0.8493	1.0000	$13,695.03	$403.12
2005	8.50	$251,572.68	40.00	33.19	0.8299	1.0000	$208,769.18	$6,289.32
2004	9.50	$77,708.17	40.00	32.42	0.8105	1.0000	$62,984.17	$1,942.70
2003	10.50	$179,581.59	40.00	31.65	0.7914	1.0000	$142,114.23	$4,489.54
2002	11.50	$111,448.05	40.00	30.89	0.7723	1.0000	$86,074.76	$2,786.20
2001	12.50	$82,147.81	40.00	30.14	0.7535	1.0000	$61,895.44	$2,053.70
2000	13.50	$69,182.75	40.00	29.39	0.7347	1.0000	$50,831.21	$1,729.57
1998	15.50	$295,351.63	40.00	27.91	0.6978	1.0000	$206,095.19	$7,383.79
1997	16.50	$197,372.16	40.00	27.18	0.6796	1.0000	$134,131.90	$4,934.30
1996	17.50	$1,721,158.42	40.00	26.46	0.6615	1.0000	$1,138,624.51	$43,028.96
1995	18.50	$2,116,988.67	40.00	25.75	0.6437	1.0000	$1,362,734.26	$52,924.72
1994	19.50	$527,055.20	40.00	25.04	0.6261	1.0000	$329,968.08	$13,176.38
1993	20.50	$154,309.09	40.00	24.35	0.6086	1.0000	$93,918.29	$3,857.73
1992	21.50	$307,431.80	40.00	23.66	0.5914	1.0000	$181,816.81	$7,685.79
1991	22.50	$102,292.60	40.00	22.98	0.5744	1.0000	$58,759.88	$2,557.32
1990	23.50	$3,247,911.05	40.00	22.31	0.5577	1.0000	$1,811,223.73	$81,197.78
1989	24.50	$235,690.66	40.00	21.65	0.5412	1.0000	$127,545.39	$5,892.27
1988	25.50	$1,233,711.23	40.00	20.99	0.5249	1.0000	$647,542.77	$30,842.78
1987	26.50	$195,682.81	40.00	20.36	0.5089	1.0000	$99,579.90	$4,892.07
1986	27.50	$131,842.77	40.00	19.73	0.4931	1.0000	$65,015.55	$3,296.07
1985	28.50	$49,477.59	40.00	19.11	0.4777	1.0000	$23,634.46	$1,236.94
1984	29.50	$69,819.73	40.00	18.50	0.4625	1.0000	$32,289.94	$1,745.49
1983	30.50	$120,681.33	40.00	17.90	0.4476	1.0000	$54,016.94	$3,017.03
1982	31.50	$13,977.23	40.00	17.32	0.4330	1.0000	$6,051.91	$349.43
1981	32.50	$2,271.33	40.00	16.75	0.4187	1.0000	$951.00	$56.78
1980	33.50	$93,002.93	40.00	16.19	0.4047	1.0000	$37,637.01	$2,325.07

Generation Arrangement Report

Account: MTED 101/6-39010 Structures
Dispersion: 40.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1979	34.50	$65,331.40	40.00	15.64	0.3910	1.0000	$25,546.27	$1,633.29
1978	35.50	$84,031.98	40.00	15.11	0.3776	1.0000	$31,734.55	$2,100.80
1977	36.50	$22,534.21	40.00	14.58	0.3646	1.0000	$8,216.34	$563.36
1976	37.50	$4,620.93	40.00	14.08	0.3519	1.0000	$1,626.03	$115.52
1975	38.50	$1,745.00	40.00	13.58	0.3395	1.0000	$592.44	$43.63
1974	39.50	$3,994.36	40.00	13.10	0.3274	1.0000	$1,307.89	$99.86
1973	40.50	$12,600.41	40.00	12.63	0.3157	1.0000	$3,978.08	$315.01
1972	41.50	$263,219.15	40.00	12.17	0.3043	1.0000	$80,097.41	$6,580.48
1971	42.50	$888.72	40.00	11.73	0.2932	1.0000	$260.60	$22.22
1970	43.50	$2,379.58	40.00	11.30	0.2825	1.0000	$672.15	$59.49
1969	44.50	$449,637.94	40.00	10.88	0.2720	1.0000	$122,314.35	$11,240.95
1968	45.50	$407,752.30	40.00	10.48	0.2619	1.0000	$106,792.19	$10,193.81
1967	46.50	$341,543.77	40.00	10.08	0.2521	1.0000	$86,095.73	$8,538.59
1966	47.50	$2,737.97	40.00	9.70	0.2426	1.0000	$664.11	$68.45
1965	48.50	$343.73	40.00	9.33	0.2333	1.0000	$80.19	$8.59
1964	49.50	$1,350.10	40.00	8.97	0.2243	1.0000	$302.86	$33.75
1963	50.50	$12,418.26	40.00	8.62	0.2156	1.0000	$2,677.17	$310.46
1962	51.50	$3,385.41	40.00	8.28	0.2071	1.0000	$701.14	$84.64
1961	52.50	$246.48	40.00	7.95	0.1988	1.0000	$49.00	$6.16
1960	53.50	$510.65	40.00	7.63	0.1908	1.0000	$97.42	$12.77
1959	54.50	$687.48	40.00	7.31	0.1829	1.0000	$125.71	$17.19
1958	55.50	$170.00	40.00	7.01	0.1752	1.0000	$29.78	$4.25
1957	56.50	$1,934.89	40.00	6.70	0.1676	1.0000	$324.25	$48.37
1956	57.50	$37,478.30	40.00	6.41	0.1602	1.0000	$6,003.99	$936.96
1955	58.50	$76,603.00	40.00	6.12	0.1529	1.0000	$11,711.14	$1,915.08
1954	59.50	$175.00	40.00	5.83	0.1458	1.0000	$25.51	$4.38
1949	64.50	$19.76	40.00	4.49	0.1122	1.0000	$2.22	$0.49
1948	65.50	$388.31	40.00	4.24	0.1061	1.0000	$41.19	$9.71
1947	66.50	$6,594.83	40.00	4.00	0.1000	1.0000	$659.64	$164.87
1946	67.50	$2,419.92	40.00	3.77	0.0943	1.0000	$228.31	$60.50
1944	69.50	$6,809.62	40.00	3.33	0.0832	1.0000	$566.57	$170.24
1943	70.50	$100.16	40.00	3.10	0.0775	1.0000	$7.76	$2.50
1938	75.50	$44,312.15	40.00	1.69	0.0422	1.0000	$1,868.00	$1,107.80

Generation Arrangement Report

Account: MTED 101/6-39010 Structures
Dispersion: 40.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1936	77.50	$163.90	40.00	1.05	0.0262	1.0000	$4.29	$4.10
1928	85.50	$96,200.28	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	87.50	$206.46	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1923	90.50	$80,033.55	40.00	0.00	0.0000	0.0000	$0.00	$0.00
		$18,513,559.38	40.00	26.29	0.6572	1.0000	$12,166,981.01	$458,427.98

Remaining Life Depreciation Accrual

Account: MTED 101/6-39010 South Bldg Reading
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$50,456,452.54	22.63	$1,121,753.83	2.223212%	4.418496%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($261,183.43)	0.50	($3,002.02)	1.149391%	
Total:	$50,456,452.54 *		$1,118,751.81	2.217262%	4.406671%
Average:	$50,325,860.83		$1,118,751.81	2.223016%	4.429456%
Grand Total:	$50,456,452.54 *		$1,118,751.81	2.217262%	4.406671%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39010 South Bldg Reading
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$50,456,452.54	$25,068,766.07	0.4968	$25,387,686.47	0.5032
Computed	$50,456,452.54	$21,779,236.75	0.4316	$28,677,215.79	0.5684
Difference		$3,289,529.32	0.0652	($3,289,529.32)	-0.0652

Generation Arrangement Report

Account: MTED 101/6-39010 South Bldg Reading
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$1,500,662.83	24.29	23.75	0.9778	1.0000	$1,467,418.93	$61,786.25
2012	1.50	$66,331.61	25.21	23.68	0.9395	1.0000	$62,315.26	$2,631.46
2011	2.50	$603,148.94	26.12	23.62	0.9041	1.0000	$545,287.86	$23,090.66
2010	3.50	$475,095.96	27.03	23.55	0.8713	1.0000	$413,974.70	$17,577.22
2009	4.50	$793,214.52	27.93	23.49	0.8409	1.0000	$667,053.13	$28,398.53
2008	5.50	$550,507.35	28.83	23.43	0.8128	1.0000	$447,426.98	$19,096.16
2007	6.50	$1,020,438.72	29.72	23.37	0.7865	1.0000	$802,536.13	$34,336.38
2006	7.50	$871,795.98	30.60	23.32	0.7619	1.0000	$664,213.99	$28,486.78
2005	8.50	$795,241.17	31.48	23.26	0.7388	1.0000	$587,556.63	$25,260.18
2004	9.50	$2,151,720.43	32.35	23.21	0.7173	1.0000	$1,543,351.39	$66,505.10
2003	10.50	$181,063.55	33.22	23.15	0.6970	1.0000	$126,197.97	$5,450.43
2002	11.50	$27,328.98	34.08	23.10	0.6779	1.0000	$18,525.62	$801.92
2001	12.50	$607,627.25	34.93	23.05	0.6598	1.0000	$400,925.42	$17,394.51
2000	13.50	$549,096.37	35.78	23.00	0.6428	1.0000	$352,963.15	$15,347.23
1999	14.50	$173,979.93	36.62	22.95	0.6267	1.0000	$109,035.04	$4,751.28
1998	15.50	$2,285,684.57	37.45	22.90	0.6115	1.0000	$1,397,593.18	$61,033.11
1997	16.50	$630,488.37	38.28	22.85	0.5970	1.0000	$376,373.30	$16,472.43
1996	17.50	$2,014,003.97	39.09	22.80	0.5832	1.0000	$1,174,619.89	$51,517.26
1995	18.50	$614,197.37	39.91	22.75	0.5702	1.0000	$350,189.61	$15,391.47
1994	19.50	$797,293.70	40.71	22.70	0.5577	1.0000	$444,667.37	$19,585.14
1993	20.50	$4,660,046.57	41.51	22.66	0.5458	1.0000	$2,543,660.25	$112,274.42
1992	21.50	$311,889.99	42.30	22.61	0.5345	1.0000	$166,717.00	$7,374.11
1991	22.50	$13,196,544.72	43.08	22.56	0.5237	1.0000	$6,911,611.43	$306,346.48
1990	23.50	$2,888,260.57	43.85	22.51	0.5134	1.0000	$1,482,904.63	$65,864.42
1989	24.50	$1,347,234.88	44.62	22.47	0.5035	1.0000	$678,376.06	$30,194.58
1988	25.50	$518,320.32	45.38	22.42	0.4941	1.0000	$256,091.02	$11,422.38
1987	26.50	$5,451,561.90	46.13	22.37	0.4850	1.0000	$2,644,126.31	$118,180.71
1986	27.50	$138,282.78	46.87	22.33	0.4763	1.0000	$65,868.61	$2,950.18
1985	28.50	$243,779.90	47.61	22.28	0.4680	1.0000	$114,083.11	$5,120.51
1984	29.50	$172,507.72	48.34	22.23	0.4600	1.0000	$79,349.35	$3,568.90
1983	30.50	$100,670.63	49.06	22.19	0.4523	1.0000	$45,530.75	$2,052.14
1982	31.50	$132,778.97	49.77	22.14	0.4449	1.0000	$59,069.66	$2,667.95
1981	32.50	$10,468.66	50.47	22.09	0.4377	1.0000	$4,582.42	$207.42

Generation Arrangement Report

Account: MTED 101/6-39010 South Bldg Reading
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$101,564.45	51.17	22.05	0.4309	1.0000	$43,760.56	$1,984.93
1979	34.50	$105,880.92	51.86	22.00	0.4243	1.0000	$44,920.12	$2,041.85
1978	35.50	$850,594.01	52.53	21.95	0.4179	1.0000	$355,437.47	$16,191.11
1977	36.50	$34,965.49	53.21	21.90	0.4117	1.0000	$14,395.32	$657.18
1976	37.50	$6,716.02	53.87	21.86	0.4058	1.0000	$2,725.09	$124.67
1975	38.50	$34,312.44	54.52	21.81	0.4000	1.0000	$13,725.58	$629.32
1974	39.50	$32,027.93	55.17	21.76	0.3945	1.0000	$12,633.99	$580.54
1973	40.50	$270,359.79	55.81	21.71	0.3891	1.0000	$105,193.62	$4,844.59
1972	41.50	$99,520.61	56.44	21.67	0.3839	1.0000	$38,205.80	$1,763.43
1971	42.50	$41,920.92	57.06	21.62	0.3789	1.0000	$15,882.62	$734.73
1970	43.50	$23,882.00	57.67	21.57	0.3740	1.0000	$8,931.88	$414.12
1969	44.50	$32,772.04	58.27	21.52	0.3693	1.0000	$12,101.78	$562.39
1968	45.50	$27,319.64	58.87	21.47	0.3647	1.0000	$9,963.39	$464.09
1967	46.50	$1,213,321.82	59.45	21.42	0.3603	1.0000	$437,111.09	$20,407.71
1966	47.50	$577,054.93	60.03	21.37	0.3560	1.0000	$205,402.84	$9,612.45
1965	48.50	$5,502.57	60.60	21.32	0.3518	1.0000	$1,935.60	$90.80
1964	49.50	$16,135.71	61.16	21.27	0.3477	1.0000	$5,610.38	$263.82
1963	50.50	$17,906.07	61.71	21.21	0.3438	1.0000	$6,155.27	$290.15
1962	51.50	$1,118.40	62.26	21.16	0.3399	1.0000	$380.16	$17.96
1961	52.50	$5,397.23	62.79	21.11	0.3362	1.0000	$1,814.39	$85.95
1960	53.50	$1,949.52	63.32	21.06	0.3325	1.0000	$648.29	$30.79
1957	56.50	$2,900.26	64.84	20.89	0.3222	1.0000	$934.43	$44.73
1956	57.50	$2,259.88	65.34	20.84	0.3189	1.0000	$720.72	$34.59
1955	58.50	$2,084.98	65.82	20.78	0.3157	1.0000	$658.27	$31.68
1954	59.50	$1,067,661.95	66.29	20.72	0.3126	1.0000	$333,754.40	$16,105.36
1953	60.50	$51.61	66.76	20.67	0.3096	1.0000	$15.98	$0.77
1943	70.50	$2.17	70.94	20.04	0.2825	1.0000	$0.61	$0.03
		$50,456,452.54	40.01	22.63	0.5684	1.0000	$28,677,215.79	$1,261,147.45

Remaining Life Depreciation Accrual

Account: MTED 101/6-39010 Lebanon Serv Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$5,087,649.98	9.22	$218,576.89	4.296225%	10.843273%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($29,333.59)	0.50	($419.23)	1.429181%	
Total:	$5,087,649.98 *		$218,157.66	4.287985%	10.822475%
Average:	$5,072,983.19		$218,157.66	4.300382%	10.901796%
Grand Total:	$5,087,649.98 *		$218,157.66	4.287985%	10.822475%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39010 Lebanon Serv Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$5,087,649.98	$3,071,866.61	0.6038	$2,015,783.37	0.3962
Computed	$5,087,649.98	$3,049,418.51	0.5994	$2,038,231.47	0.4006
Difference		$22,448.10	0.0044	($22,448.10)	-0.0044

Generation Arrangement Report

Account: MTED 101/6-39010 Lebanon Serv Ctr
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	($216.63)	9.95	9.44	0.9490	1.0000	($205.58)	($21.78)
2012	1.50	$762,751.61	10.93	9.43	0.8625	1.0000	$657,856.65	$69,797.73
2011	2.50	$29,328.85	11.91	9.41	0.7905	1.0000	$23,184.96	$2,462.98
2010	3.50	$68,115.11	12.88	9.40	0.7297	1.0000	$49,705.75	$5,286.60
2009	4.50	$9,769.54	13.86	9.39	0.6777	1.0000	$6,620.48	$704.99
2008	5.50	$283,322.32	14.83	9.38	0.6327	1.0000	$179,249.92	$19,108.17
2007	6.50	$38,888.21	15.79	9.37	0.5934	1.0000	$23,074.72	$2,462.36
2006	7.50	$16,871.12	16.75	9.36	0.5587	1.0000	$9,426.41	$1,006.93
2005	8.50	$490,120.02	17.71	9.35	0.5280	1.0000	$258,766.00	$27,670.61
2004	9.50	$61,987.63	18.67	9.34	0.5005	1.0000	$31,025.84	$3,320.87
2002	11.50	$7,536.60	20.56	9.33	0.4536	1.0000	$3,418.42	$366.58
2001	12.50	$189,800.79	21.50	9.32	0.4333	1.0000	$82,247.08	$8,828.33
2000	13.50	$7,552.50	22.43	9.31	0.4149	1.0000	$3,133.60	$336.66
1999	14.50	$16,870.67	23.36	9.30	0.3980	1.0000	$6,715.35	$722.10
1998	15.50	$5,338.09	24.29	9.29	0.3826	1.0000	$2,042.15	$219.78
1997	16.50	$16,786.42	25.21	9.28	0.3683	1.0000	$6,182.02	$665.94
1996	17.50	$9,986.11	26.12	9.28	0.3551	1.0000	$3,546.02	$382.30
1993	20.50	$164,151.89	28.83	9.25	0.3209	1.0000	$52,680.47	$5,694.15
1992	21.50	$347,810.18	29.72	9.24	0.3110	1.0000	$108,185.96	$11,703.34
1991	22.50	$115,501.93	30.60	9.24	0.3018	1.0000	$34,859.66	$3,774.14
1990	23.50	$3,984.48	31.48	9.23	0.2931	1.0000	$1,168.05	$126.56
1989	24.50	$229,307.03	32.35	9.22	0.2850	1.0000	$65,353.04	$7,087.39
1988	25.50	$49,281.68	33.22	9.21	0.2773	1.0000	$13,668.14	$1,483.49
1987	26.50	$108,719.31	34.08	9.21	0.2701	1.0000	$29,368.87	$3,190.18
1986	27.50	$29,374.80	34.93	9.20	0.2633	1.0000	$7,735.16	$840.91
1985	28.50	$38,293.80	35.78	9.19	0.2569	1.0000	$9,836.94	$1,070.31
1984	29.50	$187,028.19	36.62	9.18	0.2508	1.0000	$46,905.54	$5,107.62
1983	30.50	$14,849.24	37.45	9.18	0.2450	1.0000	$3,638.35	$396.51
1982	31.50	$13,933.41	38.28	9.17	0.2395	1.0000	$3,337.64	$364.03
1981	32.50	$2,563.54	39.09	9.16	0.2343	1.0000	$600.71	$65.57
1979	34.50	$9,949.28	40.71	9.15	0.2247	1.0000	$2,235.25	$244.40
1978	35.50	$1,272.00	41.51	9.14	0.2202	1.0000	$280.06	$30.65
1977	36.50	$5,997.30	42.30	9.13	0.2159	1.0000	$1,294.68	$141.80

Generation Arrangement Report

Account: MTED 101/6-39010 Lebanon Serv Ctr
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1976	37.50	$1,970.88	43.08	9.12	0.2118	1.0000	$417.40	$45.75
1975	38.50	$2,929.78	43.85	9.12	0.2079	1.0000	$609.02	$66.81
1974	39.50	$29,931.53	44.62	9.11	0.2041	1.0000	$6,109.90	$670.83
1973	40.50	$22,095.79	45.38	9.10	0.2005	1.0000	$4,431.07	$486.93
1972	41.50	$623.97	46.13	9.09	0.1971	1.0000	$122.99	$13.53
1971	42.50	$1,823.72	46.87	9.08	0.1938	1.0000	$353.47	$38.91
1970	43.50	$2,960.38	47.61	9.08	0.1907	1.0000	$564.42	$62.18
1969	44.50	$9,343.58	48.34	9.07	0.1876	1.0000	$1,753.03	$193.30
1968	45.50	$17,184.22	49.06	9.06	0.1847	1.0000	$3,174.00	$350.30
1967	46.50	$6,586.71	49.77	9.05	0.1819	1.0000	$1,198.14	$132.35
1966	47.50	$2,016.11	50.47	9.04	0.1792	1.0000	$361.30	$39.95
1965	48.50	$1,653,356.29	51.17	9.04	0.1766	1.0000	$291,998.42	$32,312.47
		$5,087,649.98	23.23	9.22	0.4006	1.0000	$2,038,231.47	$219,055.48

Remaining Life Depreciation Accrual

Account: MTED 101/6-39010 Easton Serv Center
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$4,604,359.68	4.44	$151,511.58	3.290611%	22.545327%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($29,047.67)	0.50	($480.80)	1.655210%	
Total:	$4,604,359.68 *		$151,030.78	3.280169%	22.473782%
Average:	$4,589,835.85		$151,030.78	3.290549%	22.970211%
Grand Total:	$4,604,359.68 *		$151,030.78	3.280169%	22.473782%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39010 Easton Serv Center
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$4,604,359.68	$3,932,328.69	0.8540	$672,030.99	0.1460
Computed	$4,604,359.68	$3,684,385.29	0.8002	$919,974.39	0.1998
Difference		$247,943.40	0.0538	($247,943.40)	-0.0538

Generation Arrangement Report

Account: MTED 101/6-39010 Easton Serv Center
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2012	1.50	$58,679.98	5.99	4.49	0.7495	1.0000	$43,982.08	$9,800.42
2011	2.50	$244,425.93	6.98	4.48	0.6425	1.0000	$157,045.15	$35,016.13
2010	3.50	$24,747.33	7.97	4.48	0.5623	1.0000	$13,915.75	$3,104.63
2008	5.50	$15,370.01	9.95	4.48	0.4502	1.0000	$6,919.27	$1,545.48
2007	6.50	$65,349.08	10.93	4.47	0.4095	1.0000	$26,759.21	$5,979.95
2005	8.50	$116,963.58	12.88	4.47	0.3469	1.0000	$40,579.94	$9,077.86
2004	9.50	$15,289.62	13.86	4.47	0.3224	1.0000	$4,929.86	$1,103.33
2003	10.50	$88,710.82	14.83	4.47	0.3012	1.0000	$26,720.83	$5,982.94
2002	11.50	$45,902.84	15.79	4.46	0.2827	1.0000	$12,975.16	$2,906.51
2001	12.50	$66,481.90	16.75	4.46	0.2663	1.0000	$17,704.80	$3,967.90
2000	13.50	$242,343.72	17.71	4.46	0.2518	1.0000	$61,023.23	$13,681.95
1999	14.50	$17,372.32	18.67	4.46	0.2388	1.0000	$4,149.27	$930.69
1998	15.50	$63,557.88	19.62	4.46	0.2272	1.0000	$14,439.91	$3,240.26
1997	16.50	$465.59	20.56	4.45	0.2167	1.0000	$100.87	$22.65
1996	17.50	$106,358.92	21.50	4.45	0.2071	1.0000	$22,027.88	$4,947.14
1995	18.50	$18,941.46	22.43	4.45	0.1984	1.0000	$3,757.97	$844.33
1994	19.50	$315,893.59	23.36	4.45	0.1904	1.0000	$60,155.40	$13,520.83
1993	20.50	$10,060.09	24.29	4.45	0.1831	1.0000	$1,842.02	$414.20
1992	21.50	$326,871.94	25.21	4.45	0.1764	1.0000	$57,645.88	$12,967.43
1991	22.50	$79,320.97	26.12	4.44	0.1701	1.0000	$13,494.25	$3,036.69
1990	23.50	$49,781.71	27.03	4.44	0.1643	1.0000	$8,181.28	$1,841.78
1989	24.50	$762,550.19	27.93	4.44	0.1590	1.0000	$121,220.22	$27,300.69
1988	25.50	$128,878.50	28.83	4.44	0.1540	1.0000	$19,842.54	$4,470.57
1987	26.50	$228,795.84	29.72	4.44	0.1493	1.0000	$34,157.44	$7,698.67
1986	27.50	$33,373.66	30.60	4.44	0.1449	1.0000	$4,836.54	$1,090.52
1985	28.50	$25,680.47	31.48	4.43	0.1408	1.0000	$3,616.28	$815.72
1984	29.50	$67,557.25	32.35	4.43	0.1370	1.0000	$9,253.50	$2,088.05
1983	30.50	$45,187.07	33.22	4.43	0.1334	1.0000	$6,025.76	$1,360.24
1982	31.50	$8,182.31	34.08	4.43	0.1299	1.0000	$1,063.21	$240.10
1981	32.50	$7,060.29	34.93	4.43	0.1267	1.0000	$894.65	$202.11
1979	34.50	$5,272.82	36.62	4.42	0.1208	1.0000	$636.92	$144.00
1978	35.50	$673.65	37.45	4.42	0.1181	1.0000	$79.53	$17.99
1977	36.50	$689.03	38.28	4.42	0.1155	1.0000	$79.56	$18.00

Generation Arrangement Report

Account: MTED 101/6-39010 Easton Serv Center
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1976	37.50	$9,710.27	39.09	4.42	0.1130	1.0000	$1,097.34	$248.38
1974	39.50	$28,072.24	40.71	4.41	0.1084	1.0000	$3,044.16	$689.58
1973	40.50	$4,879.76	41.51	4.41	0.1063	1.0000	$518.79	$117.57
1972	41.50	$11,216.29	42.30	4.41	0.1043	1.0000	$1,169.74	$265.19
1971	42.50	$4,846.49	43.08	4.41	0.1024	1.0000	$496.07	$112.51
1970	43.50	$71,304.58	43.85	4.41	0.1005	1.0000	$7,166.72	$1,626.04
1969	44.50	$2,350.70	44.62	4.41	0.0987	1.0000	$232.11	$52.68
1968	45.50	$434.20	45.38	4.40	0.0970	1.0000	$42.14	$9.57
1967	46.50	$690.18	46.13	4.40	0.0954	1.0000	$65.86	$14.96
1966	47.50	$2,298.62	46.87	4.40	0.0939	1.0000	$215.78	$49.04
1965	48.50	$1,126.00	47.61	4.40	0.0924	1.0000	$104.03	$23.65
1964	49.50	$158.34	48.34	4.40	0.0910	1.0000	$14.40	$3.28
1963	50.50	$1,180,035.91	49.06	4.39	0.0896	1.0000	$105,711.75	$24,054.73
1962	51.50	$445.74	49.77	4.39	0.0883	1.0000	$39.34	$8.96
		$4,604,359.68	22.28	4.44	0.1998	1.0000	$919,974.39	$206,655.87

Remaining Life Depreciation Accrual

Account: MTED 101/6-39010 York Serv Center
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - S0
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2013

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2013 Additions	$7,014,293.10	15.70	$196,425.33	2.800358%	6.370602%
2013 Additions	$0.00	0.00	$0.00	0.000000%	
2013 Retirements	($36,442.05)	0.50	($504.41)	1.384143%	
Total:	$7,014,293.10 *		$195,920.92	2.793167%	6.354243%
Average:	$6,996,072.07		$195,920.92	2.800442%	6.392017%
Grand Total:	$7,014,293.10 *		$195,920.92	2.793167%	6.354243%

* Excluding 2013 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39010 York Serv Center
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - S0
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2013

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$7,014,293.10	$3,930,984.39	0.5604	$3,083,308.71	0.4396
Computed	$7,014,293.10	$3,666,384.00	0.5227	$3,347,909.10	0.4773
Difference		$264,600.39	0.0377	($264,600.39)	-0.0377

Generation Arrangement Report

Account: MTED 101/6-39010 York Serv Center
Dispersion: 80.00 - S0

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2013

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.00	$2,339.09	15.79	15.78	0.9989	1.0000	$2,336.47	$148.11
2011	1.50	$193,390.36	17.71	16.20	0.9147	1.0000	$176,888.16	$10,918.20
2008	4.50	$55,781.09	20.56	16.11	0.7834	1.0000	$43,699.84	$2,713.16
2007	5.50	$32,515.63	21.50	16.08	0.7479	1.0000	$24,316.86	$1,512.42
2005	7.50	$70,277.83	23.36	16.02	0.6858	1.0000	$48,198.06	$3,008.02
2004	8.50	$134,879.46	24.29	16.00	0.6586	1.0000	$88,829.94	$5,553.34
2003	9.50	$20,574.70	25.21	15.97	0.6336	1.0000	$13,035.13	$816.22
2002	10.50	$213,616.46	26.12	15.94	0.6104	1.0000	$130,396.43	$8,177.99
2001	11.50	$98,077.08	27.03	15.92	0.5890	1.0000	$57,766.31	$3,628.58
2000	12.50	$23,440.74	27.93	15.89	0.5691	1.0000	$13,338.99	$839.22
1998	14.50	$79,156.93	29.72	15.85	0.5332	1.0000	$42,208.17	$2,663.52
1997	15.50	$4,454.10	30.60	15.82	0.5170	1.0000	$2,302.93	$145.54
1996	16.50	$50,571.95	31.48	15.80	0.5018	1.0000	$25,379.19	$1,606.38
1995	17.50	$760,405.22	32.35	15.78	0.4876	1.0000	$370,782.56	$23,502.51
1994	18.50	$3,521,484.99	33.22	15.75	0.4742	1.0000	$1,669,935.72	$106,004.83
1993	19.50	$14,674.50	34.08	15.73	0.4616	1.0000	$6,773.63	$430.60
1992	20.50	$60,441.23	34.93	15.71	0.4497	1.0000	$27,178.01	$1,730.25
1991	21.50	$325,458.05	35.78	15.69	0.4384	1.0000	$142,681.48	$9,096.55
1990	22.50	$9,966.86	36.62	15.66	0.4277	1.0000	$4,263.31	$272.19
1989	23.50	$108,115.95	37.45	15.64	0.4177	1.0000	$45,154.67	$2,886.95
1988	24.50	$57,368.67	38.28	15.62	0.4081	1.0000	$23,409.36	$1,498.84
1987	25.50	$471,523.88	39.09	15.60	0.3989	1.0000	$188,112.51	$12,061.35
1986	26.50	$86,083.67	39.91	15.57	0.3903	1.0000	$33,597.33	$2,157.21
1985	27.50	$11,473.05	40.71	15.55	0.3820	1.0000	$4,383.16	$281.83
1984	28.50	$55,638.29	41.51	15.53	0.3742	1.0000	$20,817.85	$1,340.49
1983	29.50	$1,409.79	42.30	15.51	0.3667	1.0000	$516.93	$33.33
1981	31.50	$4,535.71	43.85	15.46	0.3527	1.0000	$1,599.57	$103.43
1980	32.50	$4,404.32	44.62	15.44	0.3461	1.0000	$1,524.31	$98.71
1979	33.50	$1,237.44	45.38	15.42	0.3398	1.0000	$420.51	$27.27
1978	34.50	$4,709.73	46.13	15.40	0.3338	1.0000	$1,572.17	$102.10
1977	35.50	$3,383.43	46.87	15.38	0.3280	1.0000	$1,109.92	$72.18
1976	36.50	$413.40	47.61	15.35	0.3225	1.0000	$133.32	$8.68
1974	38.50	$1,461.62	49.06	15.31	0.3121	1.0000	$456.14	$29.79

Generation Arrangement Report

Account: MTED 101/6-39010 York Serv Center
Dispersion: 80.00 - S0
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2013

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1973	39.50	$93,768.46	49.77	15.29	0.3072	1.0000	$28,802.42	$1,884.10
1972	40.50	$8,124.72	50.47	15.26	0.3024	1.0000	$2,457.13	$160.97
1971	41.50	$1,202.29	51.17	15.24	0.2979	1.0000	$358.13	$23.50
1970	42.50	$872.92	51.86	15.22	0.2935	1.0000	$256.19	$16.83
1969	43.50	$11,353.36	52.53	15.20	0.2893	1.0000	$3,284.02	$216.11
1968	44.50	$22,686.60	53.21	15.17	0.2852	1.0000	$6,469.44	$426.39
1967	45.50	$2,135.80	53.87	15.15	0.2812	1.0000	$600.64	$39.65
1966	46.50	$8,543.41	54.52	15.13	0.2774	1.0000	$2,370.13	$156.69
1965	47.50	$3,064.50	55.17	15.10	0.2737	1.0000	$838.89	$55.55
1964	48.50	$5,174.32	55.81	15.08	0.2702	1.0000	$1,398.03	$92.72
1963	49.50	$74,905.60	56.44	15.05	0.2667	1.0000	$19,980.84	$1,327.27
1962	50.50	$648.25	57.06	15.03	0.2634	1.0000	$170.76	$11.36
1961	51.50	$1,469.62	57.67	15.01	0.2602	1.0000	$382.39	$25.48
1960	52.50	$1,745.87	58.27	14.98	0.2571	1.0000	$448.82	$29.96
1959	53.50	$2,679.76	58.87	14.96	0.2541	1.0000	$680.80	$45.52
1957	55.50	$1,055.44	60.03	14.90	0.2483	1.0000	$262.04	$17.58
1956	56.50	$2,617.82	60.60	14.88	0.2455	1.0000	$642.71	$43.20
1955	57.50	$1,117.10	61.16	14.85	0.2428	1.0000	$271.28	$18.26
1954	58.50	$4,127.44	61.71	14.83	0.2402	1.0000	$991.56	$66.88
1953	59.50	$224,197.91	62.26	14.80	0.2377	1.0000	$53,293.56	$3,601.13
1951	61.50	$7,409.36	63.32	14.74	0.2329	1.0000	$1,725.33	$117.02
1949	63.50	$551.40	64.34	14.69	0.2283	1.0000	$125.87	$8.57
1947	65.50	$180.14	65.34	14.63	0.2239	1.0000	$40.34	$2.76
1945	67.50	$425.55	66.29	14.57	0.2198	1.0000	$93.53	$6.42
1944	68.50	$655.00	66.76	14.54	0.2178	1.0000	$142.66	$9.81
1943	69.50	$412.69	67.21	14.51	0.2159	1.0000	$89.09	$6.14
1941	71.50	$34.09	68.10	14.45	0.2121	1.0000	$7.23	$0.50
1939	73.50	$298.62	68.95	14.38	0.2085	1.0000	$62.27	$4.33
1937	75.50	$350.40	69.77	14.31	0.2051	1.0000	$71.87	$5.02
1936	76.50	$146.25	70.17	14.28	0.2035	1.0000	$29.76	$2.08
1930	82.50	$407.42	72.37	14.05	0.1942	1.0000	$79.11	$5.63
1929	83.50	$14.70	72.71	14.01	0.1927	1.0000	$2.83	$0.20
1928	84.50	$258.31	73.03	13.97	0.1913	1.0000	$49.41	$3.54

Generation Arrangement Report

Account: MTED 101/6-39010 York Serv Center
Dispersion: 80.00 - S0

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2013

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1927	85.50	$2,176.86	73.36	13.93	0.1899	1.0000	$413.33	$29.68
1926	86.50	$106.10	73.67	13.89	0.1885	1.0000	$20.00	$1.44
1925	87.50	$3,428.79	73.97	13.84	0.1871	1.0000	$641.60	$46.35
1923	89.50	$60.00	74.56	13.75	0.1844	1.0000	$11.07	$0.80
1922	90.50	$4,167.27	74.84	13.70	0.1831	1.0000	$763.08	$55.69
1921	91.50	$12,070.93	75.11	13.66	0.1818	1.0000	$2,194.58	$160.71
1919	93.50	$1,464.44	75.63	13.56	0.1792	1.0000	$262.48	$19.36
1917	95.50	$468.91	76.12	13.45	0.1767	1.0000	$82.85	$6.16
1908	104.50	$440.97	77.95	12.90	0.1654	1.0000	$72.96	$5.66
1904	108.50	$24,008.49	78.58	12.60	0.1603	1.0000	$3,849.13	$305.53
		$7,014,293.10	33.00	15.70	0.4773	1.0000	$3,347,909.10	$212,532.39

Remaining Life Depreciation Accrual

Account: MTED 101/6-39020 Land/Yard Improvem
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25.00 - R1
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$4,340,628.36	9.61	$160,947.16	3.707923%	10.408190%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($398,707.81)	0.50	($7,974.16)	2.000001%	
Total:	$4,340,628.36 *		$152,973.00	3.524213%	9.892515%
Average:	$4,141,274.46		$152,973.00	3.693863%	11.356595%
Grand Total:	$4,340,628.36 *		$152,973.00	3.524213%	9.892515%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39020 Land/Yard Improvem
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25 - R1
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$4,340,628.36	$2,794,277.38	0.6437	$1,546,350.98	0.3563
Computed	$4,340,628.36	$2,672,469.75	0.6157	$1,668,158.61	0.3843
Difference		$121,807.63	0.0281	($121,807.63)	-0.0281

Generation Arrangement Report

Account: MTED 101/6-39020 Land/Yard Improvem
Dispersion: 25.00 - R1
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2012	1.50	$14,667.85	25.00	23.89	0.9558	1.0000	$14,019.50	$586.71
2011	2.50	$47,855.63	25.00	23.17	0.9268	1.0000	$44,351.95	$1,914.23
2010	3.50	$25,215.29	25.00	22.45	0.8981	1.0000	$22,645.99	$1,008.61
2009	4.50	$47,611.60	25.00	21.74	0.8697	1.0000	$41,410.13	$1,904.46
2008	5.50	$62,388.86	25.00	21.04	0.8417	1.0000	$52,511.67	$2,495.55
2003	10.50	$16,391.93	25.00	17.63	0.7053	1.0000	$11,560.54	$655.68
2001	12.50	$151,639.43	25.00	16.32	0.6527	1.0000	$98,974.90	$6,065.58
2000	13.50	$26,628.75	25.00	15.67	0.6270	1.0000	$16,695.77	$1,065.15
1998	15.50	$42,666.06	25.00	14.42	0.5769	1.0000	$24,612.24	$1,706.64
1996	17.50	$1,656.84	25.00	13.22	0.5287	1.0000	$875.94	$66.27
1994	19.50	$74,069.34	25.00	12.07	0.4826	1.0000	$35,746.59	$2,962.77
1993	20.50	$365,795.34	25.00	11.51	0.4604	1.0000	$168,414.31	$14,631.81
1992	21.50	$199,927.52	25.00	10.97	0.4388	1.0000	$87,719.27	$7,997.10
1991	22.50	$462,771.52	25.00	10.44	0.4177	1.0000	$193,287.90	$18,510.86
1990	23.50	$1,395,442.52	25.00	9.93	0.3971	1.0000	$554,194.95	$55,817.70
1989	24.50	$68,392.37	25.00	9.43	0.3772	1.0000	$25,795.51	$2,735.69
1988	25.50	$375,581.29	25.00	8.94	0.3577	1.0000	$134,362.46	$15,023.25
1987	26.50	$101,127.93	25.00	8.47	0.3389	1.0000	$34,267.32	$4,045.12
1986	27.50	$71,688.99	25.00	8.01	0.3205	1.0000	$22,975.41	$2,867.56
1985	28.50	$80,395.42	25.00	7.57	0.3026	1.0000	$24,330.62	$3,215.82
1984	29.50	$1,972.61	25.00	7.13	0.2853	1.0000	$562.77	$78.90
1982	31.50	$2,164.98	25.00	6.30	0.2520	1.0000	$545.67	$86.60
1981	32.50	$32,465.96	25.00	5.90	0.2361	1.0000	$7,665.92	$1,298.64
1980	33.50	$2,987.21	25.00	5.52	0.2206	1.0000	$659.11	$119.49
1979	34.50	$9,305.15	25.00	5.14	0.2056	1.0000	$1,913.23	$372.21
1978	35.50	$5,678.28	25.00	4.77	0.1910	1.0000	$1,084.50	$227.13
1975	38.50	$10,843.46	25.00	3.74	0.1496	1.0000	$1,621.85	$433.74
1974	39.50	$12,176.79	25.00	3.41	0.1365	1.0000	$1,662.61	$487.07
1973	40.50	$13,701.90	25.00	3.10	0.1239	1.0000	$1,697.41	$548.08
1972	41.50	$59,873.55	25.00	2.79	0.1116	1.0000	$6,680.11	$2,394.94
1971	42.50	$46,349.09	25.00	2.49	0.0996	1.0000	$4,615.21	$1,853.96
1970	43.50	$800.00	25.00	2.20	0.0878	1.0000	$70.26	$32.00
1969	44.50	$174,664.04	25.00	1.90	0.0762	1.0000	$13,307.48	$6,986.56

Generation Arrangement Report

Account: MTED 101/6-39020 Land/Yard Improvem
Dispersion: 25.00 - R1

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1968	45.50	$127,434.39	25.00	1.61	0.0644	1.0000	$8,206.10	$5,097.38
1967	46.50	$174,332.32	25.00	1.30	0.0520	1.0000	$9,067.55	$6,973.29
1964	49.50	$3,068.56	25.00	0.37	0.0149	1.0000	$45.84	$122.74
1963	50.50	$2,307.50	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	51.50	$3,855.39	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1961	52.50	$471.55	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1956	57.50	$5,774.43	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1955	58.50	$16,621.32	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1947	66.50	$1,865.40	25.00	0.00	0.0000	0.0000	$0.00	$0.00
		$4,340,628.36	25.00	9.61	0.3843	1.0000	$1,668,158.61	$172,389.31

Remaining Life Depreciation Accrual

Account: MTED 101/6-39020 Corp Hqtrs Reading
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - SQ
/age Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$3,890,763.60	24.26	$90,646.59	2.329789%	4.121746%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$3,890,763.60 *		$90,646.59	2.329789%	4.121746%
Average:	$3,890,763.60		$90,646.59	2.329789%	4.121746%
Grand Total:	$3,890,763.60 *		$90,646.59	2.329789%	4.121746%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39020 Corp Hqtrs Reading
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$3,890,763.60	$1,691,535.60	0.4348	$2,199,228.00	0.5652
Computed	$3,890,763.60	$1,982,900.28	0.5096	$1,907,863.32	0.4904
Difference		($291,364.68)	-0.0749	$291,364.68	0.0749

Generation Arrangement Report

Account: MTED 101/6-39020 Corp Hqtrs Reading
Dispersion: 80.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2008	5.50	$1,606.11	30.00	24.50	0.8167	1.0000	$1,311.66	$53.54
2003	10.50	$189,493.31	35.00	24.50	0.7000	1.0000	$132,645.32	$5,414.09
2001	12.50	$3,420.00	37.00	24.50	0.6622	1.0000	$2,264.59	$92.43
2000	13.50	$75,842.85	38.00	24.50	0.6447	1.0000	$48,898.68	$1,995.86
1997	16.50	$95,210.73	41.00	24.50	0.5976	1.0000	$56,894.22	$2,322.21
1996	17.50	$83,603.00	42.00	24.50	0.5833	1.0000	$48,768.42	$1,990.55
1995	18.50	$2,338.50	43.00	24.50	0.5698	1.0000	$1,332.40	$54.38
1994	19.50	$175,536.31	44.00	24.50	0.5568	1.0000	$97,741.81	$3,989.46
1993	20.50	$444,601.76	45.00	24.50	0.5444	1.0000	$242,060.96	$9,880.04
1992	21.50	$81,073.88	46.00	24.50	0.5326	1.0000	$43,180.65	$1,762.48
1991	22.50	$816,371.40	47.00	24.50	0.5213	1.0000	$425,555.30	$17,369.60
1990	23.50	$165,312.05	48.00	24.50	0.5104	1.0000	$84,378.03	$3,444.00
1989	24.50	$137,470.15	49.00	24.50	0.5000	1.0000	$68,735.08	$2,805.51
1988	25.50	$87,797.03	50.00	24.50	0.4900	1.0000	$43,020.54	$1,755.94
1987	26.50	$605,045.66	51.00	24.50	0.4804	1.0000	$290,659.19	$11,863.64
1986	27.50	$14,389.11	52.00	24.50	0.4712	1.0000	$6,779.48	$276.71
1985	28.50	$3,055.75	53.00	24.50	0.4623	1.0000	$1,412.56	$57.66
1984	29.50	$61,879.76	54.00	24.50	0.4537	1.0000	$28,075.08	$1,145.92
1983	30.50	$14,183.37	55.00	24.50	0.4455	1.0000	$6,318.05	$257.88
1982	31.50	$3,163.38	56.00	24.50	0.4375	1.0000	$1,383.98	$56.49
1981	32.50	$504.83	57.00	24.50	0.4298	1.0000	$216.99	$8.86
1979	34.50	$3,304.44	59.00	24.50	0.4153	1.0000	$1,372.18	$56.01
1978	35.50	$106,989.74	60.00	24.50	0.4083	1.0000	$43,687.48	$1,783.16
1976	37.50	$1,780.36	62.00	24.50	0.3952	1.0000	$703.53	$28.72
1975	38.50	$741.64	63.00	24.50	0.3889	1.0000	$288.42	$11.77
1974	39.50	$9,068.02	64.00	24.50	0.3828	1.0000	$3,471.35	$141.69
1973	40.50	$72,471.28	65.00	24.50	0.3769	1.0000	$27,316.10	$1,114.94
1972	41.50	$26,800.39	66.00	24.50	0.3712	1.0000	$9,948.63	$406.07
1971	42.50	$8,843.60	67.00	24.50	0.3657	1.0000	$3,233.85	$131.99
1970	43.50	$102,537.30	68.00	24.50	0.3603	1.0000	$36,943.59	$1,507.90
1969	44.50	$8,029.39	69.00	24.50	0.3551	1.0000	$2,851.02	$116.37
1968	45.50	$14,177.80	70.00	24.50	0.3500	1.0000	$4,962.23	$202.54
1967	46.50	$49,235.02	71.00	24.50	0.3451	1.0000	$16,989.55	$693.45

Generation Arrangement Report

Account: MTED 101/6-39020 Corp Hqtrs Reading
Dispersion: 80.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1966	47.50	$104,494.80	72.00	24.50	0.3403	1.0000	$35,557.26	$1,451.32
1965	48.50	$50,958.90	73.00	24.50	0.3356	1.0000	$17,102.64	$698.07
1964	49.50	$33,910.73	74.00	24.50	0.3311	1.0000	$11,227.20	$458.25
1963	50.50	$1,768.71	75.00	24.50	0.3267	1.0000	$577.78	$23.58
1962	51.50	$297.38	76.00	24.50	0.3224	1.0000	$95.87	$3.91
1959	54.50	$595.20	79.00	24.50	0.3101	1.0000	$184.59	$7.53
1955	58.50	$3,737.79	80.00	21.50	0.2688	1.0000	$1,004.53	$46.72
1954	59.50	$229,122.17	80.00	20.50	0.2563	1.0000	$58,712.56	$2,864.03
		$3,890,763.60	49.66	24.26	0.4904	1.0000	$1,907,863.32	$78,345.29

Remaining Life Depreciation Accrual

Account: MTED 101/6-39020 Lebanon Ser Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$1,009,738.85	9.50	$23,374.12	2.314868%	10.526316%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$1,009,738.85 *		$23,374.12	2.314868%	10.526316%
Average:	$1,009,738.85		$23,374.12	2.314868%	10.526316%
Grand Total:	$1,009,738.85 *		$23,374.12	2.314868%	10.526316%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39020 Lebanon Ser Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$1,009,738.85	$787,684.70	0.7801	$222,054.15	0.2199
Computed	$1,009,738.85	$760,228.37	0.7529	$249,510.48	0.2471
Difference		$27,456.33	0.0272	($27,456.33)	-0.0272

Generation Arrangement Report

Account: MTED 101/6-39020 Lebanon Ser Ctr
Dispersion: 80.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2009	4.50	$44,544.81	14.00	9.50	0.6786	1.0000	$30,226.84	$3,181.77
2001	12.50	$47,346.47	22.00	9.50	0.4318	1.0000	$20,445.07	$2,152.11
1992	21.50	$2,819.99	31.00	9.50	0.3065	1.0000	$864.19	$90.97
1990	23.50	$145,997.58	33.00	9.50	0.2879	1.0000	$42,029.61	$4,424.17
1989	24.50	$36,451.45	34.00	9.50	0.2794	1.0000	$10,184.96	$1,072.10
1988	25.50	$91,277.33	35.00	9.50	0.2714	1.0000	$24,775.28	$2,607.92
1987	26.50	$82,111.56	36.00	9.50	0.2639	1.0000	$21,668.33	$2,280.88
1986	27.50	$40,883.30	37.00	9.50	0.2568	1.0000	$10,497.06	$1,104.95
1985	28.50	$16,092.86	38.00	9.50	0.2500	1.0000	$4,023.22	$423.50
1984	29.50	$5,751.81	39.00	9.50	0.2436	1.0000	$1,401.08	$147.48
1983	30.50	$508.21	40.00	9.50	0.2375	1.0000	$120.70	$12.71
1978	35.50	$4,435.54	45.00	9.50	0.2111	1.0000	$936.39	$98.57
1977	36.50	$838.77	46.00	9.50	0.2065	1.0000	$173.22	$18.23
1973	40.50	$64,865.72	50.00	9.50	0.1900	1.0000	$12,324.49	$1,297.31
1971	42.50	$326.10	52.00	9.50	0.1827	1.0000	$59.58	$6.27
1970	43.50	$2,356.46	53.00	9.50	0.1792	1.0000	$422.38	$44.46
1969	44.50	$489.36	54.00	9.50	0.1759	1.0000	$86.09	$9.06
1968	45.50	$3,639.67	55.00	9.50	0.1727	1.0000	$628.67	$66.18
1967	46.50	$2,095.20	56.00	9.50	0.1696	1.0000	$355.44	$37.41
1966	47.50	$505.60	57.00	9.50	0.1667	1.0000	$84.27	$8.87
1965	48.50	$416,401.06	58.00	9.50	0.1638	1.0000	$68,203.62	$7,179.33
		$1,009,738.85	38.45	9.50	0.2471	1.0000	$249,510.48	$26,264.26

Remaining Life Depreciation Accrual

Account: MTED 101/6-39020 Easton Ser Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$1,369,572.59	4.50	$116,781.75	8.526876%	22.222222%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$1,369,572.59 *		$116,781.75	8.526876%	22.222222%
Average:	$1,369,572.59		$116,781.75	8.526876%	22.222222%
Grand Total:	$1,369,572.59 *		$116,781.75	8.526876%	22.222222%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39020 Easton Ser Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$1,369,572.59	$844,054.71	0.6163	$525,517.88	0.3837
Computed	$1,369,572.59	$1,018,634.05	0.7438	$350,938.54	0.2562
Difference		($174,579.34)	-0.1275	$174,579.34	0.1275

Generation Arrangement Report

Account: MTED 101/6-39020 Easton Ser Ctr
Dispersion: 80.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2009	4.50	$53,333.60	9.00	4.50	0.5000	1.0000	$26,666.80	$5,925.96
2008	5.50	$109,364.26	10.00	4.50	0.4500	1.0000	$49,213.92	$10,936.43
2007	6.50	$289,844.21	11.00	4.50	0.4091	1.0000	$118,572.63	$26,349.47
2004	9.50	$74,575.15	14.00	4.50	0.3214	1.0000	$23,970.58	$5,326.80
2002	11.50	$46,481.00	16.00	4.50	0.2813	1.0000	$13,072.78	$2,905.06
2000	13.50	$137,643.36	18.00	4.50	0.2500	1.0000	$34,410.84	$7,646.85
1994	19.50	$66,001.38	24.00	4.50	0.1875	1.0000	$12,375.26	$2,750.06
1993	20.50	$47,433.52	25.00	4.50	0.1800	1.0000	$8,538.03	$1,897.34
1991	22.50	$2,873.08	27.00	4.50	0.1667	1.0000	$478.85	$106.41
1988	25.50	$124,462.36	30.00	4.50	0.1500	1.0000	$18,669.35	$4,148.75
1987	26.50	$132,179.26	31.00	4.50	0.1452	1.0000	$19,187.31	$4,263.85
1985	28.50	$4,475.54	33.00	4.50	0.1364	1.0000	$610.30	$135.62
1984	29.50	$32.96	34.00	4.50	0.1324	1.0000	$4.36	$0.97
1983	30.50	$4,900.00	35.00	4.50	0.1286	1.0000	$630.00	$140.00
1978	35.50	$40,031.02	40.00	4.50	0.1125	1.0000	$4,503.49	$1,000.78
1974	39.50	$2,190.96	44.00	4.50	0.1023	1.0000	$224.08	$49.79
1973	40.50	$14,353.93	45.00	4.50	0.1000	1.0000	$1,435.39	$318.98
1969	44.50	$15,274.32	49.00	4.50	0.0918	1.0000	$1,402.74	$311.72
1968	45.50	$31,040.73	50.00	4.50	0.0900	1.0000	$2,793.67	$620.81
1965	48.50	$3,748.35	53.00	4.50	0.0849	1.0000	$318.26	$70.72
1964	49.50	$3,515.68	54.00	4.50	0.0833	1.0000	$292.97	$65.11
1963	50.50	$165,817.92	55.00	4.50	0.0818	1.0000	$13,566.92	$3,014.87
		$1,369,572.59	17.56	4.50	0.2562	1.0000	$350,938.54	$77,986.34

Remaining Life Depreciation Accrual

Account: MTED 101/6-39020 York Ser Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$1,855,578.29	15.42	$46,965.10	2.531022%	6.484446%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$1,855,578.29 *		$46,965.10	2.531022%	6.484446%
Average:	$1,855,578.29		$46,965.10	2.531022%	6.484446%
Grand Total:	$1,855,578.29 *		$46,965.10	2.531022%	6.484446%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39020 York Ser Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$1,855,578.29	$1,131,305.23	0.6097	$724,273.06	0.3903
Computed	$1,855,578.29	$1,082,400.73	0.5833	$773,177.56	0.4167
Difference		$48,904.50	0.0264	($48,904.50)	-0.0264

Generation Arrangement Report

Account: MTED 101/6-39020 York Ser Ctr
Dispersion: 80.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2009	4.50	$67,927.29	20.00	15.50	0.7750	1.0000	$52,643.65	$3,396.36
2008	5.50	$18,006.26	21.00	15.50	0.7381	1.0000	$13,290.33	$857.44
2004	9.50	$89,821.37	25.00	15.50	0.6200	1.0000	$55,689.25	$3,592.85
2003	10.50	$33,602.62	26.00	15.50	0.5962	1.0000	$20,032.33	$1,292.41
1997	16.50	$5,862.69	32.00	15.50	0.4844	1.0000	$2,839.74	$183.21
1995	18.50	$21,413.97	34.00	15.50	0.4559	1.0000	$9,762.25	$629.82
1994	19.50	$463,090.82	35.00	15.50	0.4429	1.0000	$205,083.08	$13,231.17
1993	20.50	$221,902.70	36.00	15.50	0.4306	1.0000	$95,541.44	$6,163.96
1992	21.50	$34,890.32	37.00	15.50	0.4189	1.0000	$14,616.22	$942.98
1991	22.50	$125,774.10	38.00	15.50	0.4079	1.0000	$51,302.59	$3,309.84
1990	23.50	$231,736.66	39.00	15.50	0.3974	1.0000	$92,100.47	$5,941.97
1988	25.50	$27,818.66	41.00	15.50	0.3780	1.0000	$10,516.81	$678.50
'987	26.50	$176,896.53	42.00	15.50	0.3690	1.0000	$65,283.24	$4,211.82
1986	27.50	$5,285.14	43.00	15.50	0.3605	1.0000	$1,905.11	$122.91
1985	28.50	$27,703.98	44.00	15.50	0.3523	1.0000	$9,759.36	$629.64
1984	29.50	$4,682.02	45.00	15.50	0.3444	1.0000	$1,612.70	$104.04
1983	30.50	$6,856.49	46.00	15.50	0.3370	1.0000	$2,310.34	$149.05
1979	34.50	$9,167.39	50.00	15.50	0.3100	1.0000	$2,841.89	$183.35
1976	37.50	$26,289.91	53.00	15.50	0.2925	1.0000	$7,688.56	$496.04
1975	38.50	$4,706.82	54.00	15.50	0.2870	1.0000	$1,351.03	$87.16
1974	39.50	$54,449.11	55.00	15.50	0.2818	1.0000	$15,344.75	$989.98
1973	40.50	$4,931.00	56.00	15.50	0.2768	1.0000	$1,364.83	$88.05
1972	41.50	$1,610.12	57.00	15.50	0.2719	1.0000	$437.84	$28.25
1970	43.50	$10,995.92	59.00	15.50	0.2627	1.0000	$2,888.76	$186.37
1969	44.50	$1,987.32	60.00	15.50	0.2583	1.0000	$513.39	$33.12
1968	45.50	$1,105.85	61.00	15.50	0.2541	1.0000	$280.99	$18.13
1967	46.50	$691.96	62.00	15.50	0.2500	1.0000	$172.99	$11.16
1966	47.50	$15,757.58	63.00	15.50	0.2460	1.0000	$3,876.86	$250.12
1965	48.50	$16,049.55	64.00	15.50	0.2422	1.0000	$3,887.00	$250.77
1964	49.50	$4,355.04	65.00	15.50	0.2385	1.0000	$1,038.51	$67.00
.963	50.50	$4,165.48	66.00	15.50	0.2348	1.0000	$978.26	$63.11
1962	51.50	$1,064.55	67.00	15.50	0.2313	1.0000	$246.28	$15.89
1961	52.50	$184.00	68.00	15.50	0.2279	1.0000	$41.94	$2.71

Generation Arrangement Report

Account: MTED 101/6-39020 York Ser Ctr
Dispersion: 80.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1960	53.50	$3,025.82	69.00	15.50	0.2246	1.0000	$679.71	$43.85
1959	54.50	$3,645.28	70.00	15.50	0.2214	1.0000	$807.17	$52.08
1958	55.50	$3,994.28	71.00	15.50	0.2183	1.0000	$871.99	$56.26
1957	56.50	$3,879.23	72.00	15.50	0.2153	1.0000	$835.11	$53.88
1956	57.50	$21,556.65	73.00	15.50	0.2123	1.0000	$4,577.10	$295.30
1954	59.50	$4,120.40	75.00	15.50	0.2067	1.0000	$851.55	$54.94
1953	60.50	$79,119.34	76.00	15.50	0.2039	1.0000	$16,136.18	$1,041.04
1952	61.50	$280.97	77.00	15.50	0.2013	1.0000	$56.56	$3.65
1947	66.50	$28.66	80.00	13.50	0.1688	1.0000	$4.84	$0.36
1946	67.50	$308.77	80.00	12.50	0.1563	1.0000	$48.25	$3.86
1943	70.50	$8,942.02	80.00	9.50	0.1188	1.0000	$1,061.86	$111.78
1941	72.50	$47.48	80.00	7.50	0.0938	1.0000	$4.45	$0.59
1931	82.50	$80.56	0.00	0.00	0.0000	0.0000	$0.00	$0.00
1929	84.50	$3,678.88	0.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	87.50	$2,086.73	0.00	0.00	0.0000	0.0000	$0.00	$0.00
		$1,855,578.29	37.05	15.42	0.4167	1.0000	$773,177.56	$49,926.79

Remaining Life Depreciation Accrual

Account: MTED 101/6-39110 Office Furniture
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$16,629,980.08	3.16	$685,871.26	4.124306%	31.615735%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($1,194,710.59)	0.50	($29,867.76)	2.500000%	
Total:	$16,629,980.08 *		$656,003.50	3.944704%	30.238959%
Average:	$16,032,624.79		$656,003.50	4.091679%	41.729357%
Grand Total:	$16,629,980.08 *		$656,003.50	3.944704%	30.238959%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39110 Office Furniture
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$16,629,980.08	$14,460,581.63	0.8695	$2,169,398.45	0.1305
Computed	$16,629,980.08	$13,999,963.82	0.8419	$2,630,016.26	0.1581
Difference		$460,617.81	0.0277	($460,617.81)	-0.0277

Generation Arrangement Report

Account: MTED 101/6-39110 Office Furniture
Dispersion: 20.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$40,510.71	20.00	19.50	0.9750	1.0000	$39,497.94	$2,025.54
2012	1.50	$4,213.87	20.00	18.50	0.9250	1.0000	$3,897.83	$210.69
2011	2.50	$10,807.00	20.00	17.50	0.8750	1.0000	$9,456.13	$540.35
2009	4.50	$257,460.96	20.00	15.50	0.7750	1.0000	$199,532.24	$12,873.05
2008	5.50	$94,958.92	20.00	14.50	0.7250	1.0000	$68,845.22	$4,747.95
2007	6.50	$24,446.63	20.00	13.50	0.6750	1.0000	$16,501.48	$1,222.33
2006	7.50	$68,051.18	20.00	12.50	0.6250	1.0000	$42,531.99	$3,402.56
2005	8.50	$1,362,497.84	20.00	11.50	0.5750	1.0000	$783,436.26	$68,124.89
2004	9.50	$160,514.97	20.00	10.50	0.5250	1.0000	$84,270.36	$8,025.75
2003	10.50	$49,106.79	20.00	9.50	0.4750	1.0000	$23,325.73	$2,455.34
2002	11.50	$10,607.41	20.00	8.50	0.4250	1.0000	$4,508.15	$530.37
2001	12.50	$64,785.26	20.00	7.50	0.3750	1.0000	$24,294.47	$3,239.26
2000	13.50	$329,349.43	20.00	6.50	0.3250	1.0000	$107,038.56	$16,467.47
1999	14.50	$535,234.72	20.00	5.50	0.2750	1.0000	$147,189.55	$26,761.74
1998	15.50	$1,595,650.35	20.00	4.50	0.2250	1.0000	$359,021.33	$79,782.52
1997	16.50	$1,092,563.60	20.00	3.50	0.1750	1.0000	$191,198.63	$54,628.18
1996	17.50	$3,418,627.46	20.00	2.50	0.1250	1.0000	$427,328.43	$170,931.37
1995	18.50	$910,322.75	20.00	1.50	0.0750	1.0000	$68,274.21	$45,516.14
1994	19.50	$1,194,710.59	20.00	0.50	0.0250	1.0000	$29,867.76	$59,735.53
1993	20.50	$695,889.18	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1992	21.50	$454,144.45	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1991	22.50	$442,317.42	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1990	23.50	$561,178.24	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1989	24.50	$498,097.92	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1988	25.50	$272,101.58	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1987	26.50	$1,180,801.97	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	27.50	$394,534.16	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1985	28.50	$627,355.88	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1984	29.50	$255,054.26	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1983	30.50	$3,687.70	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1982	31.50	$6,172.52	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1981	32.50	$2,249.64	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1980	33.50	$1,967.81	20.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

Account: MTED 101/6-39110 Office Furniture
Dispersion: 20.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1979	34.50	$1,448.33	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1978	35.50	$1,222.43	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1977	36.50	$1,182.51	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1976	37.50	$1,547.51	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1975	38.50	$271.56	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1974	39.50	$711.27	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	40.50	$500.20	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	41.50	$593.88	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1971	42.50	$1,230.10	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1970	43.50	$272.52	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1969	44.50	$139.19	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1968	45.50	$131.65	20.00	0.00	0.0000	0.0000	$0.00	$0.00
'967	46.50	$78.60	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1966	47.50	$69.64	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1965	48.50	$73.66	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1964	49.50	$45.72	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1963	50.50	$64.88	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	51.50	$64.90	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1961	52.50	$68.82	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1960	53.50	$53.35	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1959	54.50	$54.15	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1958	55.50	$80.59	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1957	56.50	$61.86	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1956	57.50	$35.54	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1955	58.50	$1.52	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1954	59.50	$0.88	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1953	60.50	$0.68	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1952	61.50	$0.35	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1951	62.50	$0.50	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1950	63.50	$0.06	20.00	0.00	0.0000	0.0000	$0.00	$0.00
949	64.50	$0.06	20.00	0.00	0.0000	0.0000	$0.00	$0.00
		$16,629,980.08	20.00	3.16	0.1581	1.0000	$2,630,016.26	$561,221.02

Remaining Life Depreciation Accrual

Account: MTED 101/6-39115 Office Machines
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 10.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$5,920,633.10	0.00	$0.00	0.000000%	
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$5,920,633.10 *		$0.00	0.000000%	0.000000%
Average:	$5,920,633.10		$0.00	0.000000%	0.000000%
Grand Total:	$5,920,633.10 *		$0.00	0.000000%	

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39115 Office Machines
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 10 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$5,920,633.10	$5,920,633.10	1.0000	$0.00	0.0000
Computed	$5,920,633.10	$5,920,633.10	1.0000	$0.00	0.0000
Difference		$0.00	0.0000	$0.00	0.0000

Generation Arrangement Report

Account: MTED 101/6-39115 Office Machines
Dispersion: 10.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2000	13.50	$5,264.22	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1998	15.50	$239,217.03	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1997	16.50	$898,198.22	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1996	17.50	$456,266.52	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1995	18.50	$333,547.45	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1994	19.50	$109,384.16	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1993	20.50	$74,065.51	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1992	21.50	$266,082.61	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1991	22.50	$761,400.65	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1990	23.50	$122,295.80	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1989	24.50	$293,748.72	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1988	25.50	$170,041.01	10.00	0.00	0.0000	0.0000	$0.00	$0.00
'987	26.50	$1,034,119.22	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	27.50	$367,593.23	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1985	28.50	$283,464.82	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1984	29.50	$332,790.93	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1983	30.50	$173,153.00	10.00	0.00	0.0000	0.0000	$0.00	$0.00
		$5,920,633.10	0.00	0.00	0.0000	1.0000	$0.00	$0.00

Remaining Life Depreciation Accrual

Account: MTED 101/6-392 Transportation equip
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 10.00 - L3
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$268,209.32	7.62	$25,747.13	9.599641%	13.126724%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($3,087.05)	0.50	($154.35)	4.999919%	
Total:	$268,209.32 *		$25,592.78	9.542093%	13.048031%
Average:	$266,665.80		$25,592.78	9.597325%	13.151526%
Grand Total:	$268,209.32 *		$25,592.78	9.542093%	13.048031%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-392 Transportation equip
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 10 - L3
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$268,209.32	$72,066.45	0.2687	$196,142.87	0.7313
Computed	$268,209.32	$63,886.21	0.2382	$204,323.11	0.7618
Difference		$8,180.24	0.0305	($8,180.24)	-0.0305

Generation Arrangement Report

Account: MTED 101/6-392 Transportation equip
Dispersion: 10.00 - L3

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$97,011.29	10.00	9.50	0.9500	1.0000	$92,160.73	$9,701.13
2010	3.50	$166,404.13	10.00	6.58	0.6577	1.0000	$109,437.19	$16,640.41
2009	4.50	$4,793.90	10.00	5.68	0.5685	1.0000	$2,725.20	$479.39
		$268,209.32	10.00	7.62	0.7618	1.0000	$204,323.11	$26,820.93

Remaining Life Depreciation Accrual

Account: MTED 101/6-39240 Pole Trailers
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25.00 - S1
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$711,524.79	10.55	$24,374.59	3.425684%	9.480643%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($41,192.93)	0.50	($823.86)	2.000003%	
Total:	$711,524.79 *		$23,550.73	3.309897%	9.160198%
Average:	$690,928.33		$23,550.73	3.408564%	9.957940%
Grand Total:	$711,524.79 *		$23,550.73	3.309897%	9.160198%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39240 Pole Trailers
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25 - S1
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$711,524.79	$454,426.25	0.6387	$257,098.54	0.3613
Computed	$711,524.79	$411,323.71	0.5781	$300,201.08	0.4219
Difference		$43,102.54	0.0606	($43,102.54)	-0.0606

Generation Arrangement Report

Account: MTED 101/6-39240 Pole Trailers
Dispersion: 25.00 - S1
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2000	13.50	$4,952.00	25.00	13.87	0.5546	1.0000	$2,746.55	$198.08
1999	14.50	$91,590.59	25.00	13.25	0.5302	1.0000	$48,560.24	$3,663.62
1998	15.50	$49,864.56	25.00	12.67	0.5067	1.0000	$25,266.30	$1,994.58
1997	16.50	$218,827.80	25.00	12.10	0.4841	1.0000	$105,935.87	$8,753.11
1994	19.50	$74,643.07	25.00	10.53	0.4212	1.0000	$31,439.17	$2,985.72
1993	20.50	$20,312.08	25.00	10.04	0.4017	1.0000	$8,158.78	$812.48
1992	21.50	$85,257.87	25.00	9.57	0.3828	1.0000	$32,636.56	$3,410.31
1990	23.50	$70,789.02	25.00	8.67	0.3468	1.0000	$24,552.30	$2,831.56
1988	25.50	$3,874.92	25.00	7.83	0.3130	1.0000	$1,212.90	$155.00
1987	26.50	$23,064.02	25.00	7.42	0.2968	1.0000	$6,845.76	$922.56
1986	27.50	$3,500.12	25.00	7.03	0.2811	1.0000	$983.75	$140.00
1985	28.50	$3,724.85	25.00	6.64	0.2657	1.0000	$989.76	$148.99
1984	29.50	$12,644.70	25.00	6.27	0.2508	1.0000	$3,170.83	$505.79
1983	30.50	$17,629.65	25.00	5.90	0.2362	1.0000	$4,163.64	$705.19
1982	31.50	$4,232.00	25.00	5.55	0.2219	1.0000	$939.19	$169.28
1979	34.50	$4,192.44	25.00	4.53	0.1811	1.0000	$759.07	$167.70
1976	37.50	$340.00	25.00	3.57	0.1426	1.0000	$48.50	$13.60
1975	38.50	$3,131.00	25.00	3.26	0.1303	1.0000	$408.06	$125.24
1972	41.50	$5,040.33	25.00	2.37	0.0947	1.0000	$477.31	$201.61
1971	42.50	$3,043.50	25.00	2.08	0.0832	1.0000	$253.36	$121.74
1970	43.50	$6,936.97	25.00	1.80	0.0720	1.0000	$499.52	$277.48
1968	45.50	$3,057.91	25.00	1.26	0.0503	1.0000	$153.66	$122.32
1951	62.50	$875.39	25.00	0.00	0.0000	0.0000	$0.00	$0.00
		$711,524.79	25.00	10.55	0.4219	1.0000	$300,201.08	$28,425.98

Remaining Life Depreciation Accrual

Account: MTED 101/6-39250 Van Trailers
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25.00 - S1
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$87,236.99	12.08	$690.95	0.792040%	8.279192%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($3,316.17)	0.50	($66.32)	1.999897%	
Total:	$87,236.99 *		$624.63	0.716017%	7.484525%
Average:	$85,578.91		$624.63	0.729890%	9.340208%
Grand Total:	$87,236.99 *		$624.63	0.716017%	7.484525%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39250 Van Trailers
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25 - S1
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$87,236.99	$78,891.35	0.9043	$8,345.64	0.0957
Computed	$87,236.99	$45,089.40	0.5169	$42,147.59	0.4831
Difference		$33,801.95	0.3875	($33,801.95)	-0.3875

Generation Arrangement Report

Account: MTED 101/6-39250 Van Trailers
Dispersion: 25.00 - S1

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1997	16.50	$85,895.98	25.00	12.10	0.4841	1.0000	$41,582.77	$3,435.84
1994	19.50	$1,341.01	25.00	10.53	0.4212	1.0000	$564.82	$53.64
		$87,236.99	25.00	12.08	0.4831	1.0000	$42,147.59	$3,489.48

Remaining Life Depreciation Accrual

Account: MTED 101/6-393 Stores Equipment
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$1,411,421.83	1.20	$12,423.86	0.880237%	83.491759%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($104,649.50)	0.50	($2,616.24)	2.500002%	
Total:	$1,411,421.83 *		$9,807.62	0.694875%	65.909903%
Average:	$1,359,097.08		$9,807.62	0.721627%	-26.192475%
Grand Total:	$1,411,421.83 *		$9,807.62	0.694875%	65.909903%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-393 Stores Equipment
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Depreciation Reserve Amount	Ratio	Net Plant Amount	Ratio
Recorded	$1,411,421.83	$1,396,541.49	0.9895	$14,880.34	0.0105
Computed	$1,411,421.83	$1,326,897.21	0.9401	$84,524.62	0.0599
Difference		$69,644.28	0.0493	($69,644.28)	-0.0493

Generation Arrangement Report

Account: MTED 101/6-393 Stores Equipment
Dispersion: 20.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2001	12.50	$25,412.19	20.00	7.50	0.3750	1.0000	$9,529.57	$1,270.61
2000	13.50	$17,476.87	20.00	6.50	0.3250	1.0000	$5,679.98	$873.84
1999	14.50	$210,539.16	20.00	5.50	0.2750	1.0000	$57,898.27	$10,526.96
1998	15.50	$35,405.13	20.00	4.50	0.2250	1.0000	$7,966.15	$1,770.26
1995	18.50	$11,125.41	20.00	1.50	0.0750	1.0000	$834.41	$556.27
1994	19.50	$104,649.50	20.00	0.50	0.0250	1.0000	$2,616.24	$5,232.48
1993	20.50	$14,066.18	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1992	21.50	$66,247.42	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1991	22.50	$55,762.99	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1990	23.50	$579,497.73	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1989	24.50	$37,020.70	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1988	25.50	$20,603.17	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1987	26.50	$32,459.04	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	27.50	$30,501.80	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1985	28.50	$12,114.16	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1984	29.50	$62,704.66	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1983	30.50	$28,272.74	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1982	31.50	$7,548.84	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1981	32.50	$2,555.51	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1980	33.50	$385.22	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1978	35.50	$1,355.68	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1977	36.50	$14,277.23	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1976	37.50	$5,568.81	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1975	38.50	$2,290.95	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1974	39.50	$7,485.81	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	40.50	$4,979.85	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	41.50	$7,858.35	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1971	42.50	$467.88	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1970	43.50	$2,132.94	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1969	44.50	$3,902.48	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1968	45.50	$4,195.27	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1967	46.50	$2,558.16	20.00	0.00	0.0000	0.0000	$0.00	$0.00
		$1,411,421.83	20.00	1.20	0.0599	1.0000	$84,524.62	$20,230.41

05/30/2014

Remaining Life Depreciation Accrual

Account: MTED 101/6-394 Tools shop garage
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$11,612,990.40	10.38	$487,026.48	4.193808%	9.631497%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($446,051.26)	0.50	($8,921.03)	2.000001%	
Total:	$11,612,990.40 *		$478,105.45	4.116988%	9.455074%
Average:	$11,389,964.77		$478,105.45	4.197603%	9.891339%
Grand Total:	$11,612,990.40 *		$478,105.45	4.116988%	9.455074%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-394 Tools shop garage
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$11,612,990.40	$6,556,388.32	0.5646	$5,056,602.08	0.4354
Computed	$11,612,990.40	$6,790,068.06	0.5847	$4,822,922.34	0.4153
Difference		($233,679.74)	-0.0201	$233,679.74	0.0201

Generation Arrangement Report

Account: MTED 101/6-394 Tools shop garage
Dispersion: 25.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$1,755,350.68	25.00	24.50	0.9800	1.0000	$1,720,243.67	$70,214.03
2012	1.50	$158,090.37	25.00	23.50	0.9400	1.0000	$148,604.95	$6,323.61
2011	2.50	$146,279.76	25.00	22.50	0.9000	1.0000	$131,651.78	$5,851.19
2010	3.50	$368,739.77	25.00	21.50	0.8600	1.0000	$317,116.20	$14,749.59
2009	4.50	$169,945.22	25.00	20.50	0.8200	1.0000	$139,355.08	$6,797.81
2008	5.50	$930,814.00	25.00	19.50	0.7800	1.0000	$726,034.92	$37,232.56
2007	6.50	$79,065.30	25.00	18.50	0.7400	1.0000	$58,508.32	$3,162.61
2006	7.50	$301,929.84	25.00	17.50	0.7000	1.0000	$211,350.89	$12,077.19
2005	8.50	($34,203.54)	25.00	16.50	0.6600	1.0000	($22,574.34)	($1,368.14)
2003	10.50	$152,361.45	25.00	14.50	0.5800	1.0000	$88,369.64	$6,094.46
2002	11.50	$201,085.58	25.00	13.50	0.5400	1.0000	$108,586.21	$8,043.42
2001	12.50	$392,750.60	25.00	12.50	0.5000	1.0000	$196,375.30	$15,710.02
2000	13.50	$338,417.49	25.00	11.50	0.4600	1.0000	$155,672.05	$13,536.70
1999	14.50	$163,512.10	25.00	10.50	0.4200	1.0000	$68,675.08	$6,540.48
1998	15.50	$1,086,128.46	25.00	9.50	0.3800	1.0000	$412,728.81	$43,445.14
1997	16.50	$307,177.56	25.00	8.50	0.3400	1.0000	$104,440.37	$12,287.10
1996	17.50	$163,182.73	25.00	7.50	0.3000	1.0000	$48,954.82	$6,527.31
1995	18.50	$184,446.60	25.00	6.50	0.2600	1.0000	$47,956.12	$7,377.86
1994	19.50	$185,679.97	25.00	5.50	0.2200	1.0000	$40,849.59	$7,427.20
1993	20.50	$220,993.69	25.00	4.50	0.1800	1.0000	$39,778.86	$8,839.75
1992	21.50	$216,563.32	25.00	3.50	0.1400	1.0000	$30,318.86	$8,662.53
1991	22.50	$157,912.55	25.00	2.50	0.1000	1.0000	$15,791.26	$6,316.50
1990	23.50	$420,214.40	25.00	1.50	0.0600	1.0000	$25,212.86	$16,808.58
1989	24.50	$446,051.26	25.00	0.50	0.0200	1.0000	$8,921.03	$17,842.05
1988	25.50	$195,036.42	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1987	26.50	$372,831.89	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	27.50	$315,949.61	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1985	28.50	$373,676.09	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1984	29.50	$279,597.05	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1983	30.50	$197,066.35	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1982	31.50	$105,742.51	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1981	32.50	$32,811.39	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1980	33.50	$31,356.78	25.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

Account: MTED 101/6-394 Tools shop garage
Dispersion: 25.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1979	34.50	$135,221.17	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1978	35.50	$114,335.27	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1977	36.50	$101,886.74	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1976	37.50	$72,666.38	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1975	38.50	$29,718.10	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1974	39.50	$102,542.42	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	40.50	$141,435.09	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	41.50	$55,326.82	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1971	42.50	$37,314.04	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1970	43.50	$45,792.78	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1969	44.50	$62,983.18	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1968	45.50	$48,908.46	25.00	0.00	0.0000	0.0000	$0.00	$0.00
'967	46.50	$43,432.96	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1966	47.50	$71,723.98	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1965	48.50	$39,015.13	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1964	49.50	$44,296.39	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1963	50.50	$32,575.40	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	51.50	$17,258.84	25.00	0.00	0.0000	0.0000	$0.00	$0.00
		$11,612,990.40	25.00	10.38	0.4153	1.0000	$4,822,922.34	$340,499.57

Remaining Life Depreciation Accrual

Account: MTED 101/6-395 Laboratory equip
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$3,047,683.99	0.85	$32.18	0.001056%	100.000000%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($32,802.91)	0.50	($820.07)	2.499992%	
Total:	$3,047,683.99 *		($787.89)	-0.025852%	2448.384089%
Average:	$3,031,282.54		($787.89)	-0.025992%	4.813225%
Grand Total:	$3,047,683.99 *		($787.89)	-0.025852%	2448.384089%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-395 Laboratory equip
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$3,047,683.99	$3,047,651.81	1.0000	$32.18	0.0000
Computed	$3,047,683.99	$2,918,725.52	0.9577	$128,958.47	0.0423
Difference		$128,926.29	0.0423	($128,926.29)	-0.0423

Generation Arrangement Report

Account: MTED 101/6-395 Laboratory equip
Dispersion: 20.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2009	4.50	($918.29)	20.00	15.50	0.7750	1.0000	($711.67)	($45.91)
2008	5.50	$86,620.60	20.00	14.50	0.7250	1.0000	$62,799.94	$4,331.03
2000	13.50	$698.02	20.00	6.50	0.3250	1.0000	$226.86	$34.90
1997	16.50	$159,740.25	20.00	3.50	0.1750	1.0000	$27,954.54	$7,987.01
1996	17.50	$234,523.10	20.00	2.50	0.1250	1.0000	$29,315.39	$11,726.16
1995	18.50	$114,044.69	20.00	1.50	0.0750	1.0000	$8,553.35	$5,702.23
1994	19.50	$32,802.91	20.00	0.50	0.0250	1.0000	$820.07	$1,640.15
1993	20.50	$96,728.35	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1992	21.50	$128,933.21	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1991	22.50	$232,205.59	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1990	23.50	$204,185.93	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1989	24.50	$162,751.76	20.00	0.00	0.0000	0.0000	$0.00	$0.00
'988	25.50	$274,767.81	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1987	26.50	$403,783.63	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	27.50	$228,915.36	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1985	28.50	$86,047.11	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1984	29.50	$257,305.72	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1983	30.50	$148,714.64	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1982	31.50	$17,913.69	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1981	32.50	$6,777.40	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1980	33.50	$8,278.86	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1979	34.50	$45,555.79	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1978	35.50	$38,959.12	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1977	36.50	$1,973.32	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1976	37.50	$10,601.33	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1975	38.50	$7,441.27	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1974	39.50	$16,355.06	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	40.50	$11,733.40	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	41.50	$6,889.08	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1971	42.50	$5,901.54	20.00	0.00	0.0000	0.0000	$0.00	$0.00
.970	43.50	$11,018.24	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1969	44.50	$6,435.50	20.00	0.00	0.0000	0.0000	$0.00	$0.00
		$3,047,683.99	20.00	0.85	0.0423	1.0000	$128,958.47	$31,375.56

Remaining Life Depreciation Accrual

Account: MTED 101/6-396 Power operated equip
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20.00 - L0.5
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$751,657.85	10.79	$12,934.64	1.720815%	9.265490%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($58,689.67)	0.50	($1,467.24)	2.499997%	
Total:	$751,657.85 *		$11,467.40	1.525615%	8.214460%
Average:	$722,313.02		$11,467.40	1.587595%	10.400767%
Grand Total:	$751,657.85 *		$11,467.40	1.525615%	8.214460%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-396 Power operated equip
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20 - L0.5
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$751,657.85	$612,057.66	0.8143	$139,600.19	0.1857
Computed	$751,657.85	$346,035.59	0.4604	$405,622.26	0.5396
Difference		$266,022.07	0.3539	($266,022.07)	-0.3539

Generation Arrangement Report

Account: MTED 101/6-396 Power operated equip
Dispersion: 20.00 - L0.5

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$108,843.59	20.00	19.56	0.9778	1.0000	$106,429.70	$5,442.18
2007	6.50	$12,318.22	20.00	15.51	0.7755	1.0000	$9,552.83	$615.91
2002	11.50	$75,143.40	20.00	13.29	0.6647	1.0000	$49,951.06	$3,757.17
2001	12.50	$36,996.86	20.00	12.92	0.6460	1.0000	$23,901.48	$1,849.84
2000	13.50	$96,540.56	20.00	12.56	0.6279	1.0000	$60,614.26	$4,827.03
1998	15.50	($35,656.68)	20.00	11.86	0.5930	1.0000	($21,144.81)	($1,782.83)
1996	17.50	$23,509.02	20.00	11.20	0.5600	1.0000	$13,165.82	$1,175.45
1993	20.50	$140,207.69	20.00	10.28	0.5139	1.0000	$72,046.51	$7,010.38
1991	22.50	$887.85	20.00	9.70	0.4852	1.0000	$430.75	$44.39
1988	25.50	$6,437.00	20.00	8.90	0.4449	1.0000	$2,863.99	$321.85
1986	27.50	$11,289.00	20.00	8.40	0.4200	1.0000	$4,740.95	$564.45
1982	31.50	$27,454.00	20.00	7.48	0.3741	1.0000	$10,270.27	$1,372.70
1979	34.50	$2,226.00	20.00	6.86	0.3431	1.0000	$763.74	$111.30
1978	35.50	$31,361.56	20.00	6.67	0.3334	1.0000	$10,457.33	$1,568.08
1977	36.50	$34,320.49	20.00	6.48	0.3241	1.0000	$11,122.46	$1,716.02
1974	39.50	$604.00	20.00	5.96	0.2979	1.0000	$179.95	$30.20
1973	40.50	$26,241.51	20.00	5.80	0.2899	1.0000	$7,606.41	$1,312.08
1972	41.50	$88,746.00	20.00	5.64	0.2821	1.0000	$25,037.16	$4,437.30
1971	42.50	$64,187.78	20.00	5.49	0.2747	1.0000	$17,632.38	$3,209.39
		$751,657.85	20.00	10.79	0.5396	1.0000	$405,622.26	$37,582.89

Remaining Life Depreciation Accrual

Account: MTED 101/6-397 Communication Equipt
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20.00 - R0.5
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$33,964,326.46	10.06	$1,023,303.82	3.012878%	9.941215%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($1,989,229.01)	0.50	($49,730.73)	2.500000%	
Total:	$33,964,326.46 *		$973,573.09	2.866458%	9.458089%
Average:	$32,969,711.96		$973,573.09	2.952932%	10.469727%
Grand Total:	$33,964,326.46 *		$973,573.09	2.866458%	9.458089%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-397 Communication Equipt
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20 - R0.5
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$33,964,326.46	$23,670,777.27	0.6969	$10,293,549.19	0.3031
Computed	$33,964,326.46	$16,881,742.30	0.4970	$17,082,584.16	0.5030
Difference		$6,789,034.97	0.1999	($6,789,034.97)	-0.1999

Generation Arrangement Report

Account: MTED 101/6-397 Communication Equipt
Dispersion: 20.00 - R0.5
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$1,254,003.90	20.00	19.69	0.9845	1.0000	$1,234,543.39	$62,700.20
2012	1.50	$116.24	20.00	19.07	0.9536	1.0000	$110.85	$5.81
2011	2.50	$161,097.25	20.00	18.46	0.9229	1.0000	$148,683.22	$8,054.86
2010	3.50	$205,964.33	20.00	17.85	0.8925	1.0000	$183,820.10	$10,298.22
2009	4.50	$3,088,976.98	20.00	17.24	0.8622	1.0000	$2,663,408.37	$154,448.85
2008	5.50	$1,574,554.25	20.00	16.64	0.8321	1.0000	$1,310,233.59	$78,727.71
2005	8.50	$90,166.59	20.00	14.86	0.7429	1.0000	$66,981.81	$4,508.33
2002	11.50	$244,698.70	20.00	13.12	0.6558	1.0000	$160,483.41	$12,234.94
2001	12.50	$104,311.65	20.00	12.55	0.6275	1.0000	$65,460.78	$5,215.58
2000	13.50	$519,159.05	20.00	11.99	0.5997	1.0000	$311,349.42	$25,957.95
1999	14.50	$101,351.31	20.00	11.45	0.5724	1.0000	$58,010.00	$5,067.57
1998	15.50	$1,530,328.61	20.00	10.91	0.5455	1.0000	$834,864.35	$76,516.43
'997	16.50	$950,150.44	20.00	10.39	0.5193	1.0000	$493,394.91	$47,507.52
1996	17.50	($1,926,514.18)	20.00	9.87	0.4936	1.0000	($950,863.06)	($96,325.71)
1995	18.50	$10,229,039.42	20.00	9.37	0.4684	1.0000	$4,791,719.24	$511,451.97
1994	19.50	$309,972.84	20.00	8.88	0.4439	1.0000	$137,597.47	$15,498.64
1993	20.50	$809,280.72	20.00	8.40	0.4199	1.0000	$339,847.65	$40,464.04
1992	21.50	$9,074,733.78	20.00	7.93	0.3965	1.0000	$3,598,409.31	$453,736.69
1991	22.50	$664,286.24	20.00	7.47	0.3737	1.0000	$248,235.24	$33,214.31
1990	23.50	$2,344,324.93	20.00	7.03	0.3514	1.0000	$823,759.43	$117,216.25
1989	24.50	$871,137.12	20.00	6.59	0.3296	1.0000	$287,101.80	$43,556.86
1988	25.50	$210,108.28	20.00	6.16	0.3082	1.0000	$64,763.34	$10,505.41
1987	26.50	$53,352.94	20.00	5.75	0.2873	1.0000	$15,330.25	$2,667.65
1986	27.50	$211,458.29	20.00	5.34	0.2668	1.0000	$56,418.85	$10,572.91
1985	28.50	$199,330.05	20.00	4.93	0.2466	1.0000	$49,155.83	$9,966.50
1984	29.50	$94,236.58	20.00	4.53	0.2266	1.0000	$21,358.12	$4,711.83
1983	30.50	$103,298.41	20.00	4.14	0.2068	1.0000	$21,365.65	$5,164.92
1982	31.50	$27,098.35	20.00	3.74	0.1871	1.0000	$5,069.78	$1,354.92
1981	32.50	$15,995.84	20.00	3.35	0.1673	1.0000	$2,675.43	$799.79
1980	33.50	$11,286.51	20.00	2.94	0.1472	1.0000	$1,661.48	$564.33
.979	34.50	$188,830.96	20.00	2.54	0.1268	1.0000	$23,937.05	$9,441.55
1978	35.50	$48,736.90	20.00	2.11	0.1057	1.0000	$5,153.04	$2,436.85
1977	36.50	$82,488.23	20.00	1.68	0.0839	1.0000	$6,923.18	$4,124.41

Generation Arrangement Report

Account: MTED 101/6-397 Communication Equipt
Dispersion: 20.00 - R0.5

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1976	37.50	$4,953.43	20.00	1.23	0.0613	1.0000	$303.67	$247.67
1975	38.50	$16,229.07	20.00	0.77	0.0384	1.0000	$622.80	$811.45
1974	39.50	$39,907.58	20.00	0.35	0.0174	1.0000	$694.43	$1,995.38
1973	40.50	$58,242.70	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	41.50	$150,401.68	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1971	42.50	$50,491.08	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1970	43.50	$2,793.19	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1969	44.50	$32,425.78	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1968	45.50	$18,301.74	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1967	46.50	$7,997.61	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1966	47.50	$16,615.59	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1965	48.50	$25,429.47	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1964	49.50	$17,911.66	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1963	50.50	$40,255.19	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	51.50	$4,911.73	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1961	52.50	$65.01	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1960	53.50	$5,474.48	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1959	54.50	$1,070.15	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1958	55.50	$101.78	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1957	56.50	$187.09	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1956	57.50	$1,378.86	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1955	58.50	$1,899.18	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1954	59.50	$1,704.79	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1953	60.50	$827.16	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1951	62.50	$1,825.22	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1950	63.50	$2,832.59	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1948	65.50	$12,189.30	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1947	66.50	$487.04	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1935	78.50	$30.93	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	87.50	$23.87	20.00	0.00	0.0000	0.0000	$0.00	$0.00
		$33,964,326.46	20.00	10.06	0.5030	1.0000	$17,082,584.16	$1,675,422.58

Remaining Life Depreciation Accrual

Account: MTED 101/6-398 Miscellaneous equipt
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$2,586,559.95	2.03	$47,540.14	1.837968%	49.226189%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($65,392.51)	0.50	($1,634.81)	2.499996%	
Total:	$2,586,559.95 *		$45,905.33	1.774764%	47.533399%
Average:	$2,553,863.70		$45,905.33	1.797486%	71.863348%
Grand Total:	$2,586,559.95 *		$45,905.33	1.774764%	47.533399%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-398 Miscellaneous equipt
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$2,586,559.95	$2,489,985.05	0.9627	$96,574.90	0.0373
Computed	$2,586,559.95	$2,323,838.02	0.8984	$262,721.93	0.1016
Difference		$166,147.03	0.0642	($166,147.03)	-0.0642

Generation Arrangement Report

Account: MTED 101/6-398 Miscellaneous equipt
Dispersion: 20.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$11,519.21	20.00	19.50	0.9750	1.0000	$11,231.23	$575.96
2012	1.50	$886.89	20.00	18.50	0.9250	1.0000	$820.37	$44.34
2011	2.50	$30,044.90	20.00	17.50	0.8750	1.0000	$26,289.29	$1,502.25
2007	6.50	$6,932.76	20.00	13.50	0.6750	1.0000	$4,679.61	$346.64
2003	10.50	$9,290.69	20.00	9.50	0.4750	1.0000	$4,413.08	$464.53
2002	11.50	$32,453.36	20.00	8.50	0.4250	1.0000	$13,792.68	$1,622.67
2001	12.50	$4,923.43	20.00	7.50	0.3750	1.0000	$1,846.29	$246.17
2000	13.50	$279,555.58	20.00	6.50	0.3250	1.0000	$90,855.56	$13,977.78
1999	14.50	$225,999.68	20.00	5.50	0.2750	1.0000	$62,149.91	$11,299.98
1998	15.50	$32,633.98	20.00	4.50	0.2250	1.0000	$7,342.65	$1,631.70
1997	16.50	$130,458.16	20.00	3.50	0.1750	1.0000	$22,830.18	$6,522.91
1996	17.50	$106,909.66	20.00	2.50	0.1250	1.0000	$13,363.71	$5,345.48
1995	18.50	$19,634.24	20.00	1.50	0.0750	1.0000	$1,472.57	$981.71
1994	19.50	$65,392.51	20.00	0.50	0.0250	1.0000	$1,634.81	$3,269.63
1993	20.50	$123,377.94	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1992	21.50	$7,878.45	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1991	22.50	$386,470.24	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1990	23.50	$133,275.60	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1989	24.50	$170,813.56	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1988	25.50	$151,319.90	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1987	26.50	$105,251.18	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	27.50	$49,320.40	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1985	28.50	$72,198.35	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1984	29.50	$271,649.70	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1983	30.50	$30,104.60	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1982	31.50	$81,890.19	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1981	32.50	$1,948.05	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1980	33.50	$19,354.88	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1979	34.50	$25,071.86	20.00	0.00	0.0000	0.0000	$0.00	$0.00
		$2,586,559.95	20.00	2.03	0.1016	1.0000	$262,721.93	$47,831.75

Remaining Life Depreciation Accrual

Account: MTED-101/6-39120
Scenario: Met Ed 2014 ADR 39120 PC
Dispersion: 4.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$2,194,187.95	0.84	$147,502.86	6.722435%	100.000000%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($275,835.27)	0.50	($34,479.41)	12.500000%	
Total:	$2,194,187.95 *		$113,023.45	5.151038%	76.624582%
Average:	$2,056,270.32		$113,023.45	5.496527%	1179.142378%
Grand Total:	$2,194,187.95 *		$113,023.45	5.151038%	76.624582%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED-101/6-39120
Scenario: Met Ed 2014 ADR 39120 PC
Dispersion: 4 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$2,194,187.95	$2,046,685.09	0.9328	$147,502.86	0.0672
Computed	$2,194,187.95	$1,732,696.52	0.7897	$461,491.43	0.2103
Difference		$313,988.57	0.1431	($313,988.57)	-0.1431

Generation Arrangement Report

Account: MTED-101/6-39120
Dispersion: 4.00 - SQ

erage Net Salvage Rate: 0.00%
uture Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$188,236.27	4.00	3.50	0.8750	1.0000	$164,706.74	$47,059.07
2012	1.50	($511.50)	4.00	2.50	0.6250	1.0000	($319.69)	($127.88)
2011	2.50	$700,333.27	4.00	1.50	0.3750	1.0000	$262,624.98	$175,083.32
2010	3.50	$275,835.27	4.00	0.50	0.1250	1.0000	$34,479.41	$68,958.82
2009	4.50	$248,107.52	4.00	0.00	0.0000	0.0000	$0.00	$0.00
2008	5.50	$782,187.12	4.00	0.00	0.0000	0.0000	$0.00	$0.00
		$2,194,187.95	4.00	0.84	0.2103	1.0000	$461,491.43	$290,973.33

Remaining Life Depreciation Accrual

Account: MTED-101/6-39125
Scenario: Met Ed 2014 ADR 39125 Info Sys
Dispersion: 10.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$2,314,954.79	7.68	$301,710.32	13.033098%	13.022402%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$2,314,954.79 *		$301,710.32	13.033098%	13.022402%
Average:	$2,314,954.79		$301,710.32	13.033098%	13.022402%
Grand Total:	$2,314,954.79 *		$301,710.32	13.033098%	13.022402%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED-101/6-39125
Scenario: Met Ed 2014 ADR 39125 Info Sys
Dispersion: 10 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$2,314,954.79	($1,901.39)	-0.0008	$2,316,856.18	1.0008
Computed	$2,314,954.79	$537,283.62	0.2321	$1,777,671.17	0.7679
Difference		($539,185.01)	-0.2329	$539,185.01	0.2329

Generation Arrangement Report

Account: MTED-101/6-39125
Dispersion: 10.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$207,275.38	10.00	9.50	0.9500	1.0000	$196,911.61	$20,727.54
2011	2.50	$2,107,679.41	10.00	7.50	0.7500	1.0000	$1,580,759.56	$210,767.94
		$2,314,954.79	10.00	7.68	0.7679	1.0000	$1,777,671.17	$231,495.48

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT VI-A:

"Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

A. Balance sheet in the form available."

RESPONSE:

See Met-Ed Exhibit RAD-54 Attachment A.

Metropolitan Edison Company
Balance Sheet

FERC Account	Assets and Other Debits	April 30, 2016	March 31, 2015	March 31, 2014	March 31, 2013
			(In thousands)		
	Utility Plant				
101-107	Total electric utility plant at original cost	$ 3,012,033	$ 2,890,357	$ 2,773,905	$ 2,703,573
108-110	Less: Accum. Provision for depreciation	1,055,494	1,001,528	959,316	929,077
120.1-120.4	Nuclear plant	-	-	-	-
120.5	Less: accum. provision for amortization of nuclear fuel	-	-	-	-
	Net utility plant	1,956,539	1,888,829	1,814,589	1,774,496
	Other Property and Investments				
121	Non-utility property	1,224	1,224	1,224	1,224
122	Prov. for depreciation of non-utility prop.	464	446	429	412
123.1	Investments in subsidiary companies	-	-	-	-
124	Other investments	49	49	59	46
125-8	Special funds	328,928	328,928	328,859	321,624
	Total other property and investments	329,737	329,755	329,713	322,482
	Current and Accrued Assets				
131	Cash	-	-	-	-
132-134	Special deposits	158	158	158	157
135	Working funds	-	-	-	-
136	Temporary cash investments	-	-	-	-
142	Customer accounts receivable	123,043	124,667	126,615	94,741
143	Other accounts receivable	6,040	6,040	6,893	7,770
144	Accum. provision for uncollectible accts	5,725	5,725	7,408	3,505
145	Notes receivable from associated companies	66,908	94,604	-	-
146	Receivables from associated companies	28,041	28,041	42,691	1,071
151	Fuel stock	-	-	-	-
154-163	Plant materials and operating supplies-electric	728	728	-	-
165	Prepayments	22,256	22,257	21,798	35,792
171	Interest and dividends receivable	-	-	-	-
172	Rents receivable	7,688	7,688	8,614	7,937
173	Accrued utility revenues	43,658	43,658	40,114	38,515
174	Misc. current and accrued assets	17,085	17,085	633	997
	Total current and accrued assets	309,880	339,201	240,106	183,475
	Deferred Debits				
181	Unamortized debt expense	5,278	6,218	3,603	3,786
182	Other regulatory assets	253,521	279,108	286,827	484,968
183	Preliminary survey and investigation charges	575	575	584	564
184	Clearing accounts	-	-	-	-
185	Temporary facilities	1,688	1,168	662	671
186	Miscellaneous deferred debits	413,016	406,667	427,254	427,365
188	Research and development expenditures	351	351	351	351
189	Unamortized loss on reacquired debt	1,720	-	2,382	4,025
190	Accumulated deferred income taxes	452,973	454,272	471,353	251,370
	Total deferred debits	1,129,121	1,148,360	1,193,015	1,173,100
	Total assets and other debits	$ 3,725,277	$ 3,706,144	$ 3,577,422	$ 3,453,553

Metropolitan Edison Company
Balance Sheet

FERC Account	Liabilities and Other Credits	April 30, 2016	March 31, 2015	March 31, 2014	March 31, 2013
			(In thousands)		
	Proprietary Capital				
201	Common stock issued	$ 827,802	$ 827,802	$ 827,740	$ 767,489
204	Preferred stock issued	-	-	-	-
207	Premium on capital stock	-	-	-	-
208	Other paid in capital	93	93	116	-
210	Gain on resale or cancellation of reacquired capital stock	-	-	-	-
214	Capital stock expense	-	-	-	-
216	Retained earnings	(10,133)	(12,550)	(22,115)	224
216.1	Unappropriated Undistributed Subsidiary Earnings	-	-	-	-
219	Accumulated other comprehensive income	(370)	3,770	12,150	21,172
	Total proprietary capital	817,392	819,114	817,892	788,885
	Long-Term Debt				
221	Bonds	200,000	200,000	28,500	28,500
224	Other long-term debt	750,000	750,000	750,000	850,000
225	Unamortized premium on long-term debt	-	-	-	-
226	Less: Unamortized discount on long-term debt	293	339	382	501
	Total long-term debt	949,707	949,661	778,118	877,999
227-230	**Other Non-Current Liabilities**	352,596	345,118	353,112	357,393
	Current and Accrued Liabilities	-	-	-	-
231	Notes payable	50,000	50,000	75,000	-
232	Accounts payable	56,468	56,468	55,449	21,031
233	Notes payable to associated companies	-	-	61,845	91,306
234	Accounts payable to associated companies	30,645	30,645	50,478	77,055
235	Customer deposits	20,925	20,925	21,452	15,044
236	Taxes accrued	45,237	54,998	9,811	16,208
237	Interest accrued	30,578	16,269	9,198	11,587
238	Dividends declared	-	-	-	-
241	Tax collections payable	348	348	390	342
242	Misc. current and accrued liabilities	15,253	17,291	19,942	16,171
243	Oblig. under capital leases-current	2,983	2,983	2,991	2,408
	Total current and accrued liabilities	252,437	249,926	306,556	251,152
	Deferred Credits				
252	Customer advances for construction	19	19	19	63
253	Other deferred credits	164,297	164,537	136,035	145,792
254	Other regulatory liabilities	145,564	137,494	140,450	136,772
255	Accum. deferred investment tax credits	4,813	5,208	5,521	5,919
256	Deferred gains on disposition of plant	-	-	-	-
257	Unamortized gain on reacquired debt	(317)	(161)	1,266	1,476
	Total deferred credits	314,376	307,096	283,292	290,022
	Accumulated Deferred Income Taxes				
282	Other property	552,440	552,220	555,752	542,609
283	Other	486,327	483,009	482,701	345,493
	Total accum. deferred income taxes	1,038,767	1,035,229	1,038,453	888,102
	Total liabilities and other credits	$ 3,725,277	$ 3,706,144	$ 3,577,422	$ 3,453,553

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT VI-B:

"Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

B. Statement of income."

RESPONSE:

See Met-Ed Exhibit RAD-55 Attachment A.

Metropolitan Edison Company
Comparative Income Statements

FERC Account		April 30, 2016	March 31, 2015	2014	2013
			(In thousands)		
Operating Revenues					
Electric Service Revenues					
440	Residential sales	$ 487,124	$ 495,246	$ 557,080	$ 571,437
442	Commercial sales	112,883	123,810	131,306	152,083
442	Industrial sales	51,258	50,866	45,471	68,019
444	Public street and highway lighting	5,410	5,141	5,252	7,015
445	Other sales to public authorities		-	-	-
447	Sale for resale	12,678	21,076	26,062	32,955
	Total electric service revenues	$ 669,354	$ 696,139	$ 765,171	$ 831,510
Other Electric Revenue					
450	Forfeited discounts	$ 3,229	$ 3,229	$ 3,583	$ 3,943
451	Miscellaneouse service revenues	1,903	1,903	2,246	1,596
454	Rent from electric property	19,477	19,477	19,477	19,679
456	Other electric revenues	47,656	47,885	45,615	31,612
	Total other electric revenues	$ 72,265	$ 72,494	$ 70,921	$ 56,829
	Total operating revenues	$ 741,619	$ 768,633	$ 836,092	$ 888,339
Operating Expenses					
401-2	Operation and maintenance expense				
	Power production expenses	$ 275,734	$ 320,216	$ 378,228	$ 408,304
	Transmission expenses	21,154	21,730	23,071	14,314
	Regional market expenses	54	50	43	60
	Distribution expenses	37,980	33,837	48,826	48,831
	Customer accounts expense	23,271	25,286	24,842	24,195
	Customer service & information expense	40,696	44,185	39,990	51,349
	Sales expenses	25	24	15	13
	Administrative & general expenses	41,116	37,806	6,525	57,158
	Subtotal	$ 440,030	$ 483,134	$ 521,541	$ 604,223
403	Depreciation expense	$ 59,721	$ 56,892	$ 55,187	$ 69,205
404-5	Amortization and depletion of utility plant	4,710	2,681	3,006	3,130
406	Amortization and utility plant acq. adjustment		-	-	-
407	Amortization of property losses		-	-	-
407.3	Regulatory debits	22,920	24,410	35,722	212,875
407.4	Regulatory credits	15,407	(11,449)	(23,530)	(194,776)
408.1	Taxes other than income taxes	45,795	46,882	50,525	54,381
411.1	Accretion expense	49	62	58	54
411.8	Gains from disposition allowance			-	-
	Total operating expenses before federal and state income taxes	$ 588,632	$ 602,611	$ 642,508	$ 749,091
	Net operating income before income taxes	$ 152,987	$ 166,021	$ 193,584	$ 139,247
Income taxes					
409.1	Income taxes-federal	$ 39,423	$ 25,303	$ 28,956	$ (43,523)
409.1	Income taxes-state	-	-	5,701	(7,869)
410.1	Provision for deferred income taxes	49,263	67,085	131,537	259,974
411.1	Income taxes deferred in prior years-cr.	(42,966)	(39,764)	(190,653)	(166,189)
411.4	Investment tax credit adjustments-net	(364)	(364)	(397)	(421)
	Total income taxes	$ 45,356	$ 52,260	$ (24,855)	$ 41,972
	Net operating income	$ 107,631	$ 113,762	$ 218,439	$ 97,275
Other income					
415-16	Revenues from merchandising, jobbing and contract work	$ 2,808	$ 3,681	$ 1,995	$ 2,128
417	Revenues from non-utility operations			-	-
417.1	Expenses from non-utility operations			-	-
418	Nonoperating rental income	(17)	(17)	333	(17)
418.1	Equity in earnings of subsidiary companies			-	-
				-	-
419	Interest and dividend income	1,647	98	666	(9)
419.1	Allowance for funds used during construction	1,343	1,852	-	8
				-	-
421	Miscellaneous non-operating income	1,740	1,740	2,546	1,248
421.1	Gain on disposition of property			-	-

Metropolitan Edison Company
Comparative Income Statements

FERC Account		April 30, 2016	March 31, 2015	2014	2013
			(In thousands)		
	Total other income	$ 7,522	$ 7,354	$ 5,540	$ 3,358
	Gross income	$ 115,153	$ 121,115	$ 223,980	$ 100,633
Other Income Deductions					
421.2	Loss on disposition of property			$ -	$ -
425	Miscellaneous amortization			-	-
426	Other income deductions	146	146	189,014	353
	Total other income deductions	$ 146	$ 146	$ 189,014	$ 353
Taxes Applicable to Other Income and Deductions					
408.2	Taxes other than income taxes			$ -	$ -
409.2	Income taxes - federal			2,249	1,078
409.2	Income taxes - state			713	342
410.2	Provision for deferred income taxes			6	2
411.2	Provision for deferred income taxes-cr.			(26)	(18)
	Total taxes on other income and deductions	$ -	$ -	$ 2,942	$ 1,404
Interest Charges					
427	Interest on long term debt	$ 51,862	$ 40,717	$ 45,258	$ 43,803
428	Amortization of debt discount and expense	911	700	821	763
				-	-
428.1	Amortization of loss on reacquired debt	247	544	2,881	1,643
				-	-
429	Amortization of premium on debt credit			74	(294)
429.1	Amortization of gain on reacquired debt	(144)	(144)	(284)	-
430	Interest on debt to associated companies	8	1,036	2,731	3,772
431	Other interest expense	3,859	4,152	3,529	2,946
432	Allowance for borrowed funds used during construction - credit	(892)	(1,229)	(647)	(266)
				-	-
	Total interest charges	$ 55,852	$ 45,776	$ 54,364	$ 52,367
	Income before extraordinary items	$ 59,155	$ 75,194	$ (22,340)	$ 46,509
Extraordinary Items & Related Taxes					
434	Extraordinary income			$ -	$ -
435	Extraordinary deductions			-	-
409.3	Income taxes - Federal & other			-	-
	Extraordinary items after taxes	$ -	$ -	$ -	$ -
	Net income	$ 59,155	$ 75,194	$ (22,340)	$ 46,509
Power Production Expenses					
Steam Power Generation					
Operation					
501	Fuel			$ -	$ (3)
514	Maintenance of miscellaneous steam plant	3,357	1,212	339	146
	Total operation	$ 3,357	$ 1,212	$ 339	$ 143
	Total steam power generation	$ 3,357	$ 1,212	$ 339	$ 143
Nuclear Power Generation					
Operation					
518	Fuel			$ -	$ -
	Miscellaneous nuclear power expenses			-	-
	Total operation	$ -	$ -	$ -	$ -
	Total nuclear power generation	$ -	$ -	$ -	$ -
Other Power Generation					
Operation					
549	Miscellaneous other power generation expenses			-	-
	Total operation	$ -	$ -	$ -	$ -

Metropolitan Edison Company
Comparative Income Statements

FERC Account		April 30, 2016	March 31, 2015	2014	2013
			(In thousands)		
	Total other power generation	$ -	$ -	$ -	$ -
Other Power Supply Expenses					
555	Purchased Power	$ 278,084	$ 326,146	$ 379,195	$ 457,126
556	System control and load dispatching			-	-
557	Other expenses	(5,707)	(7,143)	(1,307)	(48,965)
	Total other power supply expenses	$ 272,377	$ 319,004	$ 377,888	$ 408,161
	Total power production expenses	$ 275,734	$ 320,216	$ 378,228	$ 408,304
Transmission Expenses					
Operation					
560	Operation supervision and engineering	$ 58	$ 53	$ 97	$ 21
561	Load dispatching	1,208	1,309	907	1,867
562	Station expenses	174	-	45	67
563	Overhead lines expense	33	33	16	18
564	Underground lines expenses	-	-	-	-
565	Transmission of electricity by others	11,776	12,626	12,151	2,278
566	Miscellaneous transmission expenses	1,198	1,227	466	1,228
567	Rents	472	472	453	270
	Total operation	$ 14,920	$ 15,721	$ 14,134	$ 5,748
Maintenance					
568	Maintenance supervision and engineering	$ 920	$ 880	$ 772	$ 423
569	Maintenance of structures	224	215	293	366
570	Maintenance of station equipment	2,650	2,538	1,867	1,474
571	Maintenance of overhead lines	2,347	2,284	5,922	6,248
572	Maintenance of underground lines	-	-	0	-
573	Maintenance of miscellaneous transmission plant	93	93	81 -	55 -
	Total maintenance	$ 6,234	$ 6,009	$ 8,936	$ 8,566
	Total transmission expenses	$ 21,154	$ 21,730	$ 23,071	$ 14,314
Regional Market Expenses					
Operation					
575	Operation-regional market expense	$ 54	$ 50	$ 43	$ 60
	Total operation	$ 54	$ 50	$ 43	$ 60
Maintenance					
576	Maintenance-regional market expense			$ -	$ -
	Total maintenance	$ -	$ -	$ -	$ -
	Total regional market expenses	$ 54	$ 50	$ 43	$ 60
Distribution Expenses					
Operation					
580	Operation supervision and engineering	$ 97	$ 88	$ 59	$ 354
581	Load dispatching	339	329	259	353
582	Station expenses	615	603	943	749
583	Overhead lines expense	37	37	299	31
584	Underground lines expenses	576	576	141	550
585	Street lighting and signal system expenses	-	-	(1)	(2)
586	Meter expenses	771	738	597	488
587	Customer installation expenses	-	-	-	-
588	Miiscellaneous expenses	4,949	5,077	5,213	4,948
589	Rents	541	541	555	546
	Total operation	$ 7,926	$ 7,988	$ 8,064	$ 8,016
Maintenance					
590	Maintenance supervision and engineering	$ 390	$ 353	$ 392	$ 452
591	Maintenance of structures	16	16	9	11
592	Maintenance of station equipment	4,043	3,491	2,667	2,849
593	Maintenance of overhead lines	20,233	16,670	30,983	31,106
594	Maintenance of underground lines	2,048	2,088	2,381	1,736
595	Maintenance of line transformers			-	2
596	Maintenance of street lighting and signal systems	250	247	657 -	667 -
597	Maintenance of meters	1,645	1,614	1,996	2,146

Metropolitan Edison Company
Comparative Income Statements

FERC Account		April 30, 2016	March 31, 2015	2014	2013
			(In thousands)		
598	Maintenance of miscellaneous distribution plant	1,428	1,371	1,677	1,846
				-	-
	Total maintenance	$ 30,054	$ 25,848	$ 40,762	$ 40,815
	Total distribution expenses	$ 37,980	$ 33,837	$ 48,826	$ 48,831
Customer Account Expenses					
Operation					
901	Supervision		$ -	$ 6	$ 5
902	Meter reading expenses	5,026	5,184	4,057	4,570
903	Customer records and collection expenses	5,858	5,998	6,199	6,645
904	Uncollectible accounts	12,136	13,864	14,346	12,690
905	Miscellaneous customer accounts expense	251	241	235	285
	Total customer accounts expense	$ 23,271	$ 25,286	$ 24,842	$ 24,195
Customer Service and Informational Expenses					
Operation					
907	Supervision	$ 304	$ 293	$ 206	$ 194
908	Customer assistance expenses	34,566	38,163	34,403	46,243
909	Informational and instructional expenses	130	58	1	0
910	Miscellaneous customer service and informational expenses	5,696	5,670	5,380	4,911
				-	-
	Total customer service and informational expense	$ 40,696	$ 44,185	$ 39,990	$ 51,349
Sales Expenses					
Operation					
911	Supervision			$ -	$ -
912	Demonstrating and selling expenses			-	-
913	Advertising expenses	25	24	15	13
916	Miscellaneouse sales expenses			0	-
	Total sales expenses	$ 25	$ 24	$ 15	$ 13
Administrative and general expenses					
Operation					
920	Administrative and general salaries	$ (524)	$ (363)	$ 2,858	$ 373
921	Office supplies and expense	3,155	2,908	2,599	2,268
922	Administrative expenses transferred-credit	(3,082)	(3,163)	(5,116)	(7,730)
923	Outside services employed	35,388	38,839	32,607	33,727
924	Property insurance	242	227	165	149
925	Injuries and damages	930	854	950	3,974
926	Employee pensions and benefiits	(745)	(7,111)	(33,506)	17,321
927	Franchise requirements		-	-	-
928	Regulatory commission expenses	2,632	2,469	2,460	2,761
929	Duplicate charges - credit			-	-
930.1	General advertising expenses	10	10	83	1,010
930.2	Miscellaneous general expenses	698	748	778	696
931	Rents	1,612	1,588	1,305	657
	Total administrative and general expenses	$ 40,316	$ 37,005	$ 5,183	$ 55,206
Maintenance					
935	Maintenance and general plant	801	801	1,342	1,952
	Total maintenance	$ 801	$ 801	$ 1,342	$ 1,952
	Total administrative and general expenses	$ 41,116	$ 37,806	$ 6,525	$ 57,158
	Total electric operation and maintenance expenses	$ 440,030	$ 483,134	$ 521,540	$ 604,223

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT VI-C:

"Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

C. Plant in service."

RESPONSE:

See Met-Ed Exhibit RAD-56 Attachment A.

METROPOLITAN EDISON COMPANY
Plant in Service

FERC Account		4/30/2016	3/31/2015	3/31/2014	3/31/2013
		(In thousands)			
	Intangible				
301	Organization	$ 124	$ 124	$ 124	$ 124
302	Franchises and Consents	165	165	165	165
303	Miscellaneous Intangible Plant	57,878	41,603	38,675	38,320
303	Smart Meter Software	13,104	2,160	-	-
	Total Intangible Plant	$ 71,270	$ 44,051	$ 38,964	$ 38,608
	Nuclear Production				
326	Asset Retirement Costs	$ 95,321	$ 95,321	$ 95,321	$ 95,321
	Total Nuclear Production	$ 95,321	$ 95,321	$ 95,321	$ 95,321
	Transmission Plant				
350	Fee Land - Trans. Subs.	$ 1,384	$ 1,384	$ 1,384	$ 1,384
350	Easements - Trans. Subs.	173	173	173	410
350	Fee Land - Trans. Lines	2,045	2,045	2,045	2,045
350	Easements - Trans. Lines	26,760	26,760	26,760	26,760
352	Structures, Improvements	6,475	6,475	6,475	5,744
352	Clearing, Grading Of Land	305	305	305	1,704
353	Station Equipment	210,580	194,600	183,423	166,316
354	Towers And Fixtures	41,083	41,083	41,083	41,962
355	Poles And Fixtures	46,550	46,550	46,550	43,899
356	Overhd Conductr, Devices	99,183	94,208	69,633	64,882
356	Clearing, Grading of Land	17,683	17,683	17,683	13,185
358	Undergrnd Conductr,Devices	1,191	1,191	1,191	1,024
359	Roads And Trails	747	747	747	747
359	ARC Transmission	5	5	5	5
	Total Transmission Plant	$ 454,163	$ 433,209	$ 397,456	$ 370,067
	Distribution Plant				
360	Fee Land - Dist. Subs.	$ 2,777	$ 2,777	$ 2,777	$ 2,777
360	Easements - Dist. Subs.	611	611	611	375
360	Fee Land - Dist. Lines	428	428	428	303
360	Easements - Dist. Lines	28,321	28,321	28,321	28,321
361	Structures, Improvements	12,746	12,746	12,746	12,676
361	Clearing, Grading of Land	366	366	366	130
362	Station Equipment	216,798	212,973	203,494	198,607
364	Poles, Towers And Fixtures	354,211	354,211	354,211	382,641
365	Overhd Conductr, Devices	368,193	368,193	368,193	325,681
365	Clearing, Grading of Land	131,740	131,740	131,740	122,276
366	Underground Conduit	30,297	30,297	30,297	30,229
367	Undergrnd Conductr,Devices	203,213	203,213	203,213	190,569
368	Line Transformers	502,265	450,298	392,738	388,640
369	Services	169,525	169,525	169,525	166,963
370	Meters	66,795	66,795	66,795	64,399
370	Smart Meters Res	11,620	2,241	1,554	-
371	Inst. On Cust. Prem.	4,520	4,520	4,520	4,414
373	Street Light - Oh, Ug Lines	12,289	12,289	12,289	11,516
374	ARC Distribution	37	37	37	37

METROPOLITAN EDISON COMPANY
Plant in Service

FERC Account		4/30/2016	3/31/2015	3/31/2014	3/31/2013
	Total Distribution Plant	$ 2,116,751	$ 2,051,579	$ 1,983,854	$ 1,930,555
	General Plant				
389	Fee Land	$ 2,673	$ 2,673	$ 2,673	$ 1,568
389	Easements	18	18	18	18
390	Structures, Improvements	87,469	87,468	85,738	85,320
390	Clearing, Grading of Land	12,466	12,466	12,466	12,466
390	Struct Imprv, Leasehold Imp	17	17	17	17
391	Office Furn., Mech. Equip.	16,631	16,631	16,631	17,100
391	Office Machines	5,921	5,921	5,921	5,921
391	Data Processing Equipment	4,627	4,627	4,627	2,553
391	Data Proc Smart Meters	9,299	6,356	903	-
391	Information System	(12)	(12)	(12)	0
392	Transportation Equipment	5,185	4,229	1,067	1,219
393	Stores Equipment	1,411	1,411	1,411	1,429
394	Tools, Shop, Garage Equip.	11,712	11,712	11,712	10,253
395	Laboratory Equipment	3,048	3,048	3,048	3,130
396	Power Operated Equipment	752	752	752	643
397	Communication Equipment	34,023	34,023	34,023	35,659
398	Misc. Equipment	2,587	2,587	2,587	2,671
399	ARC General Plant	106	106	106	106
	Total General Plant	$ 197,931	$ 194,032	$ 183,686	$ 180,073
	Total Plant in Service	$ 2,935,437	$ 2,818,193	$ 2,699,281	$ 2,614,625

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT VI-D:

"Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

D. Accumulated depreciation."

RESPONSE:

See Met-Ed Exhibit RAD-57 Attachment A.

Metropolitan Edison Company
Reserve for Depreciation

FERC Account	April 30,2016	March 31, 2015	March 31, 2014	March 31, 2013
		(In thousands)		
303 2002 Software	$ 1,950	$ 1,950	$ 1,950	$ 1,950
303 2003 Software	859	859	859	859
303 2004 Software	3,919	3,919	3,919	3,919
303 2005 Software	794	794	794	794
303 2006 Software	1,212	1,212	1,212	1,175
303 2007 Software	6,544	6,544	6,253	5,090
303 2008 Software	800	830	951	992
303 2009 Software	2,354	1,949	1,575	1,200
303 2010 Software	1,121	1,003	895	787
303 2011 Software	3,487	2,729	2,029	1,295
303 2012 Software	315	202	98	5
303 2013 Software	785	475	189	2
303 Proj Enterprise	622	622	622	622
303 Software	3,084	1,632	1,009	658
303 Software Evolution	8,048	8,048	8,048	8,048
303 Smart Meters	1,463	106	-	-
Intangibles Total	$ 37,357	$ 32,874	$ 30,403	$ 27,396
350.12 Tran Sub Easement	$ 110	$ 107	$ 105	$ 101
350.21 Tran Line Land	8	8	8	8
350.22 Tran Line Easement	12,274	11,839	11,438	11,036
352 Struct PCA Dist	70	68	66	64
352 Structures/improve	2,912	2,780	2,658	2,601
353 Station Eq PCA Dist	2,365	2,216	2,079	1,957
353 Station equipment	57,609	55,830	54,045	52,321
354 Towers & Fixtures	27,717	27,190	26,703	26,258
354 Towers PCA Dist	34	34	33	33
355 Poles & Fixtures	18,963	18,252	17,595	17,454
355 Poles PCA Dist	403	394	386	377
356 OH Cond PCA Dist	303	296	289	282
356 Overhead Conductor	28,367	27,579	29,184	28,877
356.10 Clearing & R/W	3,185	3,087	2,997	3,013
356.10 R/W PCA Dist	929	770	624	309
356.20 Veg Clrng-FERC exp	-	-	-	-
358 UG Cond PCA Dist	-	-	-	-
358 Undergound Conductor	130	98	69	41
359 Roads & Trails	543	525	509	492
359 Roads PCA Dist	8	8	8	7
TXM SUB ARC	3	3	3	3
Transmission total	$ 155,933	$ 151,084	$ 148,799	$ 145,234

FERC Account	April 30,2016	March 31, 2015	March 31, 2014	March 31, 2013
		(In thousands)		
360.12 Dist Sub Easement	$ 192	$ 182	$ 173	$ 165
360.22 Dist Line Easement	14,836	14,384	13,967	13,550
361 Structure/Improve	6,566	6,226	5,912	5,602
361.20 Grading Clearing	33	24	15	9
362 Station equipment	76,801	73,640	71,464	69,591
364 Poles towers fix	114,047	108,880	104,111	101,435
365 Overhead conductor	87,557	80,902	74,758	74,288
365.10 Clearing & R/W	21,120	18,941	16,929	15,025
365.10 Veg Clrng-FERC exp	-	-	-	-
366 Underground conduit	11,950	11,377	10,848	10,327
367 Undergrd conductor	78,292	72,015	66,221	62,132
368 Line Transformers	132,974	127,714	124,985	120,583
369 Services OH	21,492	19,718	18,079	16,527
369 Unground Services	51,141	48,736	46,516	44,296
370 Meters	16,632	14,728	12,085	10,867
370 Smart Meters Res	499	159	50	-
371 Inst on cust prem	2,112	1,978	1,855	1,753
371 Meter Socket dvc 125	-	-	-	-
371 Meter Socket dvc 126	-	-	-	-
371 Meter Socket dvc 127	-	-	-	-
371 Meter Socket dvc 1PH	329	315	301	288
371 Meter Socket dvc 3PH	-	-	-	-
371 Surge Suppression 2	241	241	241	241
371 Surge Suppression 4	36	36	36	36
373 Street Lighting	3,508	3,160	2,839	3,113
DIST SUB ARC	23	22	21	21
Distribution Total	$ 640,381	$ 603,378	$ 571,406	$ 549,849
389.20 Land Rights	$ 16	$ 16	$ 15	$ 15
390.10 Easton Serv Center	4,661	4,322	4,009	3,766
390.10 Lebanon Serv Ctr	3,510	3,306	3,119	3,035
390.10 South Bldg Reading	27,491	26,265	25,342	24,250
390.10 Structures	8,683	8,239	7,830	7,427
390.10 York Serv Center	4,420	4,193	3,983	3,774
390.20 Corp Hqtrs Reading	1,903	1,805	1,714	1,624
390.20 Easton Ser Ctr	1,117	990	873	756
390.20 Land/Yard Improvem	3,191	3,007	2,837	2,667
390.20 Lebanon Ser Ctr	842	817	794	770
390.20 York Ser Ctr	1,240	1,190	1,143	1,096
390.30 Transfered LH	6	5	4	3
391.10 Office Furniture	16,193	15,389	14,646	14,419
391.15 Office Machines	5,921	5,921	5,921	5,921
391.20 Personal Computers	3,883	3,029	2,240	1,965
391.25 Data Proc Smart Me	1,565	222	86	-

FERC Account	April 30,2016	March 31, 2015	March 31, 2014	March 31, 2013
		(In thousands)		
391.25 Information Sys	(12)	(7)	(3)	-
392 Transportation equip	141	109	80	52
392.40 Pole Trailers	514	486	461	435
392.50 Van Trailers	81	80	79	78
393 Stores Equipment	1,411	1,411	1,404	1,391
394 Tools shop garage	7,757	7,199	6,684	6,492
395 Laboratory equip	3,048	3,048	3,048	3,130
396 Power operated equip	622	617	613	609
397 Communication Equipt	25,656	24,596	23,914	25,011
398 Miscellaneous equipt	2,587	2,567	2,505	2,539
EASTON BLDG ARC	4	4	4	4
GEN BLDG ARC	32	31	30	28
LEBANON BLDG ARC	4	4	4	4
READING SOUTH BLDG ARC	9	8	8	8
YORK BLDG ARC	3	3	3	3
General Total	$ 126,499	$ 118,872	$ 113,390	$ 111,272
TMI#2 ARC Total	$ 95,321	$ 95,321	$ 95,321	$ 95,321
Total	$ 1,055,491	$ 1,001,529	$ 959,319	$ 929,072

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT I-A-4:

> "Whenever a major generating plant is placed in operating service or removed from operating service the utility shall separately indicate the effect of the plant addition or removal from service upon rate base, revenue, expense, tax, income and revenue requirement as it affects the test year."

RESPONSE:

This base rate case filing requirement is not applicable to the Company's filing.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT I-B-2:

"Provide a description of the property of the utility and an explanation of the system's operation, and supply the following, using available projections if actual data is unavailable

a. A schedule of generating capability showing for the test year, and for the two consecutive 12-month periods prior to the test year, net dependable capacity in KW by unit, plant capacity factor by unit, and total fuel consumption by type and cost for each unit, if available, or for each station, and operation and maintenance expenses by station.

b. A schedule showing for the test year and for the 12-month period immediately prior to the test year the scheduled and unscheduled outages—in excess of 48 hours—for each station, the equipment or unit involved, the date the outage occurred, duration of the outage, maintenance expenses incurred for each outage, if available, and amounts reimbursable from suppliers or insurance companies.

c. A schedule for each unit retired during the test year or subsequent to the end of the test year, which shows the unit's KW capacity, hours of operation during the test year, net output generated, cents/KWH of maintenance and fuel expenses, and date of retirement

d. A schedule showing latest projections of capacity additions and retirements—costs and KW—and reserve capacity at the time of peak for at least 10 years beyond the test year, including the inservice dates—actual or expected—and AFDC cutoff dates—if different from inservice dates—for all new generating units coming on line during or subsequent to the test year, if claimed."

RESPONSE:

This base rate case filing requirement is not applicable to the Company's filing.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-B-5:

"Describe long-term debt reacquisition by issue by Company and Parent as follows:

a. Reacquisition by issue by year.
b. Total gain or loss on reacquisitions by issue by year.
c. Accounting for gain or loss for income tax and book purposes.
d. Proposed treatment of gain or loss on such reacquisition for ratemaking purposes."

RESPONSE:

a. Please see Met-Ed Exhibit RAD-60 Attachment A.
b. Please see Met-Ed Exhibit RAD-60 Attachment A.

c. *Tax Accounting:*

Gains attributable to the reacquisition of long-term debt are recognized on the same basis recorded for book purposes.

Losses on the reacquisition of long-term debt are deducted currently for income tax purposes in the year of reacquisition, which creates book-tax temporary differences. As a result of these temporary differences, the Company records deferred income taxes by means of debits to Account 410.1, Provision for Deferred Income Taxes, Utility Operating Income, with corresponding credits to Account 283, Accumulated Deferred Income Taxes – Other. Amounts recorded in Account 283 are reversed over the remaining life of the respective security issue consistent with book amortization of the loss by means of credits to Account 411.1, Provision for Deferred Income Taxes – Credit, Utility Operating Income.

Book Accounting:

In accordance with General Instruction 17 of the Uniform System on Accounts, gains on reacquired debt are placed in Account No. 257 "Unamortized Gain on Reacquired Debt". The gains are then amortized to Account No. 429.1 "Amortization of Gain on Reacquired Debt-Credit" over the remaining lives of the respective issues (old original debt).

In accordance with General Instruction 17 of the Uniform System of Accounts, losses on reacquired debt are placed in Account No. 189 "Unamortized Loss on Reacquired Debt". The losses are then amortized to Account No 428.1 Amortization of Loss on Reacquired Debt" over the remaining lives of the respective issues (old original debt).

d. The amortization of gain or loss on long term debt reacquisition for ratemaking purposes is addressed on RAD-2, page 12.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-B-5

Line No.	Description	Amount	Total Gain (Loss) On Reacquired Debt	ACTUAL Unamortized Gain (Loss) as of March 31, 2013	ACTUAL Unamortized Gain (Loss) as of March 31, 2014	PROJECTED Unamortized Gain (Loss) as of March 31, 2015	PROJECTED Unamortized Gain (Loss) as of April 30, 2016
	2003						
1	7.65% First Mortgage Bond series due 5/31/2023	30,000,000	(1,103,306.63)	(560,847.63)	(505,682.29)	(450,516.95)	(390,754.50)
2	6.97% First Mortgage Bond series due 9/30/2023	30,000,000	(2,967,551.70)	(1,557,964.53)	(1,409,586.96)	(1,261,209.39)	(1,100,467.02)
	2004						
3	7.35% Capital Preferred Trust series due 4/1/2014	100,000,000	(5,960,820.11)	(715,557.34)	(1,982.15)	-	-
4	7.35% Preferred Trust series due 9/1/2014	100,000,000	(7,172,482.87)	(997,154.21)	(294,658.09)	-	-
5	6.36% Medium Term Note due 4/1/2014	17,000,000	220,776.78	22,107.44	61.24	-	-
6	6.40% Medium Term Note Due 4/1/2014	33,000,000	447,541.86	44,816.05	124.14	-	-
	2005						
7	6.10% Medium Term Note Due 7/15/2021	28,500,000	1,652,569.08	880,071.32	773,932.06	667,792.80	552,808.61
	2008						
8	Var% SR 2005A BCIDA due 7/15/21	28,500,000	(306,749.60)	(193,100.44)	(169,811.94)	(146,523.44)	(121,294.24)
	2011						
9	5.95% FMB due 5/15/2027	13,690,000	601,610.32	529,645.97	492,148.91	454,651.85	414,030.04
	TOTAL		(2,547,983.37)	(1,115,455.08)	(735,805.13)	(645,677.11)	

METROPOLITAN EDISON COMPANY

"Filing of information and materials – Whenever a public utility proposes a change in rates under section 1308 (relating to voluntary changes in rates), the public utility shall file with the commission a listing of each type of advertising prepared, distributed or presented by the pubic utility or to be prepared, distributed or presented during the test year utilized by the public utility in discharging its burden of proof, and a listing of each type of advertising prepared, distributed or presented by the utility during the year immediately preceding the test year, as well as an accounting of the expenditures by the public utility for such advertising, to the extent such advertising is proposed to be included as operating expense for ratemaking purposes. The filing requirements imposed by this subsection shall not be construed to limit the right of any party to discovery under this or any other provision of law."

Summary of Advertising Expenses

Section 1316 of Title 66, Pa. Consolidated Statutes, addresses recovery of advertising expenses. In accordance with the filing requirements specified in § 1316(c), following is a listing of the types of advertising comprising the total advertising expenses for the fully future test year and the immediately preceding 2 years.

Metropolitan Edison Company
Summary of Advertising Expenses
(000's)

Line No.	Description	12 months ending April 30. 2016 Budgeted	March 31. 2015 Budgeted	March 31. 2014 Actual
			(In thousands)	
1	Customer Service Informational & Instructional Advertising	$ 130	$ 58	$ 1
2	Sales Advertising	25	26	15
3	A&G Advertising - General	10	10	5
4	Public relations	-	-	75
5	Miscellaneous	-	-	2
6	Total advertising	$ 165	$ 94	$ 98

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT TITLE 52, SECTION 69.36

"The Pennsylvania Public Utility Commission intends to examine specific factors in rate proceedings of electric and gas utilities regarding the action or failure to act to encourage development of cost effective energy supply alternatives. Specifically, the Commission will review utilities' efforts to meet the criteria in this section when determining just and reasonable rates in future rate proceedings and may consider those efforts in other proceedings instituted by the Commission

(1) *Information.* At least twice annually utilities should provide customers with information on specific means of utilizing their energy services more effectively and efficiently. Topic areas should include insulation, lighting efficiencies, appliance efficiencies, conservation practices, load management techniques or other relevant information that informs the customer of the efficient use of energy.

(2) *Energy surveys.* Class A utilities should offer onsite energy surveys to the residential, commercial and industrial classes on an ongoing basis. Surveys should be conducted by trained personnel and the results of the survey, upon written request of the customer, be delivered in writing with a clear explanation of the resulting components.

(3) *Cogeneration and small power production.* Electric utilities for which a need for capacity is projected should establish effective programs to explore and encourage the development of additional cogeneration and small power production facilities within their respective service territories.

(4) *Least cost planning.* Gas and electric utilities should actively pursue a least-cost strategy by acquiring and developing the resources necessary to effectively meet their customers' future energy needs, consistent with established availability and reliability criteria. Utilities should make a reasonable effort to promote the utilization of practical and economical energy conservation and demand management through cost effective programs.

(5) *Evaluation.* Class A utilities should demonstrate progressive work regarding development of a reliable customer data base, including, but not limited to:

(i) End-use applications for each class of customer in terms of energy and demand.
(ii) Customer behavior with regard to the decision-making process.

(iii) The impact of program decisions or strategies and how they effect the overall planning process.

6) *Natural gas co-firing.* Electric utilities should explore the potential for increasing capacity and output at coal-fired generating stations through gas co-firing"

RESPONSE:

1) Customer service representatives discuss these "Energy Efficient" topics with customers by referring to the "Energy Decision Maker Brochure" which provides energy saving information for most household electrical appliances and equipment. Representatives offer to mail a copy of the brochure to customers and if appropriate, discuss the Time of Day Rate. The Company's interactive voice response unit also provides this brochure through the "Literature Request" option. These "Energy Efficient" topics are also fully described and available 24/7 on the FirstEnergy website under the "Customer Care" section at the following location:

http://www.firstenergycorp.com/customercare/engine?s=com.firstenergycorp.customercare.www.Home&p=%2F

In addition, on October 15, 2008, Governor Rendell signed HB 2200 into law as Act 129 of 2008[1], with an effective date of November 14, 2008. The Act imposes requirements on electric distribution companies (EDCs), with the overall goal of reducing energy consumption and demand. Act 129 directed all EDCs with at least 100,000 customers to develop and file an energy efficiency and conservation plan. The Company has filed and obtained approval for an Energy Efficiency and Conservation (EE&C) Plan that complies with Commission Orders[2]. The EE&C plan contains numerous programs that are designed to achieve energy efficiency and conservation across all customer segments. Essential to the success of these programs is a concurrent marketing and educational campaign. As part of this, the Company has an outreach effort that: (i) builds awareness and interest in the programs; (ii) communicates ways that customers may participate; and (iii) explains expected benefits and reasons for participating. Information about the EE&C programs available to customers is provided using a number of marketing channels such as via bill inserts, advertisements as well as through the Company's website at:

http://www.firstenergycorp.com/save_energy/save_energy_pennsylvania.html

2) Residential home energy surveys are conducted at no additional cost for income-eligible customers as part of the Low Income Usage Reduction Program known as

[1] 66 Pa.C.S. §§ 2806.1 and 2806.2
[2] Docket Nos. M-2009-2092222 and M-2012-2334387

WARM (Chapter 58). Met-Ed income eligible customers who have lived at their residence at least 6 months are eligible for WARM. The WARM program home energy survey addresses ways to save electricity for customers who have electric heat, electric water hear, air conditioning or base load use. These surveys are conducted by Building Performance Institute Certified contractors hired by Met-Ed. The program is open to both homeowners and renters with landlord agreement. As part of the home energy survey, contractors may perform pressure diagnostic testing using a blower door and manometers to determine where there is air leakage in the home. They also test ducts, conduct combustion safety testing and monitor electricity use of various appliances such as refrigerators and freezers for possible replacement. A personalized partnership agreement and energy-saving strategy for the home and occupants are provided as part of the program.

In addition, residential customers may also participate in the Company's Act 129 energy audit program. Under this program, home energy audits are conducted by trained local contractors hired by the Company's Conservation Service Provider for a fee of $350. Customers who participate in this program receive a comprehensive home energy audit which is designed to provide information on how to reduce their energy usage and increase their home's comfort and energy efficiency. Participating customer's qualify for up to $250 in rebates towards the cost of a comprehensive residential energy audit and qualified retrofits.

Residential customers can also complete the Company's Home Energy Analyzer online tool at http://www.firstenergycorp.com/content/customer/save_energy/save_energy_pennsylvania/for_your_home/pa_home_energy_analyzer.html to save energy and money. The tool enables customers to gain a better understanding of their household energy use and identify ways to improve their efficiency.

The Company also promotes detailed energy audits for commercial and industrial customers under the Company's Act 129 programs. Customers who implement recommended building and/or system improvements are eligible for incentives towards the cost of the third party audit and qualifying audit recommended improvements.

Similar to residential customers, business customers can complete the Business Energy Analyzers online tool at https://www.firstenergycorp.com/content/customer/save_energy/save_energy_pennsylvania/for_your_business/pennsylvania_businessenergyanalyzer.html. The tool will enable business customers to gain a better understanding of their energy use and identify ways to improve their efficiency.

3) Met-Ed's Rider H- Renewable Energy Development Rider is currently available to residential and non-residential customers. This rider encourages the installation and

operation of qualifying renewable energy generation projects to operate in parallel with the Company's electrical system.

4) All capacity requirements are secured through Commission approved default service plans.

5) See the direct testimony of Kevin M. Siedt, Met-Ed Statement No. 4.

6) This filing requirement is not applicable to the Company's filing.

METROPOLITAN EDISON COMPANY
Distribution Storm Costs
2009 – 4/30/2016

Line No.	Year	Storm Costs
1	2009	$ 7,075,372
2	2010	12,760,136
3	2011	34,827,259
4	2012	32,594,558
5	2013	1,208,183
6	12 mos. Ended March 31, 2014	14,921,313
7	12 mos. Ended March 31, 2015	6,564,065
8	12 mos. Ended April 30, 2016	6,625,214

Met-Ed/Penelec/Penn Power/West Penn
Costs of Compliance with Docket No. L-2014-2409383

This exhibit contains the expenditures and operations and maintenance ("O&M") costs associated with implementation of the Commission's three day switching requirement introduced at Docket No. L-2014-2409383 entered April 3, 2014. The exhibit contain incremental O&M expenses plus a five year amortization of additional capital expenditures to implement 3-5 day switches.

Phase I is an eight month project commencing May 1, 2014 with anticipated implementation by the end of December 2014. Phase I will enable the Companies to allow for one customer switch to be accomplished per individual customer account that has no other pending orders. The first phase of the project is a capital effort requiring the labor of 12 full time equivalent ("FTE"), working during Phase I development. Phase I development costs are expected to be $1,382,000.

Phase II is the on-going effort to modify the existing systems in order to implement multiple customer switches per month and ensure customers on payment programs can be accommodated. Phase II development would commence after Phase I is completed with anticipated implementation by the end of June 2015. The Phase II development costs are expected to be $850,000.

In addition, the Companies would need to add to existing staff 6 FTE's in Customer Service and Information Technology plus the cost of mailing letters to customers of multiple switches of $455,000 plus $227,500 for labor related overheads for a total of $682,500 on ongoing O&M costs.

Line No.	Description	Amount
1.	Phase I Capital Costs	$1,382,000
2.	Phase II Capital Costs	850,000
3.	Total	$2,232,000
4.	Five Year Recovery	$ 446,400
5.	On-going O&M expenses	682,500
6.	Total to be recovered annually	$1,128,900

Met-Ed/Penelec/Penn Power/West Penn
Costs of Compliance with Docket No. L-2014-2409383

Allocation to Pennsylvania operating companies based on number of customers:

		Amount ($000)
7.	Met-Ed	$ 311
8.	Penelec	326
9.	Penn Power	90
10.	West Penn	402
11.	Total	$ 1,128

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2014-2428745

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. R-2014-242743

PENNSYLVANIA POWER COMPANY
DOCKET NO. R-2014-242744

WEST PENN POWER COMPANY
DOCKET NO. R-2014-2428742

Direct Testimony
of
Richard A. D'Angelo

List of Topics Addressed

Accounting and Financial Data
Budgets
Ratemaking Adjustments to Budgeted Test Year Data
Regulatory Treatment of Storm Damage Costs
Accelerated Customer Switching Costs
Other Filing Requirements

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DIRECT TESTIMONY
OF
RICHARD A. D'ANGELO

I. INTRODUCTION AND PURPOSE

Q. Please state your name and business address.

A. My name is Richard A. D'Angelo. My business address is 2800 Pottsville Pike Reading, Pennsylvania 19605.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company as Manager – Rates and Regulatory Affairs – Pennsylvania.

Q. Please describe your responsibilities as Manager – Rates and Regulatory Affairs – Pennsylvania.

A. Generally, the Rates and Regulatory Affairs Department provides regulatory support for Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power") and West Penn Power Company ("West Penn") (each of which may be referred to as "Company" or collectively as the "Companies"). I am responsible to the Director of Rates & Regulatory Affairs for the development, coordination, preparation and presentation of the Companies' accounting and financial data in all their rate-related matters before the Pennsylvania Public Utility Commission ("PUC" or "Commission") and the Federal Energy Regulatory Commission ("FERC"), as well as the preparation of statements and reports addressing, among other things,

energy costs, non-utility generation ("NUG") costs, quarterly earnings, and other financial matters. Also, I am responsible for the administration of the Companies' retail and wholesale tariffs, the development of retail electric rates, and the promulgation of rules and regulations ensuring uniform tariff administration and interpretation.

Q. What is your educational and professional background?

A. I obtained a Masters Degree in Business Administration from Pace University in 1976. I am also a graduate of Brooklyn College where I received a Bachelor of Science degree with a major in Economics. I have over thirty-eight years of experience with FirstEnergy Service Company and GPU Energy. My work experience is more fully described in Appendix A.

Q. Have you previously testified in regulatory proceedings?

A. Yes. As set forth in Appendix A, I have previously testified before the Commission, as well as the New Jersey Board of Public Utilities, the New York State Public Service Commission and, at the federal level, before FERC.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying in this proceeding on behalf of Met-Ed, Penelec, Penn Power and West Penn. My testimony equally applies to all of the Companies, unless otherwise stated.

Q. Please describe the purpose of your direct testimony.

A. The general purpose of my testimony is to describe and support: (i) various accounting, rate case, and other financial data that are being submitted in response to the filing requirements for an electric utility base rate case proceeding; (ii) the budget level of capital and operation and maintenance ("O&M") expenses; (iii) ratemaking adjustments to the budgeted test year rate base and operating income statement; (iv) the rolling into base rates of smart meter costs; (v) the removal of universal service costs for West Penn and their proposed recovery through a new reconciliation rider; (vi) the proposed treatment of deferred storm damage expenses and recovery of ongoing storm damage costs; and (viii) capital and O&M costs associated with the Commission's directive that electric distribution companies ("EDCs") accelerate customer switching of electric generation suppliers ("EGSs").

Q. Have you prepared exhibits to accompany your testimony?

A. Yes. Met-Ed Exhibits RAD-1 through RAD-64, Penelec Exhibits RAD-1 through RAD-64, Penn Power Exhibits RAD-1 through RAD-64 and West Penn Exhibits RAD-1 through RAD-64 (collectively, Exhibits RAD-1 through RAD-64) were prepared by me or under my supervision. Of these, my testimony will focus primarily on Exhibit RAD-1, which sets forth each Company's proposed rate base at April 30, 2016, i.e., the end of the fully projected future test year ("FPFTY") being utilized in this proceeding, and RAD-2, which provides a detailed income statement and support for certain normalization and annualization adjustments to

the budgeted FPFTY data. The remaining exhibits, for the most part, comprise responses to those Commission base rate filing requirements for which I am responsible.

Q. Please identify those witnesses whose testimony relates to and supports your testimony and exhibits.

A. Kimberlie L. Bortz (Met-Ed/Penelec/Penn Power/West Penn Statement No. 3) describes and supports the Storm Damage Recovery Riders proposed for all four Companies and the Universal Service Cost ("USC") Rider proposed for West Penn.

Kevin M. Siedt (Met-Ed/Penelec/Penn Power/West Penn Statement No. 4) supports the pro forma levels of energy sales and normalized revenues utilized to determine the Companies' need for rate relief. Mr. Siedt also details the Companies' proposed rate design and various rider modifications.

Hillary E. Stewart (Met-Ed/Penelec/Penn Power/West Penn Statement No. 5) explains the cost of service study she performed along with how various cost of service components (e.g., rate base, expenses) attributable to FERC jurisdictional service were identified and removed from the determination of the Companies' distribution revenue requirement.

Patricia M. Larkin (Met-Ed/Penelec/Penn Power/West Penn Statement No. 6) supports the Companies' cash working capital requirements.

Laura W. Gifford (Met-Ed/Penelec/Penn Power/West Penn Statement No. 7) describes and supports the normalization of uncollectible accounts expense, the unbundling of West Penn's generation uncollectible accounts expense, and the proposed roll-in to base rates of smart meter capital and O&M expenses.

Michael J. Vilbert (Met-Ed/Penelec/Penn Power/West Penn Statement No. 9) develops a range of the cost of equity capital to be utilized in the calculation of the Companies' overall rates of return.

Steven R. Staub (Met-Ed/Penelec/Penn Power/West Penn Statement No. 10) presents the Companies' proposed capital structure ratios and weighted average costs of long-term debt. In addition, he supports the Companies' requested return on common equity of 10.9%.

II. ACCOUNTING AND FINANCIAL DATA

Q. Do the Companies adhere to a system of accounts prescribed by the Commission?

A. Yes. The Companies' accounting records are maintained in accordance with the Commission's regulations at 52 Pa. Code Sec. § 57.41 *et seq.* and in conformity with the Uniform System of Accounts prescribed by the FERC and adopted by the Commission.

Q. Are the Companies' accounting records audited?

A. Yes. The Companies' financial records are audited at least annually by an independent certified public accounting firm. In addition, the FERC conducts

periodic compliance audits to confirm that the Companies are keeping their accounts in conformity with the Uniform System of Accounts. In addition to conducting its own audits, the staff of the PUC reviews the findings of FERC's audits. Other independent agencies also have the authority to audit the Companies' records on a recurring basis, including the Internal Revenue Service ("IRS") and the Securities and Exchange Commission ("SEC"). In addition, the PUC audit staff and the Pennsylvania Department of Revenue staff perform annual audits of the cost recovery rider mechanisms and sales and use tax filings.

Q. Have original cost determinations been made of the Companies' utility plant?

A. Yes. For Met-Ed, an original cost determination was made as of December 31, 1944, for which approval orders were issued by the PUC on December 11, 1945 at EOC Docket No. 27 and for Edison Light and Power Company (which was subsequently merged with Met-Ed) on November 12, 1946 at Docket No. 11. In 1948, the Company filed with the Commission a basic plan for maintaining its continuing property records. The PUC accepted and approved that plan on April 19, 1948.

For Penelec, an original cost determination was made as of December 31, 1943, by Commission Order dated January 15, 1945 at Docket Nos. EOC 32, MGOC 17, EOC 7, EOC 13, EOC 14, EOC 22 and EOC 44. Original cost determinations were also made for the following major companies which were later merged into Penelec: Pennsylvania Edison Company at Docket Nos. EOC 31 and MGOC 16

by Order dated November 1, 1946 approving balances at July 2, 1946; Northern Pennsylvania Power Company at Docket No. EOC 29 by Order dated January 2, 1946 approving balances at December 31, 1944; and Home Electric Company at Docket No. EOC 21 by Order dated August 20, 1945 approving balances at January 1, 1938.

For Penn Power, an original cost determination was approved by the Commission in the mid-1940's. A subsequent original cost determination was made as part of the Commission's April 6, 1984 Order in Penn Power's base rate proceeding at Docket No. R-832409 (58 PaPUC 305, 60 PUR 4th 593). In that case, the Commission, at the recommendation of the Office of Trial Staff, directed Penn Power to develop its revenue requirement on the basis of its book reserve for depreciation and to convert to the average remaining life method of depreciation and, in so doing, established depreciated original cost plant values to be utilized henceforth.

For West Penn, an original cost determination was made as of December 31, 1943, by Order of this Commission dated July 10, 1945 at Docket No. 50.

The Companies have, since the dates noted above, maintained their continuing property records in accordance with the approved plans.

III. BUDGETS

Q. Mr. D'Angelo, are you familiar with the process by which Met-Ed, Penelec, Penn Power and West Penn budget future capital expenditures, revenues and operating expenses?

A. Yes, I am. In general, the Companies' budgeting process involves: (1) the establishment of documented and well-supported goals, objectives and guidelines; (2) intensive reviews and refinements by all levels of management and functional staffs; and (3) careful scrutiny and ultimate approval by appropriate senior management.

Q. How were those budgets utilized to develop the Companies' claimed revenue requirements in these proceedings?

A. They provided the starting point for determining the Companies' claimed rate base at April 30, 2016 and operating income for the twelve months ending that date. Specifically, I consolidated budgeted monthly data for the months of May through December from the 2015 forecast and the months of January through April from the 2016 forecast to develop the "Per Budget" amounts set forth in Column 1 of Exhibits RAD-1 and RAD-2.

Q. Did you update any of the budgeted data for purposes of these rate filings?

A. Yes. Since the completion of the capital budget, certain revisions were made to the forecasted capital structures of the Companies and those changes have been reflected by Mr. Staub in his testimony and exhibits. Also, the Companies made certain changes to the test year for: (1) updated tax depreciation (Exhibits RAD-

33); (2) the provision for deferred income taxes (Exhibits RAD-41); and (3) accumulated deferred income taxes (Exhibits RAD-35).

Q. What opinion, if any, do you have as to the budgeted levels of capital and expense?

A. In my opinion, the budgeted levels of capital and expense are reasonable estimates of what Met-Ed, Penelec, Penn Power and West Penn can expect to experience during the FPFTY prior to recognition of the appropriate ratemaking adjustments reflected in Exhibits RAD-1 and RAD-2.

IV. RATEMAKING ADJUSTMENTS TO BUDGETED TEST YEAR DATA

A. Rate Base at April 30, 2016 (Exhibits RAD-1)

Q. Please generally describe Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-1.

A. These exhibits, which are essentially identical in format, set forth, for each Company, its proposed overall distribution rate base and smart meter rate base at April 30, 2016. Column 1 on page 1 of Exhibits RAD-1 provides budgeted amounts; column 2 adjusts various components; and column 3 reflects the adjusted rate base. The remaining columns on page 1 break the adjusted rate base into separate distribution and smart meter rate base elements.

The adjustments to the budgeted rate base data, along with a detailed explanation of each adjustment, are contained on pages 2 through 11 of Met-Ed, Penelec, and

West Penn, and Penn Power Exhibits RAD-1 and are referenced on page 1 by adjustment number. The adjustments are designed to accomplish the following:

- Remove FERC gross plant and depreciation reserves (Met-Ed, Penelec and West Penn);
- Reflect adjusted depreciation reserves applicable to rate base;
- Eliminate American Transmission Systems, Inc. ("ATSI") plant and depreciation reserves in accordance with the settlement at Docket No. A-110450F0016 (Penn Power);
- Eliminate plant held for future use;
- Reflect the roll-in to base rates of smart meter investment and related depreciation reserves;
- Reflect cash working capital requirements;
- Reflect material and supplies ("M&S") inventories;
- Reflect unamortized deferred storm damage expenses as an addition to rate base (Met-Ed, Penelec and West Penn);
- Reflect the transfer of unrecovered legacy meter investment from plant in service to a regulatory asset account;
- Adjust accumulated deferred income taxes – liberalized depreciation; and
- Adjust operating reserves, net of tax, to remove FERC jurisdictional allocations (Met-Ed, Penelec and West Penn).

Q. Please describe Adjustment No. 1 to Electric Plant in Service.

A. This adjustment eliminates from plant in service accounts: (1) Asset Retirement Costs ("ARC"); (2) FERC Transmission Plant, including allocated portions of Intangible and General Plant, based on the results of a separations study described by Ms. Stewart in Met-Ed/Penelec/Penn Power/West Penn Statement No. 5; (3) legacy meters, as directed by the Commission in the Final Order in the Companies' Smart Meter Deployment Plan at Docket Nos. M-2013-2341990 (Met-Ed), M-2013-2341991 (Penelec), M-2013-2341993 (Penn Power), and M-2013-2341994 (West Penn); and (4) in the case of Penn Power, ATSI plant in accordance with the settlement at Docket No. A-110450F0016.

Q. What are ARC costs?

A. An ARC applies to all legal obligations associated with the retirement of long-lived assets that result from construction under Financial Account Standards Board Statement No. 143 ("FAS-143)." FAS-143 requires that the fair value of a liability for an asset's retirement obligation ("ARO") be recognized in the period in which it is incurred. The associated ARC is capitalized as part of the carrying amount of the long-lived assets. An ARC increases the carrying amount of a long-lived asset when a liability for an ARO is recognized and is depreciated over the life of the asset. The ARC and related depreciation reserve are excluded from rate base, while the associated depreciation expense is excluded from the income statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18, Asset Retirement Obligations.

Q. What is the Companies' position on Plant Held for Future Use?

A. Historically, the Companies claimed in rate base those investments in Plant Held for Future Use that were expected to be utilized within ten years of the test period. The ten-year window reflected the Commission's prior policy of allowing such investments where definitive plans for utilizing the investment within the ten-year period existed. Under current Commission policy, investments in Plant Held for Future Use are excluded from rate base, but allowed to accrue carrying charges provided they satisfy the ten-year test. Adjustment No. 2 is designed to comply with that policy.

Q. Please describe Adjustment No. 3 to Depreciation Reserve - Electric Plant in Service.

A. This adjustment removes from the budgeted depreciation reserve those portions attributable to the plant eliminated in Adjustment No. 1.

Q. What is the purpose of Adjustment No. 4?

A. This adjustment includes the Companies' cash working capital requirements described by Ms. Larkin in Met-Ed/Penelec/Penn Power/West Penn Statement No. 6 and computed by her in Met-Ed, Penelec, Penn Power and West Penn Exhibits PML-1.

Q. Please describe Adjustment No. 5 to M&S inventories.

A. This adjustment includes each Company's allocated portion of the materials and supplies inventory maintained by the FirstEnergy Service Company at March 31,

2014. The historic test year-end balance was used because the Companies do not budget M&S inventories. Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-13 provide a monthly breakdown of M&S inventories for the thirteen months ended March 31, 2014.

Q. What is the purpose of Adjustment No. 6?

A. Adjustment No. 6 includes in claimed rate base certain storm damage costs, the recognition of which has been deferred in accordance with Commission order. The specific costs deferred, and citations to the Commission orders approving their deferral, are provided for Met-Ed, Penelec, and West Penn on page 7 of the exhibits.

Q. Please describe the adjustment for legacy meters.

A. In its March 6, 2014 Order at Docket Nos. M-2013-2341990, et al., approving the Companies' Smart Meter Deployment Plans, the Commission directed that the cost of removing legacy meters (i.e., meters to be replaced by the installation of smart meters) be charged to the regulatory asset account containing the legacy meters and recovered, along with the unrecovered investment in those meters, over the remaining lives of those meters. As noted previously, Adjustment No. 1 transfers the investment in legacy meters that will remain unrecovered as of April 30, 2016, to a regulatory asset account. Adjustment No. 7 adds back to rate base the regulatory asset account, net of accrued depreciation, plus the estimated cost of removal.

Q. Please describe the adjustment of Accumulated Deferred Income Taxes – Liberalized Depreciation.

A. Adjustment No. 8 adjusts the budgeted deferred tax balances for liberalized depreciation, excluding the impact of Statement of Financial Accounting Standards ("SFAS") No. 109 deferrals, to eliminate: (1) deferred income taxes associated with Three Mile Island Unit No. 2 (Met-Ed and Penelec); (2) deferred income taxes associated with other generation (Met-Ed); (3) other excludable items (capital leases); (4) remaining state income tax deferrals including the benefit of those income taxes; and (5) an allocated portion of the remaining federal deferred income taxes associated with FERC Transmission Plant (Met-Ed, Penelec and West Penn).

Q. Please describe the adjustment proposed to operating reserves.

A. Adjustment No. 9 adjusts operating reserves, net of accumulated deferred income taxes, to eliminate an allocated portion associated with FERC transmission operations (Met-Ed, Penelec and West Penn).

Q. After taking into account the foregoing adjustments, what is Met-Ed's claimed distribution rate base?

A. Met-Ed's claimed distribution rate base equals $1,412,965,000, of which $28,109,000 represents the roll-in of smart meter investment.

Q. What is Penelec's claimed distribution rate base?

A. Penelec's claimed distribution rate base equals $1,540,298,000, of which $30,884,000 represents the roll-in of smart meter investment.

Q. What is Penn Power's claimed distribution rate base?

A. Penn Power's claimed distribution rate base equals $358,929,000, of which $24,326,000 represents the roll-in of smart meter investment.

Q. What is West Penn's claimed distribution rate base?

A. West Penn's claimed distribution rate base equals $1,287,287,000, of which $87,918,000 represents the roll-in smart meter investment.

Q. What is contained on page 11 of Exhibits RAD-l?

A. This page sets forth, for each Company, its claimed overall rate of return, including its proposed capital structure ratios, weighted average cost of long-term debt and requested return on common equity. Those findings, which are presented and supported by Mr. Staub and Dr. Vilbert, are summarized below:

1. Met-Ed	Capital Structure Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.0%	5.21%	2.60%
Preferred Stock	0.0%	---	---
Common Equity	50.0%	10.9%	5.45%
	100.0%		8.05%

2. Penelec	Capital Structure Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.1%	5.72%	2.87%
Preferred Stock	---	---	---
Common Equity	49.9%	10.9%	5.44%
	100.0%		8.31%

3. Penn Power	Capital Structure Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	49.9%	6.12%	3.05%
Preferred Stock	---	---	---
Common Equity	50.1%	10.9%	5.46%
	100.0%		8.51%

4. West Penn	Capital Structure Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	49.9%	5.38%	2.68%
Preferred Stock	---	---	---
Common Equity	50.1%	10.9%	5.46%
	100.0%		8.14%

B. Statement of Operating Income For the 12 Months Ending April 30, 2016 (Exhibits RAD-2)

Q. What is contained in Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-2?

A. Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-2 contain the budgeted and pro forma statements of net utility operating income for the FPFTY ending April 30, 2016. The first three pages summarize the budgeted and adjusted results of operations at present and proposed rates; the next five pages break down each Company's revenue requirement by component part (e.g., distribution, smart meter roll-in); and the remaining pages, starting at page 9, document the specific adjustments made to normalize and annualize the budgeted data.

The adjustments are designed to accomplish the following:

- Annualize number of customers, usage and sales at end-of-test-year levels;

- Roll into base rates revenues associated with the State Tax Adjustment Surcharge ("STAS");

- Eliminate non-jurisdictional "Other Operating Revenues," as applicable;

- Annualize payroll and employee benefit costs to reflect anticipated employee levels and benefits;

- Calculate net negative salvage based on a five-year average of actual net salvage, consistent with Commission practice;

- Normalize pension expense to reflect a ten-year average of cash contributions consistent with the approach approved by the Commission in prior proceedings;

- Normalize other post-employment benefits ("OPEBs") to reflect the actual ongoing level of service costs charged to expense consistent with the approach used in the past with Commission approval;

- Normalize depreciation accruals to reflect utility plant in service as of the end of the FPFTY;

- Normalize rate case expenses to reflect a two-year cost recovery period;

- Eliminate non-jurisdictional O&M expenses;

- Normalize O&M expenses associated with serving new customers;

- Eliminate the Universal Service program costs included in West Penn's budget, as such costs will be recovered through West Penn's proposed USC Rider;

- Amortize the unrecovered investment in "legacy" meters being replaced by smart meters over a five-year period;

- Amortize deferred storm damage O&M expenses over a three-year period (Met-Ed, Penelec and West Penn);

- Amortize West Penn's residual merger credit balance to residential customers over two years;

- Remove default service-related uncollectible accounts expense from distribution revenue requirement (West Penn); and

- Adjust taxes other than income including, for Penn Power, rolling the 5.9% Gross Receipts Tax ("GRT") into base rates and all of its applicable cost recovery riders.

Q. What level of GRT has been collected in Penn Power's base rates and its various cost recovery riders?

A. The Commonwealth of Pennsylvania requires Penn Power to pay GRT at the statutory rate of 5.9%. However, Penn Power has been recovering GRT in base rates and cost recovery riders at a 4.4% tax rate and has been recovering the remaining 1.5% of the statutory rate in its STAS.

Q. How does rolling the STAS into base rates impact the Penn Power's various cost recovery riders?

A. Rolling the STAS into Penn Power's base rates requires each of the Company's cost recovery riders to recover fully that rider's GRT revenue requirement. Consequently, each cost recovery rider reflects a shortfall in its GRT recovery, which is made up through an applicable increase in revenue requirements shown on page 2 of Penn Power Exhibit RAD-2. However, the revenue requirements for the Price-To-Compare ("PTC"), USC, Energy Efficiency Conservation Charge ("EE&C-C"), Default Service Support, and Solar Photovoltaic Requirements Charge ("SPVRC") Riders will be updated. Specifically, the actual rates to be imposed under the various cost recovery riders will have their respective GRT component updated as part of the Penn Power compliance filing at the time new base rates approved in this proceeding are implemented. Because the SMT-C

Rider is being rolled into base rates, its revenue requirement will reflect GRT at the statutory 5.9% rate.

Q. Are the Companies seeking to recover any acquisition premium or other transaction costs associated with the FirstEnergy/GPU or FirstEnergy/Allegheny mergers as part of the revenue requirements in this case?

A. No. There is no provision in the budget for, nor has any adjustment been made to include, an amortization of acquisition premiums or other transaction costs associated with either of those mergers.

Q. Please describe Adjustment No. 1.

A. This is an adjustment to base operating revenues to: (1) annualize changes in number of customers; (2) roll-in STAS revenues; (3) normalize the sales and revenue effects of energy efficiency measures implemented or to be implemented under the Companies' Energy Efficiency and Conservation Plans and to reflect behind-the-meter generation; (4) normalize Other Revenue (Met-Ed, Penn Power, and West Penn); (5) street lighting (Penelec); and (6) eliminate unbilled revenue. Parts (1) through (5) of this adjustment are discussed in detail by Mr. Siedt in Met-Ed/Penelec/Penn Power/West Penn Statement No. 4. I address item (6). By way of background, unbilled revenue has been included in the budget projection to reflect revenues for service rendered but not billed as of the end of each accounting period. Items that produce unbilled revenue include such things as increases in rates and increases in the number of customers. In developing pro

forma revenues for ratemaking purposes, separate adjustments are being made to annualize and normalize the revenue effect of such factors. Therefore, to eliminate any duplication of revenue for ratemaking purposes, unbilled revenue must be eliminated, which is done in Adjustment No. 1.

Q. Please describe Adjustment No. 2.

A. This adjustment eliminates revenues projected to be billed under the Companies' STAS Riders. Because all state taxes are included in distribution base rate revenue requirement, no revenues will be billed under the STAS Rider. As the Companies did not forecast any charge under their STAS Rider, the adjustment is zero.

Q. Please describe Adjustment No. 3.

A. This adjustment eliminates non-jurisdictional FERC transmission revenues from electric revenues projected for the FPFTY.

Q. What is the purpose of Adjustment No. 4 to Distribution Expense?

A. This adjustment: (1) normalizes each of the Companies' and FirstEnergy Service Company's payroll expense to reflect year-end wage and employee levels; (2) eliminates non-jurisdictional transmission expenses; and (3) excludes the transmission portion of the amortization of gains or losses to reacquire debt, where applicable, based on the results of the separations study described by Ms. Stewart in Met-Ed/Penelec/Penn Power/West Penn Statement No. 5.

Supporting Schedule No. 1 develops the payroll expense to reflect year end wage and employee levels for both Company and FirstEnergy Service Company employees. The O&M payroll expense for each Company and FirstEnergy Service Company is then allocated to individual Price to Compare, Transmission, Distribution, Customer Accounts, Customer Service and Administrative and General components. These amounts are later utilized in subsequent adjustments.

Q. Please describe Adjustment No. 5 to Customer Accounts Expense.

A. Customer Accounts expense is adjusted to reflect year end wage and employee levels for each Company and FirstEnergy Service Company personnel (developed in Adjustment No. 4), increased costs associated with added new customers and interest on customer deposits.

Supporting Schedule No. 1 develops the Other O&M expenses associated with serving new customers reflected in Adjustment No. 1. The Commission has previously approved an adjustment to customer accounts expense in recognition of this increased cost. This cost is estimated by determining the ratio of non-payroll customer account expense to distribution revenues from customers and applying this ratio to the additional revenue received from increased customers.

Supporting Schedule No. 1 also captures the cost of interest the Companies are required to pay on customer deposits since the customer deposits are deducted from rate base.

Q. What is the purpose of Adjustment No. 6 to Customer Service and Informational Expense?

A. Customer Service and Informational Expense is adjusted to reflect year end wage and employee levels for each Company and FirstEnergy Service Company that were developed in Adjustment No. 4, Supporting Schedule No. 1.

Q. Please describe Adjustment No. 7 to Administrative and General Expense.

A. Administrative and General Expense is adjusted to reflect: (1) year-end wage and employee levels for each Company and FirstEnergy Service Company that were developed in Adjustment No. 4, Supporting Schedule No. 1; (2) OPEBs at the service cost level; (3) pension expense at the ten-year average cash contribution level; (4) employee benefit expense at year-end personal and wage levels; (5) the elimination of non-jurisdictional administrative and general expenses based on the results of the separations study sponsored by Ms. Stewart (Met-Ed/Penelec/Penn Power/West Penn Statement No. 5); (6) inclusion of rate case expenses incurred in the current proceeding normalized over a two-year period; (7) the elimination of budgeted rate case expenses; and (8) the amortization of costs to allow for accelerated, three day, customer switching from one supplier to another based upon information contained in Exhibits RAD-64.

Supporting Schedule No. 1 adjusts the budgeted level of OPEB expenses to the service cost level. The budgeted OPEB expense consists of the current service cost, adjustments to prior years' service costs, and the financing component. The service cost represents the actuarial present value of benefit liabilities accrued

under the plan benefit formula for services rendered during the test year. Inclusion of the service cost in rates provides for recovery of the current cost of benefits earned by plan participants. Any excess or shortfall related to the expected return on plan assets is excluded because its inclusion would artificially reduce or increase total costs and result in the recovery of more or less than the normal ongoing cost of service. The adjustment to restate OPEB expense at the current service cost level was adopted by the Commission at Docket Nos. R-00061366 and R-00061367.

Supporting Schedule No. 2 normalizes the budgeted level of pension expense to appropriately reflect a ten-year historical average level of actual cash contributions to the pension plan under the methodology that was adopted by the Commission at Docket Nos. R-00061366 and R-00061367.

Supporting Schedule No. 3 uses the O&M payroll expense developed in Adjustment No. 4, Supporting Schedule No. 1 to normalize the employee benefits costs charged to Administrative and General expense.

Q. Please describe Adjustment No. 8 to Depreciation Expense.

A. Budgeted Depreciation Expense is adjusted: (1) to reflect the application of average remaining life depreciation rates to claimed plant in service; (2) to remove depreciation expense attributable to non-jurisdictional assets; (3) to restate the cost of removal/salvage expense on a five-year average basis consistent

with Commission practice; and (4) to amortize the unrecovered investment in legacy meters at April 30, 2016 over five years.

Q. Please describe Adjustment No. 9.

A. This adjustment increases expenses to amortize storm damage expenses that have been deferred with the Commission's prior approval. The specific costs deferred, and a citation to the Commission Order approving their deferral, is provided for each Company on page 24 of the exhibits. This adjustment also eliminates credits that were budgeted in this account for rate case expenses and legacy meters. The underlying expenses were inadvertently budgeted to Administrative and General Expense but were removed from the budget in Adjustment No. 7.

Q. Please describe Adjustment No. 10.

A. Taxes Other Than Income Taxes included in the budget were adjusted to: (1) eliminate non-jurisdictional payroll taxes: (2) reflect GRT at 5.9% for normalized sales revenues; (3) eliminate non-jurisdictional expense portions of Capital Stock Tax, the Public Utility Reality Tax, and other real estate taxes; and (4) adjust payroll tax expense based on annualized payroll and employee levels.

The adjustments to remove the non-jurisdictional portion of payroll taxes, the Capital Stock Tax, Public Utility Reality Tax, and other real estate taxes are based on the results of the separation study performed by Ms. Stewart.

Supporting Schedule No. 1 shows the calculation of Federal Insurance Contributions Act ("FICA") tax associated with the annualized O&M payroll expense developed in Adjustment No. 4.

Q. Please describe briefly the computation of federal and state income taxes as reflected in Adjustment No. 11.

A. This schedule begins with the computation of the $57,147,000 net operating income before income taxes from data shown on page 1 of Met-Ed Exhibit RAD-2 (line 5 less line 14 of column 3 on page 1); $100,404,000 net operating income before income taxes from data shown on page 1 of Penelec Exhibit RAD-2 (line 5 less line 14 of column 3 on page 1); $22,637,000 net operating income before income taxes from data shown on page 1 of Penn Power Exhibit RAD-2 (line 5 less line 14 of column 3 on page 1), and $67,368,000 net operating income before income taxes from data shown on page 1 of West Penn Exhibit RAD-2 (line 5 less line 14 of column 3 on page 1). The revenues and expenses used to calculate the federal and state income taxes in Adjustment No. 11 are divided into columns corresponding to the components shown on pages 1-3 of these exhibits (Distribution, PTC, USC, EE&C-C, Smart Meter Technologies Charge Rider, DSS Rider, SPVRC, NUG and Storm Cost Recovery Rider) to derive net operating income before income taxes. From that amount, interest was deducted. Interest was calculated by multiplying the adjusted rate base by the weighted average cost of long-term debt. The resulting figure is net income before income taxes a shown on line 10.

Two adjustments (lines 11 and 14) were made to increase taxable income. The first reflects the five-year amortization of net salvage. The second increases net income by adding back the cash pension contribution included in pro forma O&M expenses, which is not a current deduction for tax purposes.

The remaining two adjustments (lines 12 and 13) are deductions from taxable income. The first adjusts depreciation to reflect accelerated depreciation, where permitted, on eligible property as of April 30, 2016. The second reflects cost of removal ($6,080,000 for Met-Ed; $8,872,000 for Penelec; $527,000 for Penn Power; $4,938,000 for West Penn) that may be claimed as a current deduction for tax purposes. The net amount of these adjustments is included in the net income before federal and state income taxes to determine the income subject to state income tax. The state and federal income tax calculations then follow. The state and federal income taxes are computed at the statutory rates of 9.99% and 35%, respectively.

Q. Please describe Adjustment No. 12.

A. This adjustment eliminates from the budgeted Provision for Deferred Income Taxes all deferred taxes except the federal deferred taxes associated with liberalized depreciation. Additionally, federal deferred taxes for liberalized depreciation are adjusted to reflect plant in service as of the end of the FPFTY. Detailed calculations of the federal deferrals are provided in Exhibits RAD-41.

The computation for post-1969 through 1980 “expansion” property is based on the difference between accelerated depreciation (calculated using the Sum of the Years Digits (“SYD”) method and taxable lives based on the Asset Depreciation Range (“ADR”)) and straight-line depreciation using “guideline” lives. The computation for 1981 and subsequent property begins by determining the difference between tax depreciation using the Accelerated Cost Recovery System (“ACRS”) and the Modified Accelerated Cost Recovery System (“MACRS”) and straight line depreciation (using book rates and tax basis).

The federal tax rate of 35% was applied to the amounts calculated in the manner described above and compared to the tax to be booked during the test year to determine the adjustment to deferred taxes.

The state deferred taxes associated with liberalized depreciation pertain only to FERC jurisdictional property and have been eliminated. The deferred taxes associated with other miscellaneous items have been eliminated because the associated income has not been included in the calculation of taxable income used to compute federal and state taxes included in each Company’s revenue requirement.

Q. Please describe Adjustment No. 13.

A. This adjustment eliminates the non-jurisdictional portion of investment tax credits based on the results of the separation study performed by Ms. Stewart.

Q. What is Met-Ed's claimed additional distribution revenue requirement?

A. Reflecting all of the adjustments to the budget data discussed above, Met-Ed's net utility operating income for the FPFTY at present rates is $29,730,000 (page 1, column 13, line 23). This amount, compared to the $113,767,000 shown on page 3, column 33, line 23, shows that $84,037,000 in additional return is required for Met-Ed to achieve an overall return of 8.05% on its distribution rate base. This translates into an additional base rate revenue requirement, or revenue deficiency under existing rates, of $152,643,000, as shown on page 2, column 23, line 1.

Q. What is Penelec's claimed additional distribution revenue requirement?

A. Reflecting all of the adjustments to the budget data discussed above, Penelec's net utility operating income for the FPFTY at present rates is $61,695,000 (page 1, column 14, line 23), after excluding ($726,000) allocated to the New York jurisdiction. This amount, compared to the $127,934,000 shown on page 3, column 34, line 23, shows that $66,239,000 in additional return is required for Penelec to achieve an overall return of 8.31% on its Pennsylvania jurisdictional distribution rate base. This translates into an additional base rate revenue requirement, or revenue deficiency under existing rates, of $120,316,000, as shown on page 2, column 24, line 1.

Q. What is Penn Power's claimed additional distribution revenue requirement?

A. Reflecting all of the adjustments to the budget data discussed above, Penn Power's net utility operating income for the FPFTY at present rates is $14,278,000 (page 1, column 13, line 23). This amount, compared to the $30,550,000 shown on

page 3, column 33, line 23, shows that $16,272,000 in additional return is required for Penn Power to achieve an overall return of 8.51% on its distribution rate base. This translates into an additional base rate revenue requirement, or revenue deficiency under existing rates, of $29,557,000, as shown on page 2, column 23, line 1.

Q. What is West Penn's claimed additional distribution revenue requirement?

A. Reflecting all of the adjustments to the budget data discussed above, West Penn's net utility operating income for the FPFTY at present rates is $61,502,000 (page 1, column 11, line 23). This amount, compared to the $104,785,000 shown on page 3, column 27, line 23, shows that $43,283,000 in additional return is required for West Penn to achieve an overall return of 8.14% on its distribution rate base. This translates into an additional base rate revenue requirement, or revenue deficiency under existing rates, of $78,619,000, as shown on page 2, column 19, line 1.

Q. What is contained in Exhibits RAD-3, RAD-4, RAD-5 and RAD-6?

A. Exhibits RAD-3 and RAD-5 set forth each Company’s rate base at March 31, 2015 and 2014, respectively. Exhibits RAD-4 and RAD-6 set forth each Company’s operating income statements with normalizing adjustments for the future test year (twelve months ended March 31, 2015) and the historic test year (twelve months ending March 31, 2014), respectively.

While the specific numbers differ, these two sets of exhibits are identical in format and concept to Exhibits RAD-1 and RAD-2 and the description of the filing format in my testimony applies equally to them.

V. REGULATORY TREATMENT OF STORM DAMAGE COSTS

Q. How has the Commission historically treated storm damage costs for ratemaking purposes?

A. As in the case of other operating expenses, utilities have been allowed to include a normal, ongoing level of storm damage costs in their base rate revenue requirement. In addition, utilities have been permitted to request authorization to defer, for accounting purposes, extraordinary storm damage costs, with the understanding that rate recovery of the deferred costs would be addressed in a future base rate proceeding. In accordance with that policy and prior rulings by the Commission, the Companies have included in their FPFTY revenue requirement a normalized level of storm damage costs and, in the case of Met-Ed, Penelec and West Penn, rate recovery of previously authorized deferrals (see Exhibits RAD-1, p. 7 and Exhibits RAD-2, p. 24).

Q. Are the Companies proposing any changes to the recovery of storm damage expense in this filing?

A. Yes. The Companies are proposing to institute a Storm Damage Recovery Rider to provide for the annual true-up of actual storm damage O&M expenses. The Riders would impose either a charge, if actual storm damage expenses exceeded the base rate amount, or a credit if actual storm damage expenses were less than

the base rate amount. Ms. Bortz, in Met-Ed/Penelec/Penn Power/West Penn Statement No. 3, describes the Storm Damage Recovery Riders proposed by the Companies.

Q. What is the normalized, ongoing amount of storm damage O&M expense budgeted for the twelve months ending April 30, 2016?

A. Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-63 set forth budgeted storm damage expense for the twelve months ending April 30, 2016, and the twelve months ending March 31, 2015, and actual storm damage expense for the twelve months ended March 31, 2014, along with three additional historical calendar years. The level of storm damage O&M expense to be recovered through base rates is $6,625,000 at Met-Ed, $5,111,000 at Penelec, $657,000 at Penn Power, and $5,276,000 at West Penn.

VI. COSTS ASSOCIATED WITH IMPLEMENTATION OF ACCELERATED CUSTOMER SWITCHING

Q. You noted previously that the Commission had ordered EDCs to accelerate the processing of supplier switching requests. What led to this directive?

A. Weather conditions earlier this year were unusually harsh and resulted in unanticipated fluctuations in wholesale and retail energy prices. Customers with variable rate supply contracts were adversely impacted by these developments and, in response, the Commission launched a Rulemaking with the goal of ensuring that customers could quickly switch electric suppliers to mitigate their exposure to the types of price fluctuations they had experienced.

Q. How did the Commission proceed with the Rulemaking?

A. On March 18, 2014 at Docket No. L-2014-2409383, the Commission issued a Secretarial Letter informing EDCs, the Office of Consumer Advocate and the Office of Small Business Advocate of a proposed Rulemaking to amend existing Regulations at 52 Pa. Code, Chapter 57. The Rulemaking directed EDCs to take the necessary steps to permit retail customers to switch suppliers within three days or less. The Commission recognized the proposed changes were significant and provided for a comment period.

Q. What was the outcome of the Commission's Rulemaking at Docket No. L-2014-2409383?

A. The Commission revised its regulations to facilitate accelerated customer switching in its Order at Docket No. L-2014-2409383, entered April 3, 2014. The Rulemaking Order ensures customers may easily and quickly switch electric suppliers in an effort to mitigate potential price impacts related to variable priced contracts and fluctuations in the wholesale and retail energy markets. The Rulemaking Order also allows for the recovery in an EDC's next base rate proceeding of the cost incurred to comply with the accelerated switching requirements.

Q. What is contained in the Companies' respective Exhibits RAD-64?

A. Exhibits RAD-64 identify the incremental O&M expenses and capital expenditures to be incurred by each Company to comply with the Commission's three-day switching requirement. Those costs are then added to each Company's

revenue requirement through an adjustment to Administrative and General expense on page 18 of Exhibits RAD-2. As indicated on page 1 of Exhibits RAD-64, the Companies are proposing that the additional capital expenditures be amortized over five years.

VII. OTHER FILING REQUIREMENTS

Q. Would you briefly describe Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-7 through RAD-62?

A. Yes. 52 Pa. Code § 53.53 contains the data requirements to be filed in a major rate case. Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-7 through RAD-60 contain the Companies' responses to various data requests assigned to me. Each exhibit cites the specific filing requirement to which it is responding and is followed by the Companies' response.

Met-Ed, Penelec, Penn Power, and West Penn Exhibits RAD-61 list the types of advertising included in expenses for the test year and the immediately preceding year, in accordance with Section 1316(c) of the Public Utility Code, 66 Pa. Code Sec. § 1316(c). Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-62 respond to the PUC Statement of Policy at 52 Pa. Code § 69.36, entitled "Performance criteria regarding energy supply alternatives." This Statement of Policy identifies six areas for review in rate proceedings pertaining to an electric utility's efforts to encourage the development of cost effective energy supply alternatives. Met-Ed, Penelec, Penn Power and West Penn Exhibits RAD-62

address five of the six identified areas. Mr. Siedt addresses the remaining area in Met-Ed/Penelec/Penn Power/West Penn Statement No. 4.

VIII. CONCLUSION

Q. Please summarize your testimony and recommendations.

A. Inclusive of the roll-in of smart meter costs, Met-Ed has supported an increase in base rate revenue requirements of $152,643,000; Penelec an increase of $120,316,000; Penn Power an increase of $29,557,000; and West Penn an increase of $78,620,000 (including the separate USC Rider).

In addition, West Penn is proposing a separate reconciling cost recovery rider for universal service costs as explained by Ms. Bortz in Met-Ed/Penelec/Penn Power/West Penn Statement No. 3. If the USC Rider is not adopted by the Commission, an additional revenue requirement of $29,565,000 (see West Penn Exhibit RAD-2, page 7) would need to be reflected in West Penn's base distribution rates.

Finally, and as previously discussed, the Companies are proposing to implement Storm Damage Recovery Riders to provide for the recovery of storm damage expenses in excess of – or the crediting of storm damage expenses falling below – a normalized level of storm damage costs reflected in base distribution rates. Ms. Bortz describes these Riders in Met-Ed/Penelec/Penn Power/West Penn Statement No. 3.

Q. Mr. D’Angelo, does this complete your direct testimony?

A. Yes, it does.

Resume: Education and Experience of Richard A. D'Angelo

Education:

1972	Bachelor of Science Degree in Economics - Brooklyn College
1976	Master of Business Administration Degree in Finance - Pace University

Experience:

9/72 - 11/76	Accountant and Supervisor - Bankers Trust Company
11/76 - 2/81	Employed as Accountant within Regulatory Accounting Area - Metropolitan Edison Company ("Met-Ed")
2/81 - 2/82	Senior Accountant within Regulatory Accounting Area with special emphasis on rate-related matters (Met-Ed)
2/82 - 2/83	Supervisor - Rates and Financing (Met-Ed)
2/83 - 3/95	Manager - Rate Revenue Requirements within the Rate Department (Met-Ed)
3/95 - 8/96	Manager - Regulatory Liaison within the Regulatory Affairs and Pricing Department (Met-Ed/Penelec)
8/96 – 11/01	Manager - Rate Activity within the Rate Department (GPU Energy)
11/01 – Present	Manager – Rates & Regulatory Affairs- Pennsylvania (FirstEnergy Service Company)

Prepared and presented testimony in the following rate-related cases:

Pa. P.U.C. Cases: Docket Nos. P-2011-2273650
P-2011-2273668
P-2011-2273669
P-2011-2273670
A-2010-2176520
A-2010-2176732
P-2010-2157862
P-2009-2093053
P-2009-2093054
P-00072305
P-00072259
P-00062235
R-00061366
R-00061367
P-00062213

P-00062214
P-00052149
P-00062214
P-00052188
A-110550F0160
R-00016851C0001
R-00016852C0001
R-00016853C0001
A-110300F.0095
A-110400F.0040
P-00001860
P-00001861
P-00001837 (Phase 2)
P-00001838 (Phase 2)
R-00974008 (Phase 1)
R-00974009 (Phase 1)
P-00971215
P-00971216
P-00971217
P-00971223
P-00971278
P-00961015
P-00950968
A-110300 F0067
R-922314
P-0092087
P-00900450
R-860384
R-842770
R-832549
R-822249
I-900005
P-890366
M-FACE 8707
M-FACE 8602
M-FACE 8506
M-FACE 8404
M-FACE 8203

M-FACE 8104
M-870171 C001

NJ B.P.U Case: Docket No. EO03121014
Docket No. ER12111052

FERC Cases: Docket Nos. ER-90-388-000 and ER-90-522-000
ER-87-34-001
ER-83-173

Assisted in development and preparation in the following rate cases:

Pa. P.U.C. Cases: Docket Nos. R-811601
R-80051196
R.I.D. 626

FERC Case: Docket No. ER-79-58

METROPOLITAN EDISON COMPANY
Rate Base At Original Cost
Normalized To Year-End Conditions at April 30, 2016
($000)

Line No.	Description	Per Budget	Adjustments and Normalizations	Adj No.	Total	Pa Juridictional Normalized Rate Base: Distribution	Smart Meter Costs	PA Jurisdictional Total
		(1)	(2)		(3)	(4)	(5)	(6) = (4) + (5)
	Electric Plant:							
1	Plant in service	$ 2,935,437	$ (669,581)	1	$ 2,265,856	$ 2,231,833	$ 34,023	$ 2,265,856
2	Plant held for future use	596	(596)	2	-	-	-	-
3	Construction work in progress - pollution control and safety	-	-		-	-	-	-
4	Total electric plant	$ 2,936,033	$ (670,177)		$ 2,265,856	$ 2,231,833	$ 34,023	$ 2,265,856
	Depreciation & Amortization Reserve:							
5	Plant in service	$ 1,055,494	$ (304,192)	3	$ 751,302	$ 747,774	$ 3,528	$ 751,302
6	Plant held for future use	-	-		-	-	-	-
7	Total depreciation & amortization reserve	$ 1,055,494	$ (304,192)		$ 751,302	$ 747,774	$ 3,528	$ 751,302
8	Net Electric Plant	$ 1,880,539	$ (365,985)		$ 1,514,554	$ 1,484,059	$ 30,495	$ 1,514,554
	Additions:							
9	Cash working capital	$ -	$ 147,828	4	$ 147,828	$ 147,828	$ -	$ 147,828
10	M&S inventories	-	14,493	5	14,493	14,493	-	14,493
11	Deferred storm damage	-	64,964	6	64,964	64,964		64,964
12	Legacy meters	-	53,794	7	53,794	53,794		53,794
13	Total additions	$ -	$ 281,079		$ 281,079	$ 281,079	$ -	$ 281,079
	Deductions:							
14	Customer deposits	$ 20,925	$ -		$ 20,925	$ 20,925	$ -	$ 20,925
15	Customer advances for construction	19	-		19	19	-	19
16	Accum. Deferred income taxes - Liberalized depreciation	495,161	(133,944)	8	361,217	358,831	2,386	361,217
17	Operating reserves (net of taxes)	653	(146)	9	508	508	-	508
18	Total deductions	$ 516,758	$ (134,090)		$ 382,669	$ 380,283	$ 2,386	$ 382,669
19	Total Rate Base	$ 1,363,781	$ 49,184		$ 1,412,965	$ 1,384,856	$ 28,109	$ 1,412,965
20	Pro forma return at present rates (PA Distribution)	$ 29,730	Dollars					
21		2.10%	Percent					
22	Pro forma return at proposed rates (PA Distribution)	$ 113,767	Dollars					
23		8.05%	Percent					

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 1
($000)

Adjustment of Electric Plant in Service

To adjust the budgeted gross plant in service to (1) eliminate the Asset Retirement Cost ("ARC") An asset retirement cost ("ARC") increases the carrying amount of a long-lived asset when a liability for an asset retirement obligation ("ARO") is recognized. The ARC is depreciated over the life of the asset. The ARC and related reserve are excluded from Rate Base, while the associated depreciation expense is excluded from the Income Statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18 Asset retirement obligations; (2) remove FERC Transmission Plant which is non-jurisdictional; (3) remove an allocated portion of Intangible Plant that supports FERC Transmission Plant; (4) remove an allocated portion of General Plant that supports FERC Transmission Plant; and (5) remove legacy meters as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Adjustments	Plant in Service	Cross Reference
		(1)	(2)	(3)
1	Budgeted Plant in Service at 4/30/2016		$ 2,935,437	Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2
	Normalizing adjustments:			
2	Eliminate ARC	$ (95,358)		Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2
3	Remove FERC Transmission Plant	(454,163)		Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2
4	Remove allocated portion of Intangible Plant associated with FERC Transmission Plant	(9,695)		Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2
5	Remove allocated portion of General Plant associated with FERC Transmission Plant	(43,570)		Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2
6	Remove legacy meters	(66,795)		Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2
7	Normalization adjustment		(669,581)	
8	Plant in Service at 4/30/2016, as adjusted		$ 2,265,856	Met-Ed Exhibit RAD-46, Attach. B, p. 1 and 2

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 2
($000)

Adjustment of Plant Held for Future Use

To adjust Plant Held for Future Use. As an alternative to rate base treatment, the Company is requesting the allowance of deferred carrying charges on any current or future investments in Plant Held for Future Use with definitive plans of utilization within a ten-year period. This is consistent with long-standing Commission policy.

Line No.		Amount (1)
1	Per budget Plant Held for Future Use at 4/30/2016	$ 596
	Normalizing adjustment:	
2	Eliminate Plant Held for Future Use	(596)
3	Plant Held for Future Use at 4/30/2016, as adjusted	$ -

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 3
($000)

Adjustment of Depreciation Reserves - Plant In Service

To adjust the budgeted plant in service depreciation reserves to (1) eliminate the Asset Retirement Cost ("ARC") reserves. An asset retirement cost ("ARC") increases the carrying amount of a long-lived asset when a liability for an asset retirement obligation ("ARO") is recognized. The ARC is depreciated over the life of the asset. The ARC and related reserve are excluded from Rate Base, while the associated depreciation expense is excluded from the Income Statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18 Asset retirement obligations; (2) remove FERC Transmission Plant reserves which are non-jurisdictional; (3) remove an allocated portion of Intangible Plant reserves that support FERC Transmission Plant; (4) remove an allocated portion of General Plant reserves that support FERC Transmission Plant; (5) and remove legacy meters as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Adjustments	Depreciation Reserves Plant in Service	Cross Reference
		(1)	(2)	(3)
1	Plant in Service depreciation reserves at 4/30/2016		$ 1,055,494	Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
	Normalizing adjustments:			
2	Eliminate ARC	$ (95,344)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
3	Remove FERC Transmission Plant	(155,934)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
4	Remove allocated portion of Intangible Plant associated with FERC Transmission Plant	(6,012)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
5	Remove allocated portion of General Plant associated with FERC Transmission Plant	(30,270)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
6	Remove legacy meters	(16,632)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
7	Normalization Adjustment		(304,192)	
8	Plant in Service depreciation reserves at 4/30/2016, as adjusted		$ 751,302	Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 4
($000)

Adjustment of Cash Working Capital

To recognize cash working capital at year-end level. This adjustment is supported by Ms. P. M. Larkin.

Line No.		Cash Working Capital (1)	Cash Working Capital (2)
1	Cash working capital per budget at 4/30/2016		$ -
	Normalizing adjustment:		
2	Cash working capital normalized to year-end (Exhibit PML-1)	$ 147,828	
3	Cash working capital per budget	-	
4	Normalization Adjustment		147,828
5	Cash working capital at 4/30/2016, as adjusted		$ 147,828

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 5
($000)

Adjustment of Material and Supplies Inventories

To recognize the Company's distribution portion of FE Service material and supplies ("M&S") inventory levels projected at 4/30/2016.

Line No.		M&S Inventories (1)	M&S Inventories (2)
1	M&S Inventory per budget at 4/30/2016		$ -
	Normalizing adjustment:		
2	Distribution component of projected FE Service M&S Inventory allocated to Met-Ed at 4/30/2016 (Exhibit RAD-13)	$ 14,493	
3	M&S Inventory per budget at 4/30/2016	-	
4	Normalization Adjustment		14,493
5	M&S inventory at 4/30/2016, as adjusted		$ 14,493

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 6
($000)

Adjustment of Deferred Storm Damage Expenses

To include in rate base the deferred storm damage balances for Winter Storm Nika, approved at Docket No. P-2014-2412229, Hurricane Sandy, approved at Docket No. P-2013-2351260, and distribution non-capital storm expenses that exceeded 125% of storm costs included in base rates between the period of February 25, 2011 through September 30, 2012 as a result of the FirstEnergy and Allegheny Merger approved at Docket Nos. A-2010-2176520 and A-2010-2176732, including but not limited to Hurricane Irene, the October 2011 snowstorm, and Tropical Storm Lee.

Line No.		Storms (1)	Storms (2)
1	Unamortized storm deferral expense per budget at 4/30/2016		$ -
2	Deferred Nika storm damage	$ 13,327	
3	Deferred Sandy storm damage	21,497	
4	Merger storm damage deferral	30,140	
5	Normalization Adjustment (Lines 2 + 3 + 4)		64,964
6	Storm Expense at 4/30/2016 as adjusted		$ 64,964

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 7
($000)

Adjustment to Include Legacy Meters in Regulatory Asset

To include legacy meters in a regulatory asset as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Legacy Meters (1)	Legacy Meters (2)
1	Net legacy meters in regulatory asset		$ -
2	Legacy meters per budget at 4/30/2016	$ 66,795	
3	Net estimated cost of removal and salvage	3,631	
4	Depreciation reserve per budget at 4/30/2016	(16,632)	
5	Net legacy meters normalizing adjustment (Lines 2 + 3 +4)		53,794
6	Net legacy meters in regulatory asset as adjusted at 4/30/2016		$ 53,794

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 8
($000)

Adjustment of Accumulated Deferred Income Taxes - Liberalized Depreciation

This adjustment adjusts the budgeted deferred tax balances for liberalized depreciation (excluding the impact of SFAS No. 109 deferrals) to (1) eliminate the deferred income taxes - liberalized depreciation balances associated with TMI-2; (2) eliminate deferred income taxes - liberalized depreciation associated with other generation; (3) eliminate other excludable items (capital leases); (4) eliminate remaining state deferred taxes - liberalized depreciation balances including the federal benefit of those taxes; and (5) eliminate an allocated portion of the remaining federal deferred income taxes - liberalized depreciation balance associated with FERC Transmission Plant.

Line No.		Adjustments (1)	Accum Reserve for Deferred Taxes - Liberalized Depreciation (2)
1	Deferred taxes per budget - liberalized depreciation at 4/30/2016		$ 495,161
	Normalizing adjustments:		
2	Eliminate deferred income taxes - liberalized depreciation associated with TMI-2 (federal and state)	$ 2,792	
3	Eliminate deferred income taxes - liberalized depreciation associated with other generation (federal and state)	(93)	
4	Eliminate other excludable items - capital leases (federal and state)	(17,014)	
5	Eliminate remaining state deferred taxes - liberalized depreciation including the federal benefit of those taxes	(15,959)	
6	Eliminate an allocated portion of the remaining federal deferred income taxes - liberalized depreciation associated with FERC Transmission Plant	(103,670)	
7	Normalization Adjustment		(133,944)
8	Deferred taxes - liberalized depreciation at 4/30/2016, as adjusted		$ 361,217

METROPOLITAN EDISON COMPANY

Normalization Adjustment No. 9
($000)

Adjustment of Operating Reserves

To adjust operating reserves (net of accumulated deferred income taxes) to eliminate an allocated portion associated with FERC Transmission operations.

Line No.		Amount
1	Operating reserves, net of taxes, per budget at 4/30/2016	$ 653
	Normalizing adjustment:	
2	Eliminate portion of operating reserves associated with FERC Transmission operations	(146)
3	Operating reserves, net of taxes at 4/30/2016, as adjusted	$ 508

METROPOLITAN EDISON COMPANY

Rate of Return at April 30, 2016
($000)

Line No.	Description	Exhibit SRS-24 Capital Amounts (1)	Capital Ratios (2)	Cost Rate (3)	Weighted Cost Rate (4) = (2) X (3)
1	Total long-term debt	$ 849,707	50.04%	5.21%	2.61%
2	Total preferred stock	-	0.00%	0.00%	0.00%
3	Total Common Equit	848,489	49.96%	10.90%	5.44%
4	Total Capitalization	$ 1,698,196	100.00%		8.05%

Metropolitan Edison Company
Statement of Operating Income, 12 Months Ending April 30, 2016, Normalized and Adjusted
to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Per Budget	Normalizations & Adjustments	Adj. No.	Budget as Adjusted	Normalized PaPUC Jurisdictional										
							Riders									
						Distribution	Price to Compare	Universal Service	Energy Efficiency	Smart Meters	Default Service Support	Solar	NUG	Storm	PaPUC Total Distribution
		(1)	(2)		(3)=(1)+(2)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13) = (8) + (4)
	Operating revenues														
1	Retail sales	$ 656,675	$ 25	1	$ 656,700	$ 250,689	$ 286,330	$ 28,732	$ 27,285	$ 15,657	$ 39,190	$ 3,066	$ 5,751	$ -	$ 266,346
2	STAS revenue	-	-	2	-	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	12,678	-		12,678	-	12,678	-	-	-	-	-	-	-	-
4	Other operating revenue	72,265	(55,404)	3	16,861	18,593	(1,732)	-	-	-	-	-	-	-	18,593
5	Total operating revenue	741,618	(55,379)		686,239	269,282	297,276	28,732	27,285	15,657	39,190	3,066	5,751	-	284,939
	Operating expenses														
6	Price to Compare	278,274	-		278,274	-	275,732	-	-	-	-	2,542	-	-	-
7	Distribution	56,647	(8,731)	4	47,916	38,389	-	-	-	-	9,527	-	-	-	38,389
8	Customer accounts	23,271	1,457	5	24,728	17,325	-	-	-	-	7,403	-	-	-	17,325
9	Customer service & info	40,721	44	6	40,765	18,847	-	21,732	-	-	186	-	-	-	18,847
10	Admin & gen expense	41,116	14,207	7	55,323	22,326	-	-	24,313	8,684	-	-	-	-	31,010
11	Depreciation - accrual	64,431	11,737	8	76,168	72,727	-	-	-	3,441	-	-	-	-	76,168
12	Amortization & Accretion	38,376	22,686	9	61,062	21,656	8,026	6,265	1,362	434	17,508	399	5,412	-	22,090
13	Taxes other than income	45,795	(940)	10	44,855	20,901	16,893	1,695	1,610	924	2,312	181	339	-	21,825
14	Operating expense before tax	588,631	40,461		629,092	212,172	300,651	29,692	27,285	13,483	36,936	3,122	5,751	-	225,655
15	Operating income before income tax	152,987	(95,840)		57,147	57,111	(3,375)	(960)	-	2,174	2,254	(56)	-	-	59,285
	Income taxes														
16	Federal income tax - current	39,423	(20,174)	11	19,249	19,239	(1,063)	(302)	-	684	710	(18)	-	-	19,923
17	State income tax - current	-	6,104	11	6,104	6,101	(337)	(96)	-	217	225	(6)	-	-	6,318
18	Deferred income tax - federal	6,297	(2,699)	12	3,598	2,763	-	-	-	835	-	-	-	-	3,598
19	Deferred income tax - state	-		12	-	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	(364)	81	13	(283)	(283)	-	-	-	-	-	-	-	-	(283)
21	Total tax expense	45,356	(16,688)		28,668	27,819	(1,400)	(398)	-	1,736	935	(23)	-	-	29,555
22	Total operating expenses	633,987	23,773		657,760	239,991	299,251	29,294	27,285	15,219	37,871	3,099	5,751	-	255,210
23	**Operating income**	$ 107,631	$ (79,152)		$ 28,479	$ 29,292	$ (1,975)	$ (562)	$ -	$ 438	$ 1,319	$ (33)	$ -	$ -	$ 29,730

Metropolitan Edison Company
Statement of Operating Income, 12 Months Ending April 30, 2016, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Distribution	Riders: Price to Compare	Riders: Universal Service	Riders: Energy Efficiency	Riders: Smart Meters	Riders: Default Service Support	Riders: Solar	Riders: NUG	Riders: Storm	PaPUC Total Distribution
		(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23) = (14) + (18)
	Operating revenues										
1	Retail sales	$ 149,328	$ -	$ -	$ -	$ 3,315	$ -	$ -	$ -	$ -	$ 152,643
2	STAS revenue	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	-	-	-	-	-	-	-	-	-	-
4	Other operating revenue	-	-	-	-	-	-	-	-	-	-
5	Total operating revenue	149,328	-	-	-	3,315	-	-	-	-	152,643
	Operating expenses										
6	Price to Compare	-	-	-	-	-	-	-	-	-	-
7	Distribution	-	-	-	-	-	-	-	-	-	-
8	Customer accounts	-	-	-	-	-	-	-	-	-	-
9	Customer service & info	-	-	-	-	-	-	-	-	-	-
10	Admin & gen expense	-	-	-	-	-	-	-	-	-	-
11	Depreciation - accrual	-	-	-	-	-	-	-	-	-	-
12	Amortization	-	-	-	-	-	-	-	-	-	-
13	Taxes other than income	8,810	-	-	-	196	-	-	-	-	9,006
14	Operating expense before tax	8,810	-	-	-	196	-	-	-	-	9,006
15	Operating income before income tax	140,517	-	-	-	3,120	-	-	-	-	143,637
	Income taxes										
16	Federal income tax - current	44,268	-	-	-	983	-	-	-	-	45,251
17	State income tax - current	14,038	-	-	-	312	-	-	-	-	14,349
18	Deferred income tax - federal	-	-	-	-	-	-	-	-	-	-
19	Deferred income tax - state	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	-	-	-	-	-	-	-	-	-	-
21	Total tax expense	58,306	-	-	-	1,295	-	-	-	-	59,600
22	Total operating expenses	67,116	-	-	-	1,490	-	-	-	-	68,606
23	**Operating income**	$ 82,212	$ -	$ -	$ -	$ 1,825	$ -	$ -	$ -	$ -	$ 84,037

Metropolitan Edison Company
Statement of operating Income, 12 Months Ending April 30, 2016, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Distribution	Riders: Price to Compare	Riders: Universal Service	Riders: Energy Efficiency	Riders: Smart Meters	Riders: Default Service Support	Riders: Solar	Riders: NUG	Riders: Storm	PaPUC Total Distribution
		(24) = (4) + (14)	(25)	(26)	(27)	(28) = (8) + (18)	(29)	(30)	(31)	(32)	(33) = (24) + (28)
	Operating revenues										
1	Retail sales	$ 400,017	$ 286,330	$ 28,732	$ 27,285	$ 18,972	$ 39,190	$ 3,066	$ 5,751	$ -	$ 418,989
2	STAS revenue	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	-	12,678	-	-	-	-	-	-	-	-
4	Other operating revenue	18,593	(1,732)	-	-	-	-	-	-	-	18,593
5	Total operating revenue	418,610	297,276	28,732	27,285	18,972	39,190	3,066	5,751	-	437,582
		-				-				-	
	Operating expenses	-				-				-	
6	Price to Compare	-	275,732	-	-	-	-	2,542	-	-	-
7	Distribution	38,389	-	-	-	-	9,527	-	-	-	38,389
8	Customer accounts	17,325	-	-	-	-	7,403	-	-	-	17,325
9	Customer service & info	18,847	-	21,732	-	-	186	-	-	-	18,847
10	Admin & gen expense	22,326	-	-	24,313	8,684	-	-	-	-	31,010
11	Depreciation - accrual	72,727	-	-	-	3,441	-	-	-	-	76,168
12	Amortization	21,656	8,026	6,265	1,362	434	17,508	399	5,412	-	22,090
13	Taxes other than income	29,712	16,893	1,695	1,610	1,120	2,312	181	339	-	30,831
14	Operating expense before tax	220,982	300,651	29,692	27,285	13,679	36,936	3,122	5,751	-	234,661
		-				-				-	
15	Operating income before tax	197,628	(3,375)	(960)	-	5,294	2,254	(56)	-	-	202,922
		-				-				-	
	Income taxes	-				-				-	
16	Federal income tax - current	63,506	(1,063)	(302)	-	1,667	710	(18)	-	-	65,173
17	State income tax - current	20,138	(337)	(96)	-	529	225	(6)	-	-	20,667
18	Deferred income tax - federal	2,763	-	-	-	835	-	-	-	-	3,598
19	Deferred income tax - state	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	(283)	-	-	-	-	-	-	-	-	(283)
21	Total tax expense	86,124	(1,400)	(398)	-	3,031	935	(23)	-	-	89,155
		-				-				-	
22	Total operating expenses	307,107	299,251	29,294	27,285	16,709	37,871	3,099	5,751	-	323,816
		-									
23	**Operating income**	$ 111,503	$ (1,975)	$ (562)	$ -	$ 2,263	$ 1,319	$ (33)	$ -	$ -	$ 113,767
24	**Rate Base**	$ 1,384,856	-	$ -	$ -	$ 28,109	$ -	$ -	$ -	$ -	1,412,965
25	**Rate of Return overall**	8.05%				8.05%					8.05%
26	**Return on Equity**	10.90%				10.90%					10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Distribution
$000

Line No.	Description	Budget as Adjusted	Revenue Adjustment Required	Allowable Revenue
		(1)	(2)	(3)
	Operating revenues			
1	Retail sales	$ 250,689	$ 149,328	$ 400,017
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	18,593	-	18,593
5	Total operating revenue	269,282	149,328	418,610
	Operating expenses			
6	PTC	-	-	-
7	Distribution	38,389	-	38,389
8	Customer accounts	17,325	-	17,325
9	Customer service & info	18,847	-	18,847
10	Admin & gen expense	22,326	-	22,326
11	Depreciation - accrual	72,727	-	72,727
12	Amortization	21,656	-	21,656
13	Taxes other than income	20,901	8,810	29,712
14	Operating expense before tax	212,172	8,810	220,982
15	Operating income before tax	57,111	140,517	197,628
	Income taxes			
16	Federal income tax - current	19,239	44,268	63,506
17	State income tax - current	6,101	14,038	20,138
18	Deferred income tax - federal	2,763	-	2,763
19	Deferred income tax - state	-	-	-
20	Investment tax credit	(283)	-	(283)
21	Total tax expense	27,819	58,306	86,124
22	Total operating expenses	239,991	67,116	307,107
23	**Operating Income**	$ 29,292	$ 82,212	$ 111,503
24	**Rate Base**	1,384,856		1,384,856
25	**Rate of Return overall**	2.12%		8.05%
26	**Return on Equity**	-1.0%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Smart Meter
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 15,657	$ 3,315	$ 18,972
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	15,657	3,315	18,972
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	-	-	-
10	Admin & gen expense	8,684	-	8,684
11	Depreciation - accrual	3,441	-	3,441
12	Amortization	434	-	434
13	Taxes other than income	924	196	1,120
14	Operating expense before tax	13,483	196	13,679
15	Operating income before tax	2,174	3,120	5,294
	Income taxes			
16	Federal income tax - current	684	983	1,667
17	State income tax - current	217	312	529
18	Deferred income tax - federal	835	-	835
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	1,736	1,295	3,031
22	Total operating expenses	15,219	1,490	16,709
23	**Operating income**	$ 438	$ 1,825	$ 2,263
24	**Rate Base**	28,109		28,109
25	**Rate of Return overall**	1.56%		8.05%
26	**Return on Equity**	-2.10%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Total Distribution
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 266,346	$ 152,643	$ 418,989
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	18,593	-	18,593
5	Total operating revenue	284,939	152,643	437,582
	Operating expenses			
6	PTC	-	-	-
7	Distribution	38,389	-	38,389
8	Customer accounts	17,325	-	17,325
9	Customer service & info	18,847	-	18,847
10	Admin & gen expense	31,010	-	31,010
11	Depreciation - accrual	76,168	-	76,168
12	Amortization	22,090	-	22,090
13	Taxes other than income	21,825	9,006	30,831
14	Operating expense before tax	225,655	9,006	234,661
15	Operating income before tax	59,285	143,637	202,922
	Income taxes			
16	Federal income tax - current	19,923	45,251	65,173
17	State income tax - current	6,318	14,349	20,667
18	Deferred income tax - federal	3,598	-	3,598
19	Deferred income tax - state	-	-	-
20	Investment tax credit	(283)	-	(283)
21	Total tax expense	29,555	59,600	89,155
22	Total operating expenses	255,210	68,606	323,816
23	**Operating income**	$ 29,730	$ 84,037	$ 113,767
24	**Rate Base**	1,412,965		1,412,965
25	**Rate of Return overall**	2.10%		8.05%
26	**Return on Equity**	-1.0%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Universal Service Cost Rider
$000

Line No.	Description	Budget as Adjusted	Revenue Adjustment Required	Allowable Revenue
		(1)	(2)	(3)
	Operating revenues			
1	Retail sales	$ 28,732	$ -	$ 28,732
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	28,732	-	28,732
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	21,732	-	21,732
10	Admin & gen expense	-	-	-
11	Depreciation - accrual	-	-	-
12	Amortization	6,265	-	6,265
13	Taxes other than income	1,695	-	1,695
14	Operating expense before tax	29,692	-	29,692
15	Operating income before tax	(960)	-	(960)
	Income taxes			
16	Federal income tax - current	(302)	-	(302)
17	State income tax - current	(96)	-	(96)
18	Deferred income tax - federal	-	-	-
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	(398)	-	(398)
22	Total operating expenses	29,294	-	29,294
23	**Operating income**	(562)	-	(562)

Metropolitan Edison Company
Summary of Revenue Requirements
Storm Damage Rider
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ -	$ -	$ -
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	-	-	-
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	-	-	-
10	Admin & gen expense	-	-	-
11	Depreciation - accrual	-	-	-
12	Amortization	-	-	-
13	Taxes other than income	-	-	-
14	Operating expense before tax	-	-	-
15	Operating income before tax	-	-	-
	Income taxes	-		
16	Federal income tax - current	-	-	-
17	State income tax - current	-	-	-
18	Deferred income tax - federal	-	-	-
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	-	-	-
22	Total operating expenses	-	-	-
23	**Operating income**	$ -	$ -	$ -

Metropolitan Edison Company
Normalization Adjustment No. 1
$000

Adjustment of Base Operating Revenues

To adjust base operating revenues for (1) changes in the number of customers, (2) to roll in State Tax Adjustment Surcharge ("STAS") revenues into base rates, (3) to adjust for energy efficiency and behind the meter generation, (4) to adjust for other revenues and (5) to eliminate unbilled revenues. The adjustment for unbilled revenues is supported by Mr. R. A. D'Angelo. Adjustments (1) through (4) are supported by Mr. K. M. Siedt.

Line No.	Description	Amount (1)	Amount (2)
1	Base revenues per budget for the 12 months ending 4/30/16		$ 656,675
	Normalizing adjustments:		
2	Customers - increase to yr end level	$ 502	
	Specific adjustments		
3	Roll-in of STAS	-	
4	Adjust for Energy Efficiency and Behind the Meter Generation	(457)	
5	Adjust for Other Revenues	41	
6	Eliminate unbilled revenues	(61)	
7	Total	$ (477)	
8	Normalizing adjustment (Lines 2+7)		25
9	Base revenues per budget for the 12 months ending 4/30/2016, as adjusted		$ 656,700

Metropolitan Edison Company
Normalization Adjustment No. 2
$000

Adjustment of State Tax Adjustment Surcharge Revenues

To remove state tax adjustment surcharge ("STAS") revenues. Normalized STAS revenues are being rolled into base rates.

Line No.	Description	Amount (1)
1	STAS revenue per budget for the 12 months ending 4/30/2016	$ -
2	Eliminate per budget STAS	-
3	Other operating revenue per budget for the 12 months ending 4/30/2016, as adjusted	$ -

Metropolitan Edison Company
Normalization Adjustment No. 3
$000

Adjustment of Other Operating Revenues

To adjust other operating revenue to eliminate non-jurisdictional transmission revenues.

Line No.	Description	Amount (1)
1	Other operating revenue per budget for the 12 months ending 4/30/2016	$ 72,265
2	Eliminate non-jurisdictional transmission revenues	(55,404)
3	Other operating revenue per budget for the 12 months ending 4/30/2016, as adjusted	$ 16,861

Metropolitan Edison Company
Normalization Adjustment No. 4
$000

Adjustment of Distribution Expense

To adjust distribution payroll expense to reflect year end wage and employee levels, to adjust service company distribution payroll expense to reflect year end wage and employee levels, eliminate non-jurisdictional transmission expense and to include the distribution portion of the amortization of gains or losses to reacquired debt. The plant and labor allocation factors used in this normalization adjustment are supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	Amount (2)
1	Distribution expense per budget for the 12 months ending 4/30/2016		$ 56,647
2	Distribution payroll expense adjustment to reflect year end employee levels, and ongoing wage and salary rates (Supporting Schedule No. 1, Line 12, Column 1)	$ 263	
3	Service Company Distribution payroll expense adjustment allocated to Met-Ed to reflect year end employee levels, and ongoing wage and salary rates (Supporting Schedule No. 1, Line 21, Column 1)	66	
4	Eliminate non-jurisdictional transmission expense	(9,140)	
5	Amortization of (gain) or loss on reacquired debt	$ 104	
6	Allocation ratio based on distribution plant	77.70%	
7	Distribution portion of (gain) or loss	$ 81	
8	Total normalizing adjustment (Lines 2 + 3 + 4 + 7)		(8,731)
9	Distribution expense per budget for the 12 months ending 4/30/2016, as adjusted		$ 47,916

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 4
($000)

Adjustment to Payroll Expense to Reflect Year End Employee Levels and Wage Rates

Line No.	Description		Amount (1)	Amount (2)
1	Total payroll per budget for the 12 months ending 4/30/2016 (Exhibit RAD-27)			$ 61,177
	Bargaining			
2	Straight time per budget for the 12 months ending 4/30/2016		$ 36,777	
3	Straight time 2.5% increase effective 5/1/2016 (Line 2 x 2.5%)		919	
	Non-Bargaining			
4	Straight time per budget for May 1, 2015 through February 28, 2016		13,205	
5	Straight time 3% increase effective 3/1/2016 (Line 4 x 3%)		396	
6	Total company payroll adjustment (Line 3 + Line 5)			1,316
7	O&M allocation %		39.67%	
8	O&M payroll as adjusted (Line 6 X Line 7)		$ 522	
9	Total Payroll adjustment (Line 1 + Line 6)			$ 62,493
	Allocation of payroll adjustment:			
10	Price to Compare	0.00%	$ -	
11	Transmission	8.91%	47	
12	Distribution	50.40%	263	
13	Customer accounts	17.72%	92	
14	Customer service	8.42%	44	
15	Administrative and general	14.55%	76	
16	Total	100%	$ 522	
	Service Company (Exhibit RAD-25)			
17	Straight time per budget for May 1, 2015 through February 28, 2016		$ 11,216	
18	Straight time 3% increase effective 3/1/2016 (Line 17 x 3%)		$ 336	
	Allocation of Service Company payroll adjustment (Exhibit RAD-25):			
19	Price to Compare	0.00%	$ -	
20	Transmission	7.20%	24	
21	Distribution	19.52%	66	
22	Customer Accounting and Information	29.33%	99	
23	Administrative and general	43.94%	148	
24	Total	100%	$ 336	

Metropolitan Edison Company
Normalization Adjustment No. 5
$000

Adjustment of Customer Accounts Expense

To adjust customer account expense to reflect year end wage and employee levels, service company year end wage and employee levels, increased costs associated with added customers, and interest on customer deposits.

Line No.	Description	Amount (1)	Amount (2)
1	Customer Account expense per budget for the 12 months ending 4/30/2016		$ 23,271
2	Customer Account payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates (Normalizing Adjustment No. 4, Supporting Schedule No. 1, Line 13, Column 1)	$ 92	
3	Service Company customer account payroll expense adjustment allocated to Met-Ed to reflect year end employee levels and ongoing wage & salary rates (Normalizing Adjustment No. 4, Supporting Schedule No. 1, Line 22, Column 1)	99	
4	Increased O&M costs associated with increased number of customers in normalized revenue levels (Supporting Schedule 1, Line 10)	10	
5	Interest on customer deposits (Supporting Schedule 2, Line 3)	1,256	
6	Total normalizing adjustment (Lines 2 + 3 + 4 + 5)		1,457
7	Customer Account expense per budget for the 12 months ending 4/30/2016, as adjusted		$ 24,728

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 5
($000)

Adjustment of Other O&M Costs Associated with Serving New Customers

In association with the additional revenues from added customers reflected in Adjustment No. 1, there is also a cost associated with serving those customers. The Commission has previously recognized this and approved an adjustment to customer accounts expense for this increased cost. This cost is estimated by determining the ratio of non-payroll customer account expense to distribution revenues from customers and applying this ratio to the additional revenue received from increased customers. The distribution revenues are supported by Mr. K. M. Siedt.

Line No.	Description	Amount (1)
	Customer Account Expense Excluding Labor and Uncollectible	
1	Customer Account expense per budget for the 12 months ending 4/30/2016	$ 23,271
2	Less: uncollectible expense	(12,136)
3	Less: Labor expense	(5,879)
4	Customer Account expense excluding labor and uncollectible expense	$ 5,256
	Total Base Revenue	
5	Distribution revenues per budget	$ 250,602
6	Late payment charges per budget	3,229
7	Total	$ 253,831
8	Ratio of customer account expense to distribution revenue (Line 4 / Line 7)	2.07%
9	Revenue from added customers (Adjustment No. 1, Line 2)	$ 502
10	Additional expense from added customers (Line 8 X Line 9)	$ 10

Metropolitan Edison Company
Supporting Schedule No. 2 to Normalizing Adjustment No. 5
($000)

Adjustment to Allow for Interest Expense on Customer Deposits

Customer deposits are included in rate base as a deduction, since these are funds supplied by customers to the company. Interest paid to customers on these deposits correspondingly has been recognized by the Commission as a expense when setting rates.

Line No.	Description	Amount (1)
1	Customer deposits included in rate base (Exhibit RAD-1 Column 1, Line 14)	$ 20,925
2	Interest rate on deposits	6%
3	Interest expense on customer deposits	$ 1,256

Metropolitan Edison Company
Normalization Adjustment No. 6
$000

Adjustment of Customer Service and Information Expense

To adjust customer service and information expense to reflect year end wage and employee levels.

Line No.	Description	Amount (1)	Amount (2)
1	Customer Service expense per budget for the 12 months ending 4/30/2016		$ 40,721
2	Customer Service payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates, (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 14, Column 1)	$ 44	
3	Total normalizing adjustment		44
4	Customer Service expense per budget for the 12 months ending 4/30/2016, as adjusted		$ 40,765

Metropolitan Edison Company
Normalization Adjustment No. 7
$000

Adjustment of Administrative and General Expense

To adjust Administrative and General expenses to reflect year end wage and employee levels, service company year end wage and employee levels, OPEB expense at the service cost level, pension expense to the ten year cash level, employee benefits expenses at year end personnel and wage levels, the elimination of non-jurisdictional administrative and general expenses, normalization of rate case expenses, eliminate legacy meters from the budget, and include costs to update computer system to allow accelerated (3 day) switching from one supplier to another. Hillary Stewart supports the non-jurisdictional expense allocation factor.

Line No.	Description	Amount (1)	Amount (2)
1	Administrative & general expense per budget for the 12 months ending 4/30/2016		$ 41,116
2	Administrative & general expenses related to EE&C	$ (24,313)	
3	Administrative & general expenses related to Smart Meters	(8,684)	
4	Adjustment to administrative & general expenses	(32,997)	
5	Net administrative & general expenses related to distribution	8,119	
6	Administrative & general payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates, (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 15, Column 1)	$ 76	
7	Service Company Administrative & general payroll expense adjustment allocated to Met-Ed to reflect year end employee levels and ongoing wage & salary rates (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 23, Column 1)	148	
8	Adjust OPEB expense to service cost level (Normalization Adjustment No. 7, Supporting Schedule No. 1, Line 12, Col. 1)	2,814	
9	Adjust pension expense to ten year cash level (Supporting Schedule No. 2, Line 18, Col. 3)	14,046	
10	Adjust employee benefit costs (Supporting Schedule No. 3, Line 8, Column 3	305	
11	Subtotal of adjustments (Lines 6 + 7 + 8 + 9 + 10)		17,389
12	Administrative and general expense, adjusted	$ 25,508	
13	Non-jurisdictional expense allocation factor	10.43%	
14	Non-jurisdictional administrative and general expense		(2,660)
15	Rate case expenses to be incurred during current rate proceeding (Exhibit RAD-23)	$ 495	
16	Recovery period - years	2	
17	Annual amount (Line 15 / Line 16)	$ 248	
18	Less rate case expenses in budget	(750)	
19	Adjusted total		$ (502)
20	Less legacy meters from budget		(330)
21	Increase in O&M costs for accelerated (3 day) switching for customers moving to a new supplier (Exhibit RAD-64)		311
22	Total normalizing adjustment (Lines 11 + 14 + 19 + 20 + 21)		14,207
23	Administrative and general expense per budget for the 12 months ending 4/30/2016, as adjusted		$ 55,323

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 7
$000

Adjustment for OPEB Expense

Budgeted OPEB expense consists of the current service cost, adjustments to prior years' service costs, and the financing component. This schedule adjusts the total budgeted expense amounts to the service cost. The service cost represents the actuarial present value of benefit liabilities accrued under the plan benefit formula for services rendered during the test year. Inclusion of the service cost in rates provides for recovery of the current cost of benefits earned by plan participants. Any excess or shortfall related to the expected return on plan assets are not included because their inclusion would artificially reduce or increase total costs and result in the recovery of more or less than the actual normal cost of service. The adjustment for OPEB expense to the current service cost amount was adopted by the Commission at Docket Nos. R-00061366 and R-00061367.

Line No.	Description	O&M (1)	Capital (2)	Total (3)
1	O&M - Capital allocation ratios	39.67%	60.33%	100.00%
2	Company OPEB expense included in budget	$ (1,962)	$ (2,984)	$ (4,946)
3	FirstEnergy Service Corp. OPEB expense	$ (11,066)	$ (16,830)	$ (27,896)
4	Allocation ratio	5.54%	5.54%	5.54%
5	Allocated FirstEnergy Service Corp. OPEB expense included in budget (Line 3 X Line 4)	$ (613)	$ (932)	$ (1,545)
6	Total OPEB expense included in budget (Line 2 + Line 5)	$ (2,575)	$ (3,916)	$ (6,491)
7	Service cost for company OPEB expense	$ 222	$ 337	$ 559
8	Service cost for FirstEnergy Service Corp. OPEB expense	$ 303	$ 461	$ 764
9	Allocation ratio	5.54%	5.54%	5.54%
10	Allocated FirstEnergy Service Corp. service cost (Line 8 X Line 9)	$ 17	$ 25	$ 42
11	Total OPEB service cost (Lines 7 + 10)	$ 239	$ 362	$ 601
12	Adjustment to set OPEB expense at ongoing service cost level (Lines 11 - 6)	$ 2,814	$ 4,278	$ 7,092

Metropolitan Edison Company
Supporting Schedule No. 2 to Normalizing Adjustment No. 7
$000

Adjustment for Pension Expense

To adjust budget pension expense to a ten year historical average level of actual cash contributions under the methodology that was adopted by the Commission at Docket Number R-00061366 and R-00061367.

Line No.	Description	Amount (1) Total	(2) O&M %	(3) O&M
	Company Cash Contributions			
1	2004 Cash Pension Contribution	$ 38,823	56.52%	$ 21,943
2	2005 Cash Pension Contribution	35,912	56.52%	20,297
3	2007 Cash Pension Contribution	11,012	55.42%	6,103
4	2009 Cash Pension Contribution	123,521	50.49%	62,366
5	2011 Cash Pension Contribution	35,000	45.09%	15,782
6	Total Company Cash Pension Contributions	$ 244,268		$ 126,490
	FirstEnergy Service Company Cash Contributions			
7	2004 Pension Contribution	$ 91,633		
8	2004 Company Allocation Factor	8.91%		
9	2004 Service Company Pension Contribution allocated to the Company	$ 8,165	56.52%	$ 4,615
10	2007 Pension Contribution	$ 27,468		
11	2007 Company Allocation Factor	11.29%		
12	2007 Service Company Pension Contribution allocated to the Company	$ 3,101	55.42%	1,719
13	Total FirstEnergy Service Company Cash Pension Contributions allocated to the Company (Line 9 + Line 12)	$ 11,266		$ 6,333
14	Total Pension cash contributions (Line 6 + Line 13)	$ 255,534		$ 132,824
15	Average	10		10
16	Pension expense cash contribution, amortized over 10 years	$ 25,553		$ 13,282
17	O&M Pension Expense included in budget			(763)
18	Adjustment to Pension Expense (Line 16 - Line 17)			$ 14,046

Metropolitan Edison Company
Supporting Schedule No. 3 to Normalizing Adjustment No. 7
$000

Adjustment to Employee Benefit Expense to Reflect Year End Employee Levels and Ongoing Wage Rates

Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 8 increases the O&M payroll expense. Associated with that increase are employee benefits charged to Administrative and General expense. This adjustment computes the added benefit costs on a normalized basis.

Employee benefits applicable to operating expenses:

Line No.		Effective Rate (a)	Payroll Adjustment		Benefit Adjustment
		(1)	(2)		(3) = (1) X (2)
1	Workers compensation	0.700%	$ 522	(b)	$ 4
2	Pension costs	39.928%	$ 522	(b)	208
3	OPEB costs	0.913%	$ 522	(b)	5
4	Life insurance	0.149%	$ 522	(b)	1
5	Medical insurance	9.464%	$ 522	(b)	49
6	Savings Plan	4.616%	$ 522	(b)	24
7	Other	2.602%	$ 522	(b)	14
8	Total increase due to payroll adjustment				$ 305

(a) Summary of effective employee benefit rates based on total payroll for the 12 months ending 4/30/16

	Total Amount	Total Payroll	Effective Rate
Workers compensation (Exhibit RAD-27)	$ 428	$ 61,177	0.700%
Pension costs - normalized basis	24,427	61,177	39.928%
OPEB costs - service cost	559	61,177	0.913%
Life insurance (Exhibit RAD-27)	91	61,177	0.149%
Medical insurance (Exhibit RAD-27)	5,790	61,177	9.464%
Savings Plan (Exhibit RAD-27)	2,824	61,177	4.616%
Other (Exhibit RAD-27)	1,592	61,177	2.602%

(b) Adjustment No. 4, Supporting Schedule No. 1, Line 8.

Metropolitan Edison Company
Normalization Adjustment No. 8
$000

Adjustment of Depreciation Expense

To adjust budgeted depreciation expense to reflect average remaining life rates on adjusted rate base, to eliminate non-jurisdictional expense, and to adjust cost of removal/ salvage expense to a five year average amount, according to prior commission practice and the adjustment of legacy meters. The plant allocation factor used in this normalization adjustment are supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	(2)	(3)	(4)
1	Depreciation expense per budget for the 12 months ending 4/30/2016				$ 64,431
2	Cost of removal/salvage expense per budget for the 12 months ending 4/30/2016 (Exhibit RAD-30)		$ 4,509		
3	Depreciation accrual per budget (Line 1 - Line 2)		$ 59,922		
4	Jurisdictional depreciation expense accrual on adjusted rate base at average remaining life rates (Exhibit RAD-53, page 2)		52,881		
5	Adjustment for average remaining life accrual for jurisdictional plant (Line 4 - Line 3)			$ (7,041)	
6	Cost of removal/salvage expense per budget for the 12 months ending 4/30/16 (Exhibit RAD-30)		$ 4,509		
	Cost of removal and salvage (Exhibit RAD-30)				
7	4/1/2009 - 3/31/2010	$ 17,539			
8	4/1/2010 - 3/31/2011	7,101			
9	4/1/2011 - 3/31/2012	17,511			
10	4/1/2012 - 3/31/2013	28,248			
11	4/1/2013 - 3/31/2014	10,222			
12	Total	$ 80,621			
13	Five year average (Line 12 / 5)		$ 16,124		
14	Allocation ratio based on jurisdictional plant		77.70%		
15	Jurisdictional cost of removal/salvage expense to a jurisdictional five year average (Line 13 X Line 14)		12,529		
16	Adjustment of jurisdictional cost of removal/salvage expense to a jurisdictional five year average (Line 15 - Line 6)			8,020	
17	Adjustment for amortization of legacy meters (Adj. 8, Sched. 1, Line 7)			10,759	
18	Total normalizing adjustment (Lines 5 + 16 + 17)				11,737
19	Depreciation expense per budget for the 12 months ending 4/30/2016, as adjusted				$ 76,168

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 8
$000

Adjustment for Amortization for legacy meters

To amortize recovery of legacy meters to fully recover all legacy meter costs over 5 years.

Line No.	Description	Amount (1)	Amount (2)
1	Legacy meters per budget for the 12 months ending 4/30/2016	$ 66,795	
2	Depreciation reserve per budget for the 12 months ending 4/30/2016	16,632	
3	Net legacy meters per budget for the 12 months ending 4/30/2016	$ 50,163	
4	Net estimated cost of removal and salvage	3,631	
5	Net legacy meters	$ 53,794	
6	Annual amortization over a 5 year amortization period		$ 10,759

Metropolitan Edison Company
Normalization Adjustment No. 9
$000

Adjustment of Amortization Expense

To include the amortization of deferred storm damage balances for Winter Storm Nika, approved at Docket No. P-2014-2412229, Hurricane Sandy, approved at Docket No. P-2013-2351260, and distribution non-capital storm expenses that exceeded 125% of storm costs included in base rates between the period of February 25, 2011 through September 30, 2012 as a result of the FirstEnergy and Allegheny Merger approved at Docket Nos. A-2010-2176520 and A-2010-2176732, including but not limited to Hurricane Irene, the October 2011 snowstorm, and Tropical Storm Lee. In addition, rate case expenses, legacy meters, and accretion expenses are removed from the budget.

Line No.	Description	Amount (1)	Amount (2)	Amount (3)
1	Amortization expense per budget for the 12 months ending 4/30/2016			$ 38,376
2	Deferred Nika storm damage	$ 13,327		
3	Deferred Sandy storm damage	21,497		
4	Merger storm deferral	30,140		
5	Total deferred storms (Lines 2 + 3 + 4)	$ 64,964		
6	Amortized over 3 years	3		
7	Annual Amortization		$ 21,655	
8	Remove rate case expenses		750	
9	Remove legacy meters from budget		330	
10	Remove accretion expense		(49)	
11	Normalization adjustment (Lines 7 + 8 + 9 + 10)			22,686
12	Amortization expense per budget for the 12 months ending 4/30/2016, as adjusted			$ 61,062

Metropolitan Edison Company
Normalization Adjustment No. 10
$000

Adjustment of Taxes Other Than Income

To adjust gross receipts tax expense to reflect normalized sales revenues, to adjust payroll tax expenses for normalized payroll and employee expenses. The non-jurisdictional allocation factor is supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	Amount (2)	Amount (3)
1	Taxes Other Than Income per budget for the 12 months ending 4/30/2016			$ 45,795
2	Federal and State payroll taxes in budget (Exhibit RAD-32)	$ 4,694		
3	Non-jurisdictional percent	10.43%		
4	Eliminate non-jurisdictional payroll taxes		$ (490)	
5	Capital Stock Tax included in budget (Exhibit RAD-32)	$ 149		
6	PURTA tax in budget (Exhibit RAD-32)	1,976		
7	Real Estate tax in budget (Exhibit RAD-32)	131		
8	Total Other taxes	$ 2,256		
9	Non-jurisdictional percent	22.30%		
10	Eliminate non-jurisdictional taxes		(503)	
	Gross Receipts Tax			
11	Normalized sales revenues (Exhibit RAD-2, page 1, Col. 3)	$ 656,700		
12	Gross receipts tax @ 5.9%	38,745		
13	Gross receipts tax included in budget (Exhibit RAD-32)	38,732		
14	Adjustment for gross receipts tax at normalized revenue level (Line 12 - Line 13)		13	
15	Adjustment for payroll taxes on normalized payroll (Supporting Schedule No. 1, Line 8)		40	
16	Total normalizing adjustment (Lines 4+10+14+15)			(940)
17	Taxes other than income per budget for the 12 months ending 4/30/2016, as adjusted			$ 44,855

Metropolitan Edison Company
Supporting Schedule No.1 to Normalizing Adjustment No. 10
$000

Adjustment to Taxes Other Than Income to reflect changes in payroll taxes.

Normalization adjustments have been made to normalize O&M payroll expense. Associated with those payroll normalizations are changes in FICA tax amounts.

Line No.	Description	Amount (1)
1	Total payroll per budget for the 12 months ending 4/30/2016 (Normalization Adjustment No. 4, Schedule 1, Line 1, Col 2)	$ 61,177
2	Total payroll tax included in budget (Exhibit RAD-32)	4,694
3	Effective payroll tax rate (Line 2 / Line 1)	7.673%
4	Total payroll as adjusted (Normalization Adjustment No. 4, Schedule 1, Line 9, Col. 2)	$ 62,493
5	Payroll tax on normalized payroll (Line 3 x Line 4)	$ 4,795
6	Total Company payroll tax adjustment (Line 5 - Line 2)	$ 101
7	O&M Allocation percentage	39.67%
8	Adjustment for payroll tax (Line 6 x Line 7)	$ 40

Metropolitan Edison Company
Normalization Adjustment No. 11
$000

Computation of Federal & State Income Taxes - Normalized

Line No.	Description	Total Company Calculated Taxes (1)	Distribution Calculated Taxes (3)	PTC Calculated Taxes (2)	Universal Service Calculated Taxes (4)	Energy Efficiency Calculated Taxes (5)	Smart Meter Rider Calculated Taxes (6)	DSS Calculated Taxes (7)	Solar Calculated Taxes (8)	NUG Charge Calculated Taxes (9)	Storm Rider Calculated Taxes (10)
1	Total operating revenue	$ 686,239	$ 269,282	$ 297,276	$ 28,732	$ 27,285	$ 15,657	$ 39,190	$ 3,066	$ 5,751	$ -
2	Less: Total O& M Expense	447,006	96,887	275,732	21,732	24,313	8,684	17,116	2,542	$ -	$ -
3	Depreciation - accrual	63,640	60,199	-	-	-	3,441	-	-	-	-
4	Average net salvage	12,529	12,529	-	-	-	-	-	-	-	-
5	Amortization	61,062	21,656	8,026	6,265	1,362	434	17,508	399	5,412	-
6	Taxes other than income taxes	44,855	20,901	16,893	1,695	1,610	924	2,312	181	339	-
7	Total deductions	$ 629,092	$ 212,172	$ 300,651	$ 29,692	$ 27,285	$ 13,483	$ 36,936	$ 3,122	$ 5,751	$ -
8	Net operating income before income taxes	$ 57,147	$ 57,111	$ (3,375)	$ (960)	$ -	$ 2,174	$ 2,254	$ (56)	$ -	$ -
9	Less: Interest Charges (A)	36,822	36,089	-	-	-	733	-	-	-	-
10	Net income before income taxes	$ 20,325	$ 21,021	$ (3,375)	$ (960)	$ -	$ 1,441	$ 2,254	$ (56)	$ -	$ -
	Adjustments to taxable income:										
11	Book Average net salvage	12,529	12,529	-	-	-	-	-	-	-	-
12	Adj. of book depreciation to tax basis (B)	$ 20,282	$ 19,552	$ -	$ -	$ -	$ 730	$ -	$ -	$ -	$ -
13	Tax cost of removal/salvage	(6,080)	(6,080)	-	-	-	-	-	-	-	-
14	Adjust cash pension	14,046	14,046	-	-	-	-	-	-	-	-
15	Net adjustment	40,777	40,047	-	-	-	730	-	-	-	-
16	Income subject to state income tax	61,102	61,068	(3,375)	(960)	-	2,171	2,254	(56)	-	-
17	State income tax @ 9.99%	$ 6,104	$ 6,101	$ (337)	$ (96)	$ -	$ 217	$ 225	$ (6)	$ -	$ -
18	Taxes as budgeted	-	-	-	-	-	-	-	-	-	-
19	Adjustment to state income tax	$ 6,104	$ 6,101	$ (337)	$ (96)	$ -	$ 217	$ 225	$ (6)	$ -	$ -
20	Income subject to federal income tax	$ 54,998	$ 54,967	$ (3,038)	$ (864)	$ -	$ 1,955	$ 2,029	$ (50)	$ -	$ -
21	Federal income tax @ 35%	$ 19,249	$ 19,239	$ (1,063)	$ (302)	$ -	$ 684	$ 710	$ (18)	$ -	$ -
22	Taxes as budgeted	39,423	39,423	-	-	-	-	-	-	-	-
23	Adjustment to federal income tax	$ (20,174)	$ (20,184)	$ (1,063)	$ (302)	$ -	$ 684	$ 710	$ (18)	$ -	$ -
	(A) Computation of Interest charges										
	Total rate base	$ 1,412,965	$ 1,384,856	$ -	$ -	$ -	$ 28,109	$ -	$ -	$ -	$ -
	Debt ratio	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%
	Cost of debt	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%
	Interest expense	$ 36,822	$ 36,089	$ -	$ -	$ -	$ 733	$ -	$ -	$ -	$ -
	(B) Adjustment of book depreciation to tax basis:										
	Tax depreciation	43,357	40,646	-	-	-	2,711	-	-	-	-
	Book depreciation	63,640	60,199	-	-	-	3,441	-	-	-	-
	Depreciation adjustment	(20,282)	(19,552)	-	-	-	(730)	-	-	-	-

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalization Adjustment No. 11
$000

Computation of Federal & State Income Taxes - Normalized

To (1) split the tax depreciation into cost of removal, smart meter, and distribution components, and (2) calculate the jurisdictional allocation.

Line No.	Description	Amount (1)	(2)	(3)
1	Tax depreciation expense per budget (Exhibit RAD-33)	$ 62,848		
2	Cost of removal / salvage in tax depreciation	7,825	77.70%	$ 6,080
3	Smart meter tax depreciation	2,711	100.00%	2,711
4	Distribution tax depreciation	$ 52,312	77.70%	40,646
5	Total tax Depreciation			$ 43,357

Metropolitan Edison Company
Normalization Adjustment No. 12
$000

Adjustment of Provision for Deferred Income Taxes

This adjustment to the Provision for Deferred Income Taxes reflects the adjustment of Federal deferrals to reflect year-end plant. All state deferred taxes associated with liberalized depreciation have been eliminated.

Line No.	Description	Provision for Deferred Taxes - Net	
		Federal	State
		(1)	(2)
1	Deferred taxes per budget, 12 months ending 4/30/2016	$ 6,297	$ -
2	Deferred taxes - liberalized depreciation (Exhibit RAD-41, page 19)	4,630	-
3	Jurisdictional allocation factor	77.70%	77.70%
4	Jurisdictional deferred taxes - liberalized depreciation (Line 2 X Line 3)	3,598	-
5	Adjustment to deferred tax expense (Line 4 - Line 1)	(2,699)	-
6	Deferred tax expense per budget for the 12 months ending 4/30/2016, as adjusted	$ 3,598	$ -

Metropolitan Edison Company
Normalization Adjustment No. 13
$000

Adjustment of Investment Tax Credit

This adjustment eliminates the non-jurisdictional portion of investment tax credit adjustments.

Line No.	Description	Amount (1)	Amount (2)
1	Investment tax credit adjustments per budget, 12 months ending 4/30/2016		$ (364)
2	Jurisdictional allocation factor	77.70%	
3	Jurisdictional investment tax credit	$ (283)	
4	Adjustment to investment tax credit expense (Line 3 - Line 1)		81
5	Adjustment to investment tax credit expense per budget for the 12 months ending 4/30/2016, as adjusted		$ (283)

METROPOLITAN EDISON COMPANY
Rate Base At Original Cost
Normalized To Year-End Conditions at March 31, 2015
($000)

Line No.	Description	Per Budget	Adjustments and Normalizations	Adj No.	Total	Pa Juridictional Normalized Rate Base: Distribution	Pa Juridictional Normalized Rate Base: Smart Meter Costs	Pa Juridictional Normalized Rate Base: PA Jurisdictional Total
		(1)	(2)		(3)	(4)	(5)	(6) = (4) + (5)
	Electric Plant:							
1	Plant in service	$ 2,818,193	$ (645,740)	1	$ 2,172,453	$ 2,161,696	$ 10,757	$ 2,172,453
2	Plant held for future use	596	(596)	2	-	-	-	-
3	Construction work in progress - pollution control and safety	-	-		-	-	-	-
		-	-		-	-	-	-
4	Total electric plant	$ 2,818,789	$ (646,336)		$ 2,172,453	$ 2,161,696	$ 10,757	$ 2,172,453
	Depreciation & Amortization Reserve:							
5	Plant in service	$ 1,001,528	$ (295,475)	3	$ 706,053	$ 705,566	$ 487	$ 706,053
6	Plant held for future use	-	-		-	-	-	-
7	Total depreciation & amortization reserve	$ 1,001,528	$ (295,475)		$ 706,053	$ 705,566	$ 487	$ 706,053
8	Net Electric Plant	$ 1,817,261	$ (350,861)		$ 1,466,400	$ 1,456,130	$ 10,270	$ 1,466,400
	Additions:							
9	Cash working capital	$ -	$ 147,828	4	$ 147,828	$ 147,828	$ -	$ 147,828
10	M&S inventories	-	14,493	5	14,493	14,493	-	14,493
11	Deferred storm damage	-	64,964	6	64,964	64,964		64,964
12	Legacy meters	-	55,698	7	55,698	55,698	-	55,698
13	Total additions	$ -	$ 282,983		$ 282,983	$ 282,983	$ -	$ 282,983
	Deductions:							
14	Customer deposits	$ 20,925	$ -		$ 20,925	$ 20,925	$ -	$ 20,925
15	Customer advances for construction	19	-		19	19	-	19
16	Accum. Deferred income taxes - Liberalized depreciation	489,924	(132,620)	8	357,304	356,703	601	357,304
17	Operating reserves (net of taxes)	653	(146)	9	508	508	-	508
18	Total deductions	$ 511,521	$ (132,766)		$ 378,756	$ 378,155	$ 601	$ 378,756
19	Total Rate Base	$ 1,305,740	$ 64,888		$ 1,370,628	$ 1,360,959	$ 9,669	$ 1,370,628
20	Pro forma return at present rates (PA Distribution)	$ 28,742	Dollars					
21		2.10%	Percent					
22	Pro forma return at proposed rates (PA Distribution)	$ 110,373	Dollars					
23		8.05%	Percent					

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 1
($000)

Adjustment of Electric Plant in Service

To adjust the budgeted gross plant in service to (1) eliminate the Asset Retirement Cost ("ARC"). An asset retirement cost ("ARC") increases the carrying amount of a long-lived asset when a liability for an asset retirement obligation ("ARO") is recognized. The ARC is depreciated over the life of the asset. The ARC and related reserve are excluded from Rate Base, while the associated depreciation expense is excluded from the Income Statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18 Asset retirement obligations; (2) remove FERC Transmission Plant which is non-jurisdictional; (3) remove an allocated portion of Intangible Plant that supports FERC Transmission Plant; (4) remove an allocated portion of General Plant that supports FERC Transmission Plant; and (5) remove legacy meters as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Adjustments	Plant in Service	Cross Reference
		(1)	(2)	(3)
1	Budgeted Plant in Service at March 31, 2015		$ 2,818,193	Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2
	Normalizing adjustments:			
2	Eliminate ARC	$ (95,358)		Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2
3	Remove FERC Transmission Plant	(433,209)		Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2
4	Remove allocated portion of Intangible Plant associated with FERC Transmission Plant	(6,968)		Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2
5	Remove allocated portion of General Plant associated with FERC Transmission Plant	(43,410)		Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2
6	Remove legacy meters	(66,795)		Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2
7	Normalization adjustment		(645,740)	
8	Plant in Service at 3/31/2015, as adjusted		$ 2,172,453	Met-Ed Exhibit RAD-47, Attach. B, p. 1 and 2

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 2
($000)

Adjustment of Plant Held for Future Use

To adjust Plant Held for Future Use. As an alternative to rate base treatment, the Company is requesting the allowance of deferred carrying charges on any current or future investments in Plant Held for Future Use with definitive plans of utilization within a ten-year period. This is consistent with long-standing Commission policy.

Line No.		Amount (1)
1	Per budget Plant Held for Future Use at 3/31/2015	$ 596
2	Eliminate Plant Held for Future Use	(596)
3	Plant Held for Future Use at 3/31/2015, as adjusted	$ -

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 3
($000)

Adjustment of Depreciation Reserves - Plant In Service

To adjust the budgeted plant in service depreciation reserves to (1) eliminate the Asset Retirement Cost ("ARC") reserves. An asset retirement cost ("ARC") increases the carrying amount of a long-lived asset when a liability for an asset retirement obligation ("ARO") is recognized. The ARC is depreciated over the life of the asset. The ARC and related reserve are excluded from Rate Base, while the associated depreciation expense is excluded from the Income Statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18 Asset retirement obligations; (2) remove FERC Transmission Plant reserves which are non-jurisdictional; (3) remove an allocated portion of Intangible Plant reserves that support FERC Transmission Plant; (4) remove an allocated portion of General Plant reserves that support FERC Transmission Plant; (5) and remove legacy meters as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Adjustments	Depreciation Reserves Plant in Service	Cross Reference
		(1)	(2)	(3)
1	Plant in Service depreciation reserves at 3/31/2015		$ 1,001,528	Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
	Normalizing adjustments:			
2	Eliminate ARC	$ (95,343)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
3	Remove FERC Transmission Plant	(151,084)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
4	Remove allocated portion of Intangible Plant associated with FERC Transmission Plant	(5,489)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
5	Remove allocated portion of General Plant associated with FERCTransmission Plant	(28,832)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
6	Legacy meters	(14,728)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
7	Normalization Adjustment		(295,475)	
8	Plant in Service depreciation reserves at 3/31/2015, as adjusted		$ 706,053	Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 4
($000)

Adjustment of Cash Working Capital

To recognize cash working capital at year-end level. This adjustment is supported by Ms. P. M. Larkin.

Line No.		Cash Working Capital (1)	Cash Working Capital (2)
1	Cash working capital per budget at 3/31/2015		$ -
	Normalizing adjustment:		
2	Cash working capital normalized to year-end (Exhibit PML-1)	$ 147,828	
3	Cash working capital per budget	-	
4	Normalization Adjustment		147,828
5	Cash working capital at 3/31/2015, as adjusted		$ 147,828

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 5
($000)

Adjustment of Material and Supplies Inventories

To recognize the Company's distribution portion of FE Service material and supplies ("M&S") inventory levels projected at 3/31/2015

Line No.		M&S Inventories (1)	M&S Inventories (2)
1	M&S Inventory per budget at 3/31/2015		$ -
	Normalizing adjustment:		
2	Distribution component of projected FE Service M&S Inventory allocated to Met-Ed at 3/31/2015 (Exhibit RAD-13)	$ 14,493	
3	M&S Inventory per budget at 3/31/2015	-	
4	Normalization Adjustment		14,493
5	M&S inventory at 3/31/2015, as adjusted		$ 14,493

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 6
($000)

Adjustment of Deferred Storm Damage Expenses

To include in rate base the deferred storm damage balances for Winter Storm Nika, approved at Docket No. P-2014-2412229, Hurricane Sandy, approved at Docket No. P-2013-2351260, and distribution non-capital storm expenses that exceeded 125% of storm costs included in base rates between the period of February 25, 2011 through September 30, 2012 as a result of the FirstEnergy and Allegheny Merger approved at Docket Nos. A-2010-2176520 and A-2010-2176732, including but not limited to Hurricane Irene, the October 2011 snowstorm, and Tropical Storm Lee.

Line No.		Storms	
		(1)	(2)
1	Unamortized storm deferral expense per budget at 3/31/2015		$ -
2	Deferred Nika storm damage	13,327	
3	Deferred Sandy storm damage	21,497	
4	Merger storm damage deferral	30,140	
5	Normalization less storm per budget Adjustment (Lines 2 + 3 + 4)		64,964
6	Storm Expense at 3/31/2015 as adjusted		$ 64,964

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 7
($000)

Adjustment to Include Legacy Meters in Regulatory Asset

To include legacy meters in a regulatory asset as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Legacy Meters (1)	Legacy Meters (2)
1	Net legacy meters in regulatory asset		$ -
2	Legacy meters per budget at 3/31/2015	$ 66,795	
3	Net estimated cost of removal and salvage	3,631	
4	Depreciation reserve per budget at 3/31/2015	(14,728)	
5	Net legacy meters normalizing adjustment (Lines 2 + 3 + 4)		55,698
6	Net legacy meters in regulatory asset as adjusted at 3/31/2015		$ 55,698

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 8
($000)

Adjustment of Accumulated Deferred Income Taxes - Liberalized Depreciation

This adjustment adjusts the budgeted deferred tax balances for liberalized depreciation (excluding the impact of SFAS No. 109 deferrals) to (1) eliminate the deferred income taxes - liberalized depreciation balances associated with TMI-2; (2) eliminate deferred income taxes - liberalized depreciation associated with other generation; (3) eliminate other excludable items (capital leases); (4) eliminate remaining state deferred taxes - liberalized depreciation balances including the federal benefit of those taxes; and (5) eliminate an allocated portion of the remaining federal deferred income taxes - liberalized depreciation balance associated with FERC Transmission Plant.

Line No.		Adjustments (1)	Accum Reserve for Deferred Taxes - Liberalized Depreciation (2)
1	Deferred taxes per budget - liberalized depreciation at 3/31/2015		$ 489,924
	Normalizing adjustments:		
2	Eliminate deferred income taxes - liberalized depreciation associated with TMI-2 (federal and state)	$ 2,840	
3	Eliminate deferred income taxes - liberalized depreciation associated with other generation (federal and state)	(95)	
4	Eliminate other excludable items - capital leases (federal and state)	(17,014)	
5	Eliminate remaining state deferred taxes - liberalized depreciation including the federal benefit of those taxes	(15,804)	
6	Eliminate an allocated portion of the remaining federal deferred income taxes - liberalized depreciation associated with FERC Transmission Plant	(102,547)	
7	Normalization Adjustment		(132,620)
8	Deferred taxes - liberalized depreciation at 3/31/2015, as adjusted		$ 357,304

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 9
($000)

Adjustment of Operating Reserves

To adjust operating reserves (net of accumulated deferred income taxes) to eliminate an allocated portion associated with FERC Transmission operations.

Line No.		Amount
1	Operating reserves, net of taxes, per budget at 3/31/2015	$ 653
2	Eliminate portion of operating reserves associated with FERC Transmission operations	(146)
3	Operating reserves, net of taxes at 3/31/2015, as adjusted	$ 508

METROPOLITAN EDISON COMPANY

Rate of Return at March 31, 2015
($000)

Line No.	Description	Exhibit SRS-24 Capital Amounts (1)	Capital Ratios (2)	Cost Rate (3)	Weighted Cost Rate (4) = (2) X (3)
1	Total long-term debt	$ 849,707	50.04%	5.21%	2.61%
2	Total preferred stock	-	0.00%	0.00%	0.00%
3	Total Common Equity	848,489	49.96%	10.90%	5.44%
4	Total Capitalization	$ 1,698,196	100.00%		8.05%

Metropolitan Edison Company
Statement of Operating Income, 12 Months Ending March 31, 2015, Normalized and Adjusted
to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Per Budget	Normalizations & Adjustments	Adj. No.	Budget as Adjusted	Distribution	Normalized PaPUC Jurisdictional: Riders: Price to Compare	Universal Service	Energy Efficiency	Smart Meters	Default Service Support	Solar	NUG	Storm	PaPUC Total Distribution
		(1)	(2)		(3)=(1)+(2)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13) = (4) + (8)
	Operating revenues														
1	Retail sales	$ 675,063	$ (32)	1	$ 675,031	$ 249,195	$ 313,070	$ 21,501	$ 25,419	$ 13,760	$ 39,274	$ 3,060	$ 9,752	$ -	$ 262,955
2	STAS revenue	-	-	2	-	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	21,076	-		21,076	-	20,983	-	93	-	-	-	-	-	-
4	Other operating revenue	72,494	(55,476)	3	17,017	18,593	(1,576)	-	-	-	-	-	-	-	18,593
5	Total operating revenue	768,633	(55,508)		713,124	267,788	332,477	21,501	25,512	13,760	39,274	3,060	9,752	-	281,548
	Operating expenses														
6	Price to Compare	322,385	-		322,385	-	320,256	-	-	-	-	2,129	-	-	-
7	Distribution	53,448	(8,202)	4	45,246	34,545	-		-	-	10,700	-	-	-	34,545
8	Customer accounts	25,286	1,528	5	26,814	18,705	-	-	-	-	8,109	-	-	-	18,705
9	Customer service & info	44,208	50	6	44,258	18,894	-	25,062	-	-	302	-	-	-	18,894
10	Admin & gen expense	37,806	18,217	7	56,023	19,902	-	-	24,389	11,732	-	-	-	-	31,634
11	Depreciation - accrual	59,573	11,245	8	70,818	69,469	-	-	-	1,349	-	-	-	-	70,818
12	Amortization & Accretion	13,023	22,344	9	35,367	21,655	(5,713)	(4,312)	(377)	(1,066)	15,233	770	9,177	-	20,589
13	Taxes other than income	46,882	(959)	10	45,923	20,798	18,471	1,269	1,500	812	2,317	181	575	-	21,610
14	Operating expense before tax	602,612	44,223		646,835	203,970	333,014	22,019	25,512	12,827	36,662	3,080	9,752	-	216,796
15	Operating income before incom	166,021	(99,732)		66,289	63,818	(537)	(518)	-	934	2,612	(19)	-	-	64,752
	Income taxes														
16	Federal income tax - current	25,303	(306)	11	24,997	24,079	(169)	(163)	-	434	823	(6)	-	-	24,513
17	State income tax - current	-	7,927	11	7,927	7,636	(54)	(52)	-	138	261	(2)	-	-	7,773
18	Deferred income tax - federal	27,321	(17,684)	12	9,637	9,426	-	-	-	211	-	-	-	-	9,637
19	Deferred income tax - state	-	-	12	-	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	(364)	(283)	13	(647)	(647)	-	-	-	-	-	-	-	-	(647)
21	Total tax expense	52,260	(10,346)		41,914	40,493	(223)	(215)	-	783	1,084	(8)	-	-	41,276
22	Total operating expenses	654,871	33,877		688,749	244,463	332,791	21,804	25,512	13,609	37,745	3,072	9,752	-	258,072
23	**Operating income**	$ 113,762	$ (89,386)		$ 24,375	$ 23,325	$ (314)	$ (303)	$ -	$ 151	$ 1,528	$ (11)	$ -	$ -	$ 23,476

Metropolitan Edison Company
Statement of Operating Income, 12 Months Ending March 31, 2015, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Distribution	Riders: Price to Compare	Riders: Universal Service	Riders: Energy Efficiency	Riders: Smart Meters	Riders: Default Service Support	Riders: Solar	Riders: NUG	Riders: Storm	PaPUC Total Distribution
		(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23) = (14) + (18)
	Operating revenues										
1	Retail sales	$ 156,698	$ -	$ -	$ -	$ 1,140	$ -	$ -	$ -	$ -	$ 157,838
2	STAS revenue	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	-	-	-	-	-	-	-	-	-	-
4	Other operating revenue	-	-	-	-	-	-	-	-	-	-
5	Total operating revenue	156,698	-	-	-	1,140	-	-	-	-	157,838
	Operating expenses										
6	Price to Compare	-	-	-	-	-	-	-	-	-	-
7	Distribution	-	-	-	-	-	-	-	-	-	-
8	Customer accounts	-	-	-	-	-	-	-	-	-	-
9	Customer service & info	-	-	-	-	-	-	-	-	-	-
10	Admin & gen expense	-	-	-	-	-	-	-	-	-	-
11	Depreciation - accrual	-	-	-	-	-	-	-	-	-	-
12	Amortization	-	-	-	-	-	-	-	-	-	-
13	Taxes other than income	9,245	-	-	-	67	-	-	-	-	9,312
14	Operating expense before tax	9,245	-	-	-	67	-	-	-	-	9,312
15	Operating income before incom	147,453	-	-	-	1,072	-	-	-	-	148,525
	Income taxes										
16	Federal income tax - current	46,453	-	-	-	338	-	-	-	-	46,791
17	State income tax - current	14,731	-	-	-	107	-	-	-	-	14,838
18	Deferred income tax - federal	-	-	-	-	-	-	-	-	-	-
19	Deferred income tax - state	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	-	-	-	-	-	-	-	-	-	-
21	Total tax expense	61,183	-	-	-	445	-	-	-	-	61,628
22	Total operating expenses	70,428	-	-	-	512	-	-	-	-	70,941
23	**Operating income**	$ 86,269	$ -	$ -	$ -	$ 627	$ -	$ -	$ -	$ -	$ 86,897

Metropolitan Edison Company
Statement of operating Income, 12 Months Ending March 31, 2015, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Distribution	Riders: Price to Compare	Riders: Universal Service	Riders: Energy Efficiency	Riders: Smart Meters	Riders: Default Service Support	Riders: Solar	Riders: NUG	Riders: Storm	PaPUC Total Distribution
		(24) = (4) + (14)	(25)	(26)	(27)	(28) = (8) + 18)	(29)	(30)	(31)	(32)	(33)
	Operating revenues										
1	Retail sales	$ 405,893	$ 313,070	$ 21,501	$ 25,419	$ 14,900	$ 39,274	$ 3,060	$ 9,752	$ -	$ 420,793
2	STAS revenue	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	-	20,983	-	93	-	-	-	-	-	-
4	Other operating revenue	18,593	(1,576)	-	-	-	-	-	-	-	18,593
5	Total operating revenue	424,486	332,477	21,501	25,512	14,900	39,274	3,060	9,752	-	439,386
						-					
	Operating expenses					-					
6	Price to Compare	-	320,256	-	-	-	-	2,129	-	-	-
7	Distribution	34,545	-	-	-	-	10,700	-	-	-	34,545
8	Customer accounts	18,705	-	-	-	-	8,109	-	-	-	18,705
9	Customer service & info	18,894	-	25,062	-	-	302	-	-	-	18,894
10	Admin & gen expense	19,902	-	-	24,389	11,732	-	-	-	-	31,634
11	Depreciation - accrual	69,469	-	-	-	1,349	-	-	-	-	70,818
12	Amortization	21,655	(5,713)	(4,312)	(377)	(1,066)	15,233	770	9,177	-	20,589
13	Taxes other than income	30,043	18,471	1,269	1,500	879	2,317	181	575	-	30,923
14	Operating expense before tax	213,215	333,014	22,019	25,512	12,894	36,662	3,080	9,752	-	226,109
15	Operating income before tax	211,271	(537)	(518)	-	2,006	2,612	(19)	-	-	213,277
	Income taxes										
16	Federal income tax - current	70,531	(169)	(163)	-	772	823	(6)	-	-	71,303
17	State income tax - current	22,366	(54)	(52)	-	245	261	(2)	-	-	22,611
18	Deferred income tax - federal	9,426	-	-	-	211	-	-	-	-	9,637
19	Deferred income tax - state	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	(647)	-	-	-	-	-	-	-	-	(647)
21	Total tax expense	101,677	(223)	(215)	-	1,228	1,084	(8)	-	-	102,904
		-				-				-	
22	Total operating expenses	314,892	332,791	21,804	25,512	14,122	37,745	3,072	9,752	-	$ 329,013
		-									
23	**Operating income**	$ 109,594	$ (314)	$ (303)	$ -	$ 779	$ 1,528	$ (11)	$ -	$ -	$ 110,373
24	**Rate Base**	$ 1,360,959	-	$ -	$ -	$ 9,669	$ -	$ -	$ -	$ -	1,370,628
25	**Rate of Return overall**	8.05%				8.05%					8.05%
26	**Return on Equity**	10.90%				10.90%					10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Distribution
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 249,195	$ 156,698	$ 405,893
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	18,593	-	18,593
5	Total operating revenue	267,788	156,698	424,486
	Operating expenses			
6	PTC	-	-	-
7	Distribution	34,545	-	34,545
8	Customer accounts	18,705	-	18,705
9	Customer service & info	18,894	-	18,894
10	Admin & gen expense	19,902	-	19,902
11	Depreciation - accrual	69,469	-	69,469
12	Amortization	21,655	-	21,655
13	Taxes other than income	20,798	9,245	30,043
14	Operating expense before tax	203,970	9,245	213,215
15	Operating income before tax	63,818	147,453	211,271
	Income taxes			
16	Federal income tax - current	24,079	46,453	70,531
17	State income tax - current	7,636	14,731	22,366
18	Deferred income tax - federal	9,426	-	9,426
19	Deferred income tax - state	-	-	-
20	Investment tax credit	(647)	-	(647)
21	Total tax expense	40,493	61,183	101,677
22	Total operating expenses	244,463	70,428	314,892
23	**Operating income**	$ 23,325	$ 86,269	$ 109,594
24	**Rate Base**	1,360,959		1,360,959
25	**Rate of Return overall**	1.71%		8.05%
26	**Return on Equity**	-1.79%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Smart Meter
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 13,760	$ 1,140	$ 14,900
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	13,760	1,140	14,900
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	-	-	-
10	Admin & gen expense	11,732	-	11,732
11	Depreciation - accrual	1,349	-	1,349
12	Amortization	(1,066)	-	(1,066)
13	Taxes other than income	812	67	879
14	Operating expense before tax	12,827	67	12,894
15	Operating income before tax	934	1,072	2,006
	Income taxes			
16	Federal income tax - current	434	338	772
17	State income tax - current	138	107	245
18	Deferred income tax - federal	211	-	211
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	783	445	1,228
22	Total operating expenses	13,609	512	14,122
23	**Operating income**	$ 151	$ 627	$ 779
24	**Rate Base**	9,669		9,669
25	**Rate of Return overall**	1.56%		8.05%
26	**Return on Equity**	-2.09%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Total Distribution
$000

Line No.	Description	Budget as Adjusted	Revenue Adjustment Required	Allowable Revenue
		(1)	(2)	(3)
	Operating revenues			
1	Retail sales	$ 262,955	$ 157,838	$ 420,793
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	18,593	-	18,593
5	Total operating revenue	281,548	157,838	439,386
	Operating expenses			
6	PTC	-	-	-
7	Distribution	34,545	-	34,545
8	Customer accounts	18,705	-	18,705
9	Customer service & info	18,894	-	18,894
10	Admin & gen expense	31,634	-	31,634
11	Depreciation - accrual	70,818	-	70,818
12	Amortization	20,589	-	20,589
13	Taxes other than income	21,610	9,312	30,923
14	Operating expense before tax	216,796	9,312	226,109
15	Operating income before tax	64,752	148,525	213,277
	Income taxes			
16	Federal income tax - current	24,513	46,791	71,303
17	State income tax - current	7,773	14,838	22,611
18	Deferred income tax - federal	9,637	-	9,637
19	Deferred income tax - state	-	-	-
20	Investment tax credit	(647)	-	(647)
21	Total tax expense	41,276	61,628	102,904
22	Total operating expenses	258,072	70,941	329,013
23	**Operating income**	$ 23,476	$ 86,897	$ 110,373
24	**Rate Base**	1,370,628		1,370,628
25	**Rate of Return overall**	1.71%		8.05%
26	**Return on Equity**	-1.79%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Universal Service Cost Rider
$000

Line No.	Description	Budget as Adjusted	Revenue Adjustment Required	Allowable Revenue
		(1)	(2)	(3)
	Operating revenues			
1	Retail sales	$ 21,501	$ -	$ 21,501
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	21,501	-	21,501
	Operating expenses	-		
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	25,062	-	25,062
10	Admin & gen expense	-	-	-
11	Depreciation - accrual	-	-	-
12	Amortization	(4,312)	-	(4,312)
13	Taxes other than income	1,269	-	1,269
14	Operating expense before tax	22,019	-	22,019
15	Operating income before tax	(518)	-	(518)
	Income taxes			
16	Federal income tax - current	(163)	-	(163)
17	State income tax - current	(52)	-	(52)
18	Deferred income tax - federal	-	-	-
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	(215)	-	(215)
22	Total operating expenses	21,804	-	21,804
23	**Operating income**	$ (303)	$ -	$ (303)

Metropolitan Edison Company
Summary of Revenue Requirements
Storm Damage Rider
$000

Line No.	Description	Budget as Adjusted	Revenue Adjustment Required	Allowable Revenue
		(1)	(2)	(3)
	Operating revenues			
1	Retail sales	$ -	$ -	$ -
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	-	-	-
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	-	-	-
10	Admin & gen expense	-	-	-
11	Depreciation - accrual	-	-	-
12	Amortization	-	-	-
13	Taxes other than income	-	-	-
14	Operating expense before tax	-	-	-
15	Operating income before tax	-	-	-
	Income taxes			
16	Federal income tax - current	-	-	-
17	State income tax - current	-	-	-
18	Deferred income tax - federal	-	-	-
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	-	-	-
22	Total operating expenses	-	-	-
23	**Operating income**	$ -		$ -

Metropolitan Edison Company
Normalization Adjustment No. 1
$000

Adjustment of Base Operating Revenues

To adjust base operating revenues (1) for changes in the number of customers, (2) to roll in State Tax Adjustment Surcharge ("STAS") revenues into base rates, (3) to adjust for energy efficiency and behind the meter generation, (4) to adjust for other revenues and (5) to eliminate unbilled revenues. The adjustment for unbilled revenues is supported by Mr. R. A. D'Angelo. Adjustments (1) through (4) are supported by Mr. K. M. Siedt.

Line No.	Description	Amount (1)	Amount (2)
1	Base revenues per budget for the 12 months ending 3/31/15		$ 675,063
	Normalizing adjustments:		
2	Customers - increase to yr end level	$ 394	
	Specific adjustments		
3	Roll-in of STAS	-	
4	Adjust for Energy Efficiency and Behind the Meter Generation	(2,232)	
5	Adjust for Other Revenues	42	
6	Eliminate unbilled revenues	1,763	
7	Total	$ (427)	
8	Normalizing adjustment (Lines 2+7)		(32)
9	Base revenues per budget for the 12 months ending 3/31/2015, as adjusted		$ 675,031

Metropolitan Edison Company
Normalization Adjustment No. 2
$000

Adjustment of State Tax Adjustment Surcharge Revenues

To remove state tax adjustment surcharge ("STAS") revenues. Normalized STAS revenues are being rolled into base rates.

Line No.	Description	Amount (1)
1	STAS revenue per budget for the 12 months ending 3/31/2015	$ -
2	Eliminate per budget STAS	-
3	Other operating revenue per budget for the 12 months ending 3/31/2015, as adjusted	$ -

Metropolitan Edison Company
Normalization Adjustment No. 3
$000

Adjustment of Other Operating Revenues

To adjust other operating revenue to eliminate non-jurisdictional transmission revenues.

Line No.	Description	Amount (1)
1	Other operating revenue per budget for the 12 months ending 3/31/2015	$ 72,494
2	Eliminate non-jurisdictional transmission revenues	(55,476)
3	Other operating revenue per budget for the 12 months ending 3/31/2015, as adjusted	$ 17,017

Metropolitan Edison Company
Normalization Adjustment No. 4
$000

Adjustment of Distribution Expense

To adjust distribution payroll expense to reflect year end wage and employee levels, to adjust service company distribution payroll expense to reflect year end wage and employee levels, eliminate non-jurisdictional transmission expense and to include the distribution portion of the amortization of gains or losses to reacquired debt. The plant and labor allocation factors used in this normalization adjustment are supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	Amount (2)
1	Distribution expense per budget for the 12 months ending 3/31/2015		$ 53,448
2	Distribution payroll expense adjustment to reflect year end employee levels, and ongoing wage and salary rates, (Supporting Schedule No. 1, Line 14, Column 1)	$ 298	
3	Service Company Distribution payroll expense adjustment allocated to Met-Ed to reflect year end employee levels, and ongoing wage and salary rates (Supporting Schedule No. 1, Line 26, Column 1)	100	
4	Eliminate non-jurisdictional transmission expense	(8,911)	
5	Amortization of (gain) or loss on reacquired debt	$ 400	
6	Allocation ratio based on distribution plant	77.70%	
7	Distribution portion of (gain) or loss	$ 311	
8	Total normalizing adjustment (Lines 2 + 3 + 4 + 7)		(8,202)
9	Distribution expense per budget for the 12 months ending 3/31/2015, as adjusted		$ 45,246

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 4
($000)

Adjustment to Payroll Expense to Reflect Year End Employee Levels and Wage Rates

Line No.	Description		Amount (1)	Amount (2)
1	Total payroll per budget for the 12 months ending 3/31/2015 (Exhibit RAD-27)			$ 59,762
	Bargaining			
2	Straight time per budget for the 12 months ending 3/31/2015		$ 35,333	
3	Straight time 2.5% increase effective 5/1/2015 (Line 2 x 2.5%)		883	
	Non-Bargaining			
4	Straight time per budget for April 1, 2014 through August 31, 2014		6,252	
5	Straight time 3% increase effective 9/1/2014 (Line 4 x 3%)		188	
6	Straight time per budget for April 1, 2014 through February 28, 2015		14,030	
7	Straight time 3% increase effective 3/1/2015 (Line 6 x 3%)		421	
8	Total company payroll adjustment (Line 3 + Line 5 + Line 7)			1,492
9	O&M allocation %		39.67%	
10	O&M payroll adjustment (Line 8 X Line 9)		$ 592	
11	Total Payroll as adjusted (Line 1 + Line 8)			$ 61,254
	Allocation of payroll adjustment:			
12	Price to Compare	0.00%	$ -	
13	Transmission	8.91%	53	
14	Distribution	50.40%	298	
15	Customer accounts	17.72%	105	
16	Customer service	8.42%	50	
17	Administrative and general	14.55%	86	
18	Total	100%	$ 592	
	Service Company (Exhibit RAD-25)			
19	Straight time per budget for April 1, 2014 through August 31, 2014		$ 5,766	
20	Straight time 3% increase effective 9/1/2014 (Line 19 x 3%)		173	
21	Straight time per budget for April 1, 2014 through February 28, 2015		12,859	
22	Straight time 3% increase effective 3/1/2015 (Line 21 x 3%)		386	
23	Total Service Company payroll adjustment (Lines 20 + 22)		$ 559	
	Allocation of Service Company payroll adjustment (Exhibit RAD-25):			
24	Price to Compare	0.00%	$ -	
25	Transmission	6.74%	38	
26	Distribution	17.91%	100	
27	Customer accounting and Information	28.31%	158	
28	Administrative and general	47.04%	263	
29	Total	100%	$ 559	

Metropolitan Edison Company
Normalization Adjustment No. 5
$000

Adjustment of Customer Accounts Expense

To adjust customer account expense to reflect year end wage and employee levels, service company year end wage and employee levels, increased costs associated with added customers, and interest on customer deposits.

Line No.	Description	Amount (1)	Amount (2)
1	Customer Account expense per budget for the 12 months ending 3/31/2015		$ 25,286
2	Customer Account payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates (Normalizing Adjustment No. 4, Supporting Schedule No. 1, Line 15, Column 1)	$ 105	
3	Service Company customer account payroll expense adjustment allocated to Met-Ed to reflect year end employee levels and ongoing wage & salary rates (Normalizing Adjustment No. 4, Supporting Schedule No. 1, Line 27, Column 1)	158	
4	Increased O&M costs associated with increased number of customers in normalized revenue levels (Supporting Schedule 1, Line 10)	9	
5	Interest on customer deposits (Supporting Schedule 2, Line 3)	1,256	
6	Total normalizing adjustment (Lines 2 + 3 + 4 + 5)		1,528
7	Customer Account expense per budget for the 12 months ending 3/31/2015, as adjusted		$ 26,814

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 5
($000)

Adjustment of Other O&M Costs Associated with Serving New Customers

In association with the additional revenues from added customers reflected in Adjustment No. 1, there is also a cost associated with serving those customers. The Commission has previously recognized this and approved an adjustment to customer accounts expense for this increased cost. This cost is estimated by determining the ratio of non-payroll customer account expense to distribution revenues from customers and applying this ratio to the additional revenue received from increased customers. The distribution revenues are supported by Mr. K. M. Siedt.

Line No.	Description	Amount
		(1)
	Customer Account Expense Excluding Labor and Uncollectible	
1	Customer Account expense per budget for the 12 months ending 3/31/2015	$ 25,286
2	Less: uncollectible expense	(13,864)
3	Less: Labor expense	(5,879)
4	Customer Account expense excluding labor and uncollectible expense	$ 5,543
	Total Base Revenue	
5	Distribution revenues per budget	$ 250,990
6	Late payment charges per budget	3,229
7	Total	$ 254,219
8	Ratio of customer account expense to distribution revenue (Line 4 / Line 7)	2.18%
9	Revenue from added customers (Adjustment No. 1, Line 2)	$ 394
10	Additional expense from added customers (Line 8 X Line 9)	$ 9

Metropolitan Edison Company
Supporting Schedule No.2 to Normalizing Adjustment No. 5
($000)

Adjustment to Allow for Interest Expense on Customer Deposits

Customer deposits are included in rate base as a deduction, since these are funds supplied by customers to the company. Interest paid to customers on these deposits correspondingly has been recognized by the Commission as a expense when setting rates.

Line No.	Description	Amount (1)
1	Customer deposits included in rate base (Exhibit RAD-1, Column 1, Line 14	$ 20,925
2	Interest rate on deposits	6%
3	Interest expense on customer deposits	$ 1,256

Metropolitan Edison Company
Normalization Adjustment No. 6
$000

Adjustment of Customer Service and Information Expense

To adjust customer service and information expense to reflect year end wage and employee levels.

Line No.	Description	Amount (1)	Amount (2)
1	Customer Service expense per budget for the 12 months ending 3/31/2015		$ 44,208
2	Customer Service payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 16, Column 1)	$ 50	
3	Total normalizing adjustment		50
4	Customer Service expense per budget for the 12 months ending 3/31/2015, as adjusted		$ 44,258

Metropolitan Edison Company
Normalization Adjustment No. 7
$000

Adjustment of Administrative and General Expense

To adjust Administrative and General expenses to reflect year end wage and employee levels, service company year end wage and employee levels, OPEB expense at the service cost level, pension expense to the ten year cash level, employee benefits expenses at year end personnel and wage levels, the elimination of non-jurisdictional administrative and general expenses, normalization of rate case expenses, eliminate legacy meters in the budget, and include costs to update computer system to allow accelerated (3 day) switching from one supplier to another. Hillary Stewart supports the non-jurisdictional expense allocation factor.

Line No.	Description	Amount (1)	Amount (2)
1	Administrative & general expense per budget for the 12 months ending 3/31/2015		$ 37,806
2	Administrative & general expenses related to EE&C	$ (24,389)	
3	Administrative & general expenses related to Smart Meters	(11,732)	
4	Adjustment to administrative & general expenses	(36,121)	
5	Net administrative & general expenses related to distribution	1,685	
6	Administrative & general payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates, (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 17, Column 1)	$ 86	
7	Service Company Administrative & general payroll expense adjustment allocated to Met-Ed to reflect year end employee levels and ongoing wage & salary rates (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 28, Column 1)	263	
8	Adjust OPEB expense to service cost level (Normalization Adjustment No. 7, Supporting Schedule No. 1, Line 12, Col. 1)	5,796	
9	Adjust pension expense to ten year cash level (Supporting Schedule No. 2, Line 18, Column 3)	14,259	
10	Adjust employee benefit costs (Supporting Schedule No. 3, Line 8, Column 3)	345	
11	Subtotal of adjustments (Lines 6 + 7 + 8 + 9 + 10)		20,749
12	Administrative and general expense, adjusted	$ 22,434	
13	Non-jurisdictional expense allocation factor	10.43%	
14	Non-jurisdictional administrative and general expense		(2,340)
15	Rate case expenses to be incurred during current rate proceeding (Exhibit RAD-23)	$ 495	
16	Recovery period - years	2	
17	Annual amount (Line 15 / Line 16)	$ 248	
18	Less rate case expenses in budget	(750)	
19	Adjusted total		$ (502)
20	Less legacy meters from budget		(1)
21	Increase in O&M costs for accelerated (3 day) switching for customers moving to a new supplier (Exhibit RAD-64)		311
22	Total normalizing adjustment (Lines 11 + 14 + 19 + 20 + 21)		$ 18,217
23	Administrative and general expense per budget for the 12 months ending 3/31/2015, as adjusted		$ 56,023

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 7
$000

Adjustment for OPEB Expense

Budgeted OPEB expense consists of the current service cost, adjustments to prior years' service costs, and the financing component. This schedule adjusts the total budgeted expense amounts to the service cost. The service cost represents the actuarial present value of benefit liabilities accrued under the plan benefit formula for services rendered during the test year. Inclusion of the service cost in rates provides for recovery of the current cost of benefits earned by plan participants. Any excess or shortfall related to the expected return on plan assets are not included because their inclusion would artificially reduce or increase total costs and result in the recovery of more or less than the actual normal cost of service. The adjustment for OPEB expense to the current service cost amount was adopted by the Commission at Docket Nos. R-00061366 and R-00061367

Line No.	Description	O&M	Capital	Total
		(1)	(2)	(3)
1	O&M - Capital allocation ratios	39.67%	60.33%	100.00%
2	Company OPEB expense included in budget	$ (4,672)	$ (7,105)	$ (11,777)
3	FirstEnergy Service Corp. OPEB expense	$ (15,287)	$ (23,249)	$ (38,537)
4	Allocation ratio	5.54%	5.54%	5.54%
5	Allocated FirstEnergy Service Corp. OPEB expense included in budget (Line 3 X Line 4)	$ (847)	$ (1,288)	$ (2,135)
6	Total OPEB expense included in budget (Line 2 + Line 5)	$ (5,519)	$ (8,393)	$ (13,912)
7	Service cost for company OPEB expense	$ 258	$ 393	$ 651
8	Service cost for FirstEnergy Service Corp. OPEB expense	$ 335	$ 510	$ 845
9	Allocation ratio	5.54%	5.54%	5.54%
10	Allocated FirstEnergy Service Corp. service cost (Line 8 X Line 9)	$ 19	$ 28	$ 47
11	Total OPEB service cost (Lines 7 + 10)	$ 277	$ 421	$ 698
12	Adjustment to set OPEB expense at ongoing service cost level (Lines 11 - 6)	$ 5,796	$ 8,814	$ 14,610

Metropolitan Edison Company
Supporting Schedule No. 2 to Normalizing Adjustment No. 7
$000

Adjustment for Pension Expense

To adjust budget pension expense to a ten year historical average level of actual cash contributions under the methodolc

Line No.	Description	Amount (1) Total	(2) O&M %	(3) O&M
	Company Cash Contributions			
1	2004 Cash Pension Contribution	$ 38,823	56.52%	$ 21,943
2	2005 Cash Pension Contribution	35,912	56.52%	20,297
3	2007 Cash Pension Contribution	11,012	55.42%	6,103
4	2009 Cash Pension Contribution	123,521	50.49%	62,366
5	2011 Cash Pension Contribution	35,000	45.09%	15,782
6	Total Company Cash Pension Contributions	$ 244,268		$ 126,490
	FirstEnergy Service Company Cash Contributions			
7	2004 Pension Contribution	$ 91,633		
8	2004 Company Allocation Factor	8.91%		
9	2004 Service Company Pension Contribution allocated to the Company	$ 8,165	56.52%	$ 4,615
10	2007 Pension Contribution	$ 27,468		
11	2007 Company Allocation Factor	11.29%		
12	2007 Service Company Pension Contribution allocated to the Company	$ 3,101	55.42%	1,719
13	Total FirstEnergy Service Company Cash Pension Contributions allocated to the Company (Line 9 + Line 12)	$ 11,266		$ 6,333
14	Total Pension cash contributions (Line 6 + Line 13)	$ 255,534		$ 132,824
15	Average	10		10
16	Pension expense cash contribution, amortized over 10 years	$ 25,553		$ 13,282
17	O&M Pension Expense included in budget			(977)
18	Adjustment to Pension Expense (Line 16 - Line 17)			$ 14,259

Metropolitan Edison Company
Supporting Schedule No. 3 to Normalizing Adjustment No. 7
$000

Adjustment to Employee Benefit Expense to Reflect Year End Employee Levels and Ongoing Wage Rates

Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 10 increases the O&M payroll expense. Associated with that increase are employee benefits charged to Administrative and General expense. This adjustment computes the added benefit costs on a normalized basis.

Employee benefits applicable to operating expenses:

Line No.		Effective Rate (a)	Payroll Adjustment		Benefit Adjustment
		(1)	(2)		(3) = (1) X (2)
1	Workers compensation	0.716%	$ 592	(b)	$ 4
2	Pension costs	40.873%	$ 592	(b)	242
3	OPEB costs	1.089%	$ 592	(b)	6
4	Life insurance	0.166%	$ 592	(b)	1
5	Medical insurance	9.081%	$ 592	(b)	54
6	Savings Plan	3.748%	$ 592	(b)	22
7	Other	2.651%	$ 592	(b)	16
8	Total increase due to payroll adjustment				$ 345

(a) Summary of effective employee benefit rates based on total payroll for the 12 months ending 3/31/15

	Total Amount	Total Payroll	Effective Rate
Workers compensation	$ 428	$ 59,762	0.716%
Pension costs - normalized basis	24,427	59,762	40.873%
OPEB costs - service cost	651	59,762	1.089%
Life Insurance (Exhibit RAD-27)	99	59,762	0.166%
Medical insurance	5,427	59,762	9.081%
Savings Plan	2,240	59,762	3.748%
Other	1,584	59,762	2.651%

(b) Adjustment No. 4, Supporting Schedule No. 1, Line 10.

Metropolitan Edison Company
Normalization Adjustment No. 8
$000

Adjustment of Depreciation Expense

To adjust budgeted depreciation expense to reflect average remaining life rates on adjusted rate base, to eliminate non-jurisdictional expense, and to adjust cost of removal/ salvage expense to a five year average amount, according to prior commission practice and the adjustment of legacy meters. The plant allocation factor used in this normalization adjustment are supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	(2)	(3)	(4)
1	Depreciation expense per budget for the 12 months ending 3/31/2015				$ 59,573
2	Cost of removal/salvage expense per budget for the 12 months ending 3/31/2015 (Exhibit RAD-30)		$ 4,453		
3	Depreciation accrual per budget (Line 1 - Line 2)		$ 55,120		
4	Jurisdictional depreciation expense accrual on adjusted rate base at average remaining life rates (Exhibit RAD-53, page 2)		47,150		
5	Adjustment for average remaining life accrual for jurisdictional plant, (Line 4 - Line 3).			(7,970)	
6	Cost of removal/salvage expense per budget for the 12 months ending 3/31/2015 (Exhibit RAD-30)		$ 4,453		
	Cost of removal and salvage (Exhibit RAD-30)				
7	4/1/2010 - 3/31/2011	$ 17,539			
8	4/1/2011 - 3/31/2012	7,101			
9	4/1/2012 - 3/31/2013	17,511			
10	4/1/2013 - 3/31/2014	28,248			
11	4/1/2014 - 3/31/2015	10,222			
12	Total	$ 80,620			
13	Five year average (Line 12 / 5)		$ 16,124		
14	Allocation ratio based on jurisdictional plant		77.70%		
15	Jurisdictional cost of removal/salvage expense to a jurisdictional five year average (Line 13 x Line 14)		$ 12,528		
16	Adjustment of jurisdictional cost of removal/salvage expense to a jurisdictional five year average (Line 15 - Line 6)			8,075	
17	Adjustment for acceleration of legacy meters (Adj. 8 Sched 1, Line 6)			11,140	
18	Total normalizing adjustment (Lines 5 + 16 + 17)				11,245
19	Depreciation expense per budget for the 12 months ending 3/31/2015, as adjusted				$ 70,818

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 8
$000

Adjustment for Acceleration for legacy meters

To accelerate recovery of legacy meters to fully recover all legacy meter costs over 5 years.

Line No.	Description	Amount (1)	Amount (2)
1	Legacy meters per budget for the 12 months ending 3/31/2015	$ 66,795	
2	Depreciation reserve per budget for the 12 months ending 3/31/2015	14,728	
3	Net legacy meters per budget for the 12 months ending 3/31/2015	$ 52,067	
4	Net estimated cost of removal and salvage	3,631	
5	Net legacy meters	$ 55,698	
6	Annual amortization over a 5 year amortization period		$ 11,140

Metropolitan Edison Company
Normalization Adjustment No. 9
$000

Adjustment of Amortization Expense

To include the amortization of deferred storm damage balances for Winter Storm Nika, approved at Docket No. P-2014-2412229, Hurricane Sandy, approved at Docket No. P-2013-2351260, and distribution non-capital storm expenses that exceeded 125% of storm costs included in base rates between the period of February 25, 2011 through September 30, 2012 as a result of the FirstEnergy and Allegheny Merger approved at Docket Nos. A-2010-2176520 and A-2010-2176732, including but not limited to Hurricane Irene, the October 2011 snowstorm, and Tropical Storm Lee. In addition, rate case expenses, legacy meters, and accretion expense are removed from the budget.

Line No.	Description	Amount (1)	Amount (2)	Amount (3)
1	Amortization expense per budget for the 12 months ending 3/31/2015			$ 13,023
2	Deferred Nika storm damage	$ 13,327		
3	Deferred Sandy storm damage	21,497		
4	Merger storm deferral	30,140		
5	Total deferred storms (Lines 2 + 3 + 4)	$ 64,964		
6	Amortized over 3 years	3		
7	Annual Amortization		$ 21,655	
8	Remove rate case expenses		750	
9	Remove legacy meters from budget		1	
10	Remove accretion expense		(62)	
11	Normalization adjustment (Lines 7 + 8 + 9 + 10)			22,344
12	Amortization expense per budget for the 12 months ending 3/31/2015			$ 35,367

Metropolitan Edison Company
Normalization Adjustment No. 10
$000

Adjustment of Taxes Other Than Income

To adjust gross receipts tax expense to reflect normalized sales revenues, to adjust payroll tax expenses for normalized payroll and employee expenses. The non-jurisdictional allocation factor is supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	Amount (2)	Amount (3)
1	Taxes Other Than Income per budget for the 12 months ending 3/31/2015			$ 46,882
2	Federal and State payroll taxes in budget	$ 4,523		
3	Non-jurisdictional percent	10.43%		
4	Eliminate non-jurisdictional payroll taxes		$ (472)	
5	Capital Stock Tax included in budget	$ 346		
6	PURTA tax in budget	1,954		
7	Real Estate tax in budget	130		
8	Total Other taxes	$ 2,430		
9	Non-jurisdictional percent	22.30%		
10	Eliminate non-jurisdictional taxes		(542)	
	Gross Receipts Tax			
11	Normalized sales revenues (Exhibit RAD-4, page 1, Col. 3)	$ 675,031		
12	Gross receipts tax @ 5.9%	39,827		
13	Gross receipts tax included in budget	39,817		
14	Adjustment for gross receipts tax at normalized revenue level (Line 12 - Line 13)		10	
15	Adjustment for payroll taxes on normalized payroll (Supporting Schedule No. 1, Line 8)		45	
16	Total normalizing adjustment (Lines 4+10+14+15)			(959)
17	Taxes other than income per budget for the 12 months ending 3/31/2015, as adjusted			$ 45,923

Metropolitan Edison Company
Supporting Schedule No.1 to Normalizing Adjustment No. 10
$000

Adjustment to Taxes Other Than Income to reflect changes in payroll taxes.

Normalization adjustments have been made to normalize O&M payroll expense. Associated with those payroll normalizations are changes in FICA tax amounts.

Line No.	Description	Amount (1)
1	Total payroll per budget for the 12 months ending 3/31/2015 (Normalization Adjustment No. 4, Schedule 1, Line 1, Col 2)	$ 59,762
2	Total payroll tax included in budget	4,523
3	Effective payroll tax rate (Line 2 / Line 1)	7.568%
4	Total payroll as adjusted (Normalization Adjustment No. 4, Schedule 1, Line 11, Col. 2)	$ 61,254
5	Payroll tax on normalized payroll (Line 3 x Line 4)	$ 4,636
6	Total Company payroll tax adjustment (Line 5 - Line 2)	$ 113
7	O&M Allocation percentage	39.67%
8	Adjustment for payroll tax (Line 6 x Line 7)	$ 45

Metropolitan Edison Company
Normalization Adjustment No. 11
$000

Computation of Federal & State Income Taxes - Normalized

Line No.	Description	Total Company Calculated Taxes (1)	PTC Calculated Taxes (2)	Distribution Calculated Taxes (3)	Universal Service Calculated Taxes (4)	Energy Efficiency Calculated Taxes (5)	Smart Meter Rider Calculated Taxes (6)	DSS Calculated Taxes (7)	Solar Calculated Taxes (8)	NUG Charge Calculated Taxes (9)	Storm Rider Calculated Taxes (10)
1	Total operating revenue	$ 713,124	$ 332,477	$ 267,788	$ 21,501	$ 25,512	$ 13,760	$ 39,274	$ 3,060	$ 9,752	$ -
2	Less: Total O& M Expense	494,727	320,256	92,048	25,062	24,389	11,732	19,111	2,129	$ -	$ -
3	Depreciation - accrual	58,290	-	56,941	-	-	1,349	-	-	-	-
4	Average net salvage	12,528	-	12,528	-	-	-	-	-	-	-
5	Amortization	35,367	(5,713)	21,655	(4,312)	(377)	(1,066)	15,233	770	9,177	-
6	Taxes other than income taxes	45,923	18,471	20,798	1,269	1,500	812	2,317	181	575	-
7	Total deductions	$ 646,835	$ 333,014	$ 203,970	$ 22,019	$ 25,512	$ 12,827	$ 36,662	$ 3,080	$ 9,752	$ -
8	Net operating income before income taxes	$ 66,289	$ (537)	$ 63,818	$ (518)	$ -	$ 934	$ 2,612	$ (19)	$ -	$ -
9	Less: Interest Charges (A)	35,733	-	35,481	-	-	252	-	-	-	-
10	Net income before income taxes	$ 30,556	$ (537)	$ 28,337	$ (518)	$ -	$ 682	$ 2,612	$ (19)	$ -	$ -
	Adjustments to taxable income:										
11	Book Average net salvage	12,528	-	12,528	-	-	-	-	-	-	-
12	Adj. of book depreciation to tax basis (B)	$ 28,474	$ -	$ 27,778	$ -	$ -	$ 696	$ -	$ -	$ -	$ -
13	Tax cost of removal/salvage	(6,472)	-	(6,472)	-	-	-	-	-	-	-
14	Adjust cash pension	14,259	-	14,259	-	-	-	-	-	-	-
15	Net adjustment	48,790	-	48,095	-	-	696	-	-	-	-
16	Income subject to state income tax	79,346	(537)	76,431	(518)	-	1,378	2,612	(19)	-	-
17	State income tax @ 9.99%	$ 7,927	$ (54)	$ 7,636	$ (52)	$ -	$ 138	$ 261	$ (2)	$ -	$ -
18	Taxes as budgeted	-	-	-	-	-	-	-	-	-	-
19	Adjustment to state income tax	$ 7,927	$ (54)	$ 7,636	$ (52)	$ -	$ 138	$ 261	$ (2)	$ -	$ -
20	Income subject to federal income tax	$ 71,420	$ (484)	$ 68,796	$ (466)	$ -	$ 1,240	$ 2,351	$ (18)	$ -	$ -
21	Federal income tax @ 35%	$ 24,997	$ (169)	$ 24,079	$ (163)	$ -	$ 434	$ 823	$ (6)	$ -	$ -
22	Taxes as budgeted	25,303	-	25,303	-	-	-	-	-	-	-
23	Adjustment to federal income tax	$ (306)	$ (169)	$ (1,224)	$ (163)	$ -	$ 434	$ 823	$ (6)	$ -	$ -
	(A) Computation of Interest charges										
	Total rate base	$ 1,370,628	$ -	$ 1,360,959	$ -	$ -	$ 9,669	$ -	$ -	$ -	$ -
	Debt ratio	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%
	Cost of debt	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%
	Interest expense	$ 35,733	$ -	$ 35,481	$ -	$ -	$ 252	$ -	$ -	$ -	$ -
	(B) Adjustment of book depreciation to tax basis:										
	Tax depreciation	29,815	-	29,162	-	-	653	-	-	-	-
	Book depreciation	58,290	-	56,941	-	-	1,349	-	-	-	-
	Depreciation adjustment	(28,474)	-	(27,778)	-	-	(696)	-	-	-	-

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalization Adjustment No. 11
$000

Computation of Federal & State Income Taxes - Normalized

To (1) split the tax depreciation into cost of removal, smart meter, and distribution components, and (2) calculate the jurisdictional allocation.

Line No.	Description		Amount (1)	Amount (2)
1	Tax depreciation expense per budget (Exhibit RAD-33)	$	46,514	
2	Cost of removal / salvage		8,329	77.70%
3	Smart meter tax depreciation		653	100.00%
4	Distribution tax depreciation		37,532	77.70%
5	Total tax depreciation			

Metropolitan Edison Company
Normalization Adjustment No. 12
$000

Adjustment of Provision for Deferred Income Taxes

This adjustment to the Provision for Deferred Income Taxes reflects (1) the adjustment of Federal deferrals to reflect year-end plant. All state deferred taxes associated with liberalized depreciation have been eliminated.

Line No.	Description	Provision for Deferred Taxes - Net	
		Federal	State
		(1)	(2)
1	Deferred taxes per budget, 12 months ending 3/31/2015	$ 27,321	$ -
2	Deferred taxes - liberalized depreciation (Exhibit RAD-41, page 20)	12,403	-
3	Jurisdictional allocation factor	77.70%	77.70%
4	Jurisdictional deferred taxes - liberalized depreciation (Line 2 x Line 3)	9,637	-
5	Adjustment to deferred tax expense (Line 4 - Line 1)	(17,684)	-
6	Deferred tax expense per budget for the 12 months ending 3/31/2015, as adjusted	$ 9,637	$ -

Metropolitan Edison Company
Normalization Adjustment No. 13
$000

Adjustment of Investment Tax Credit

This adjustment includes the investment tax credit and eliminates the non-jurisdictional portion of investment tax

Line No.	Description	Amount (1)	Amount (2)
1	Investment tax credit adjustments per budget, 12 months ending 3/31/2015		$ (364)
2	Jurisdictional allocation factor	77.70%	
3	Jurisdictional investment tax credit	$ (283)	
4	Adjustment to investment tax credit expense (Line 3 - Line 1)		81
5	Adjustment to investment tax credit expense per budget for the 12 months ending 3/31/2015, as adjusted		$ (283)

METROPOLITAN EDISON COMPANY
Rate Base At Original Cost
Normalized To Year-End Conditions at March 31, 2014
($000)

Line No.	Description	Per Budget	Adjustments and Normalizations	Adj No.	Total	Pa Jurisdictional Normalized Rate Base: Distribution	Smart Meter Costs	PA Jurisdictional Total
		(1)	(2)		(3)	(4)	(5)	(6) = (4) + (5)
	Electric Plant:							
1	Plant in service	$ 2,699,281	$ (608,677)	1	$ 2,090,604	$ 2,088,147	$ 2,457	$ 2,090,604
2	Plant held for future use	596	(596)	2	-	-	-	-
3	Construction work in progress - pollution control and safety	-	-		-	-	-	-
		-	-		-	-	-	-
4	Total electric plant	$ 2,699,877	$ (609,273)		$ 2,090,604	$ 2,088,147	$ 2,457	$ 2,090,604
	Depreciation & Amortization Reserve:							
5	Plant in Service	$ 959,316	$ (289,003)	3	$ 670,313	$ 670,177	$ 136	$ 670,313
6	Plant held for future use	-	-		-	-	-	-
7	Total depreciation & amortization reserve	$ 959,316	$ (289,003)		$ 670,313	$ 670,177	$ 136	$ 670,313
8	Net Electric Plant	$ 1,740,561	$ (320,270)		$ 1,420,291	$ 1,417,970	$ 2,321	$ 1,420,291
	Additions:							
9	Cash working capital	$ -	$ 147,828	4	$ 147,828	$ 147,828	$ -	$ 147,828
10	M&S inventories	-	14,493	5	14,493	14,493	-	14,493
11	Deferred storm damage	-	64,964	6	64,964	64,964	-	64,964
12	Legacy meters	-	58,341	7	58,341	58,341	-	58,341
13	Total additions	$ -	$ 285,627		$ 285,627	$ 285,627	$ -	$ 285,627
	Deductions:							
14	Customer deposits	$ 21,452	$ -		$ 21,452	$ 21,452	$ -	$ 21,452
15	Customer advances for construction	19	-		19	19	-	19
16	Accum. Deferred income taxes - Liberalized depreciation	478,696	(130,107)	8	348,589	347,991	598	348,589
17	Operating reserves (net of taxes)	653	(146)	9	508	508	-	508
18	Total deductions	$ 500,820	$ (130,253)		$ 370,568	$ 369,970	$ 598	$ 370,568
19	Total Rate Base	$ 1,239,741	$ 95,609		$ 1,335,350	$ 1,333,627	$ 1,723	$ 1,335,350
20	Pro forma return at present rates (PA Distribution)	$ 30,254	Dollars					
21		2.27%	Percent					
22	Pro forma return at proposed rates (PA Distribution)	$ 107,517	Dollars					
23		8.05%	Percent					

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 1
($000)

Adjustment of Electric Plant in Service

To adjust the budgeted gross plant in service to (1) eliminate the Asset Retirement Cost ("ARC"). An asset retirement cost ("ARC") increases the carrying amount of a long-lived asset when a liability for an asset retirement obligation ("ARO") is recognized. The ARC is depreciated over the life of the asset. The ARC and related reserve are excluded from Rate Base, while the associated depreciation expense is excluded from the Income Statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18 Asset retirement obligations; (2) remove FERC Transmission Plant which is non-jurisdictional; (3) remove an allocated portion of Intangible Plant that supports FERC Transmission Plant; (4) remove an allocated portion of General Plant that supports FERC Transmission Plant; and (5) remove legacy meters as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Adjustments	Plant in Service	Cross Reference
		(1)	(2)	(3)
1	Actual Plant in Service at March 31, 2014		$ 2,699,281	Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2
	Normalizing adjustments:			
2	Eliminate ARC	$ (95,358)		Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2
3	Remove FERC transmission plant	(397,455)		Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2
4	Remove allocated portion of Intangible Plant associated with FERC Transmission Plant	(6,478)		Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2
5	Remove allocated portion of General Plant associated with FERC Transmission Plant	(42,590)		Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2
6	Remove legacy meters	(66,795)		Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2
7	Normalization adjustment		(608,677)	
8	Plant in Service at 3/31/2014, as adjusted		$ 2,090,604	Met-Ed Exhibit RAD-48, Attach. B, p. 1 and 2

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 2
($000)

Adjustment of Plant Held for Future Use

To adjust Plant Held for Future Use. As an alternative to rate base treatment, the Company is requesting the allowance of deferred carrying charges on any current or future investments in Plant Held for Future Use with definitive plans of utilization within a ten-year period. This is consistent with long-standing Commission policy.

Line No.		Amount (1)
1	Actual Plant Held for Future Use at 3/31/2014	$ 596
	Normalizing adjustment:	
2	Eliminate Plant Held for Future Use	(596)
3	Plant Held for Future Use at 3/31/2014, as adjusted	$ -

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 3
($000)

Adjustment of Depreciation Reserves - Plant In Service

To adjust the budgeted plant in service depreciation reserves to (1) eliminate the Asset Retirement Cost ("ARC") reserves. An asset retirement cost ("ARC") increases the carrying amount of a long-lived asset when a liability for an asset retirement obligation ("ARO") is recognized. The ARC is depreciated over the life of the asset. The ARC and related reserve are excluded from Rate Base, while the associated depreciation expense is excluded from the Income Statement. This treatment is in accordance with 18 CFR Chapter 1 § 35.18 Asset retirement obligations; (2) remove FERC Transmission Plant reserves which are non-jurisdictional; (3) remove an allocated portion of Intangible Plant reserves that support FERC Transmission Plant; (4) remove an allocated portion of General Plant reserves that support FERC Transmission Plant; (5) and remove legacy meters as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Adjustments	Depreciation Reserves Plant in Service	Cross Reference
		(1)	(2)	(3)
1	Actual plant in Service depreciation reserves at 3/31/2014		$ 959,316	Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
	Normalizing adjustments:			
2	Eliminate ARC	$ (95,342)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
3	Remove FERC Transmission Plant	(148,796)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
4	Remove allocated portion of Intangible Plant associated with FERC Transmission Plant	(5,092)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
5	Remove allocated portion of General Plant associated with FERCTransmission Plant	(27,687)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
6	Remove legacy meters	(12,085)		Met-Ed Exhibit RAD-46, Attach. B, p. 3 and 4
7	Normalization Adjustment		(289,003)	
8	Plant in Service depreciation reserves at 3/31/2014, as adjusted		$ 670,313	

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 4
($000)

Adjustment of Cash Working Capital

To recognize cash working capital at year-end level. This adjustment is supported by Met-Ed's Witness Patricia M. Larkin.

Line No.		Cash Working Capital (1)	Cash Working Capital (2)
1	Cash working capital per books at 3/31/2014		$ -
	Normalizing adjustment:		
2	Cash working capital normalized to year-end (Exhibit PML-1)	$147,828	
3	Cash working capital per budget	-	
4	Normalization Adjustment		147,828
5	Cash working capital at 3/31/2014, as adjusted		$ 147,828

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 5
($000)

Adjustment of Material and Supplies Inventories

To recognize the Company's distribution portion of FE Service material and supplies ("M&S") inventory levels projected at 3/31/2014

Line No.		M&S Inventories (1)	M&S Inventories (2)
1	M&S Inventory per books at 3/31/2014		$ -
	Normalizing adjustment:		
2	Distribution component of projected FE Service M&S Inventory allocated to Met-Ed at 3/31/2014 (Exhibit RAD-13)	$ 14,493	
3	M&S Inventory per books at 3/31/2014	-	
4	Normalization Adjustment		14,493
5	M&S inventory at 3/31/2014, as adjusted		$ 14,493

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 6
($000)

Adjustment of Deferred Storm Damage Expenses

To include in rate base the deferred storm damage balances for Winter Storm Nika, approved at Docket No. P-2014-2412229, Hurricane Sandy, approved at Docket No. P-2013-2351260, and distribution non-capital storm expenses that exceeded 125% of storm costs included in base rates between the period of February 25, 2011 through September 30, 2012 as a result of the FirstEnergy and Allegheny Merger approved at Docket Nos. A-2010-2176520 and A-2010-2176732, including but not limited to Hurricane Irene, the October 2011 snowstorm, and Tropical Storm Lee.

Line No.		Storms	
		(1)	(2)
1	Unamortized storm deferral expense per books at 3/31/2014		$ -
2	Deferred Nika storm damage	13,327	
3	Deferred Sandy storm damage	21,497	
4	Merger storm damage deferral	30,140	
5	Normalization less storm per books Adjustment (Sum of Lines 2 + 3 + 4)		64,964
6	Storm Expense at 3/31/2014 as adjusted		$ 64,964

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 7
($000)

Adjustment to Include Legacy Meters in Regulatory Asset

To include legacy meters in a regulatory asset as ordered in the Final Order on the Smart Meter Deployment Plan at Docket No. M-2013-2341990.

Line No.		Legacy Meters (1)	Legacy Meters (2)
1	Net legacy meters in regulatory asset		$ -
2	Legacy meters per books at 3/31/2014	$ 66,795	
3	Net estimated cost of removal and salvage	3,631	
4	Depreciation reserve per books at 3/31/2014	(12,085)	
5	Net legacy meters normalizing adjustment (Lines 3 + 4 + 5)		58,341
6	Net legacy meters in regulatory asset as adjusted at 3/31/2014		$ 58,341

METROPOLITAN EDISON COMPANY
Normalization Adjustment No. 8
($000)

Adjustment of Accumulated Deferred Income Taxes - Liberalized Depreciation

This adjustment adjusts the budgeted deferred tax balances for liberalized depreciation (excluding the impact of SFAS No. 109 deferrals) to (1) eliminate the deferred income taxes - liberalized depreciation balances associated with TMI-2; (2) eliminate deferred income taxes - liberalized depreciation associated with other generation; (3) eliminate other excludable items (capital leases); (4) eliminate remaining state deferred taxes - liberalized depreciation balances including the federal benefit of those taxes; and (5) eliminate an allocated portion of the remaining federal deferred income taxes - liberalized depreciation balance associated with FERC Transmission Plant.

Line No.		Adjustments (1)	Accum Reserve for Deferred Taxes - Liberalized Depreciation (2)
1	Deferred taxes per books - liberalized depreciation at 3/31/2014		$ 478,696
	Normalizing adjustments:		
2	Eliminate deferred income taxes - liberalized depreciation associated with TMI-2 (federal and state)	$ 2,954	
3	Eliminate deferred income taxes - liberalized depreciation associated with other generation (federal and state)	(97)	
4	Eliminate other excludable items - capital leases (federal and state)	(17,014)	
5	Eliminate remaining state deferred taxes - liberalized depreciation including the federal benefit of those taxes	(15,904)	
6	Eliminate an allocated portion of the remaining federal deferred income taxes - liberalized depreciation associated with FERC Transmission Plant	(100,046)	
7	Normalization Adjustment		(130,107)
8	Deferred taxes - liberalized depreciation at 3/31/2014, as adjusted		$ 348,589

METROPOLITAN EDISON COMPANY

Normalization Adjustment No. 9
($000)

Adjustment of Operating Reserves

To adjust operating reserves (net of accumulated deferred income taxes) to eliminate an allocated portion associated with FERC Transmission operations.

Line No.		Amount
1	Operating reserves, net of taxes, per books at 3/31/2014	$ 653
2	Eliminate portion of operating reserves associated with FERC Transmission operations	(146)
3	Operating reserves, net of taxes at 3/31/2014, as adjusted	$ 508

METROPOLITAN EDISON COMPANY

Rate of Return at March 31, 2014
($000)

Line No.	Description	Exhibit SRS-24 Capital Amounts (1)	Capital Ratios (2)	Cost Rate (3)	Weighted Cost Rate (4) = (2) X (3)
1	Total long-term debt	$ 849,707	50.04%	5.21%	2.61%
2	Total preferred stock	-	0.00%	0.00%	0.00%
3	Total Common Equity	848,489	49.96%	10.90%	5.44%
4	Total Capitalization	$ 1,698,196	100.00%		8.05%

Metropolitan Edison Company
Statement of operating Income, 12 Months Ended March 31, 2014, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Per Budget	Normalizations & Adjustments	Adj. No.	Budget as Adjusted	Distribution	Normalized PaPUC Jurisdictional									
							Riders									
							Price to Compare	Universal Service	Energy Efficiency	Smart Meters	Default Service Support	Solar	NUG	Storm	CEC	PaPUC Distribution Total
		(1)	(2)		(3)=(1)+(2)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14) = (4) + (8)
	Operating revenues															
1	Retail sales	$ 741,232	$ (12,553)	1	$ 728,679	$ 245,159	$ 379,832	$ 28,882	$ 29,074	$ 7,831	$ 26,795	$ 2,651	$ 8,194	$ -	$ 261	$ 252,990
2	STAS revenue	(2,123)	2,123	2	-	-	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	26,062	-		26,062	15	25,590	-	457	-	-	-	-	-	-	15
4	Other operating revenue	70,921	(56,257)	3	14,664	19,328	(4,664)	-	-	-	-	-	-	-	-	19,328
5	Total operating revenue	836,092	(66,687)		769,405	264,502	400,758	28,882	29,531	7,831	26,795	2,651	8,194	-	261	272,333
	Operating expenses															
6	Price to Compare	382,374	-		382,374	52	380,800	-	-	-	-	1,522	-	-	-	52
7	Distribution	67,795	(6,717)	4	61,078	52,939			-	-	8,139	-	-	-	-	52,939
8	Customer accounts	24,842	1,536	5	26,378	18,793	-	-	-	-	7,585	-	-	-	-	18,793
9	Customer service & info	40,005	48	6	40,053	15,035	-	24,409	-	-	318	-	-	-	290	15,035
10	Admin & gen expense	6,525	31,487	7	38,012	9,349	-	-	21,093	7,570	-	-	-	-	-	16,919
11	Depreciation - accrual	58,193	10,824	8	69,017	68,888	-	-	-	129	-	-	-	-	-	69,017
12	Amortization & Accretion	12,250	21,597	9	33,847	11,795	(2,118)	3,164	6,659	(377)	6,232	938	7,573	-	(19)	11,418
13	Taxes other than income	50,525	(1,298)	10	49,227	20,663	22,492	1,749	1,779	443	1,305	156	621	-	20	21,106
14	Operating expense before tax	642,508	57,475		699,984	197,513	401,175	29,321	29,531	7,765	23,579	2,615	8,194	-	291	205,277
15	Operating income before incon	193,583	(124,162)		69,422	66,989	(416)	(440)	-	66	3,216	36	-	-	(30)	67,056
	Income taxes															
16	Federal income tax - current	28,956	(8,069)	11	20,887	20,294	(131)	(139)	-	(153)	1,013	11	-	-	(9)	20,141
17	State income tax - current	5,701	922	11	6,623	6,435	(42)	(44)	-	(48)	321	4	-	-	(3)	6,387
18	Deferred income tax - federal	(59,116)	69,697	12	10,581	10,372	-	-	-	209	-	-	-	-	-	10,581
19	Deferred income tax - state		-	12	-		-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	(397)	89	13	(308)	(308)	-	-	-	-	-	-	-	-	-	(308)
21	Total tax expense	(24,856)	62,639		37,783	36,794	(173)	(182)	-	8	1,335	15	-	-	(12)	36,801
22	Total operating expenses	617,652	120,114		737,767	234,306	401,002	29,139	29,531	7,772	24,913	2,630	8,194	-	279	242,079
23	**Operating income**	$ 218,439	$ (186,801)		$ 31,638	$ 30,196	$ (244)	$ (257)	$ -	$ 58	$ 1,882	$ 21	$ -	$ -	$ (17)	$ 30,254

Metropolitan Edison Company
Statement of operating Income, 12 Months Ended March 31, 2014, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Distribution	Riders: Price to Compare	Universal Service	Energy Efficiency	Smart Meters	Default Service Support	Solar	NUG	Storm	CEC	PaPUC Total
		(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25) = (15) + (19)
	Operating revenues											
1	Retail sales	$ 140,193	$ -	$ -	$ -	$ 146	$ -	$ -	$ -	$ -	$ -	$ 140,339
2	STAS revenue	-	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	-	-	-	-	-	-	-	-	-	-	-
4	Other operating revenue	-	-	-	-	-	-	-	-	-	-	-
5	Total operating revenue	140,193	-	-	-	146	-	-	-	-	-	140,339
												-
	Operating expenses											-
6	Price to Compare	-	-	-	-	-	-	-	-	-	-	-
7	Distribution	-	-	-	-	-	-	-	-	-	-	-
8	Customer accounts	-	-	-	-	-	-	-	-	-	-	-
9	Customer service & info	-	-	-	-	-	-	-	-	-	-	-
10	Admin & gen expense	-	-	-	-	-	-	-	-	-	-	-
11	Depreciation - accrual	-	-	-	-	-	-	-	-	-	-	-
12	Amortization	-	-	-	-	-	-	-	-	-	-	-
13	Taxes other than income	8,271	-	-	-	9	-	-	-	-	-	8,280
14	Operating expense before tax	8,271	-	-	-	9	-	-	-	-	-	8,280
												-
15	Operating income before incom	131,922	-	-	-	137	-	-	-	-	-	132,059
												-
	Income taxes											-
16	Federal income tax - current	41,560	-	-	-	43	-	-	-	-	-	41,603
17	State income tax - current	13,179	-	-	-	14	-	-	-	-	-	13,193
18	Deferred income tax - federal	-	-	-	-	-	-	-	-	-	-	-
19	Deferred income tax - state	-	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	-	-	-	-	-	-	-	-	-	-	-
21	Total tax expense	54,739	-	-	-	57	-	-	-	-	-	54,796
												-
22	Total operating expenses	63,010	-	-	-	66	-	-	-	-	-	63,076
												-
23	**Operating income**	$ 77,183	$ -	$ -	$ -	$ 80	$ -	$ -	$ -	$ -	$ -	$ 77,263

Metropolitan Edison Company
Statement of operating Income, 12 Months Ended March 31, 2014, Normalized and Adjusted to Reflect Revenue Necessary to Achieve Allowable Return
($000)

Line No.	Description	Distribution	Riders: Price to Compare	Riders: Universal Service	Riders: Energy Efficiency	Riders: Smart Meters	Riders: Default Service Support	Riders: Solar	Riders: NUG	Riders: Storm	CEC	PaPUC Total
		(26) = (4) + (15)	(27)	(28)	(29)	(30) = (8) + (19)	(31)	(32)	(33)	(34)	(35)	(36) = (26) + (30)
	Operating revenues											
1	Retail sales	$ 385,352	$ 379,832	$ 28,882	$ 29,074	$ 7,977	$ 26,795	$ 2,651	$ 8,194	$ -	$ 261	$ 393,329
2	STAS revenue	-	-	-	-	-	-	-	-	-	-	-
3	Sales for resale	15	25,590	-	457	-	-	-	-	-	-	15
4	Other operating revenue	19,328	(4,664)	-	-	-	-	-	-	-	-	19,328
5	Total operating revenue	404,695	400,758	28,882	29,531	7,977	26,795	2,651	8,194	-	261	412,672
	Operating expenses											
6	Price to Compare	52	380,800	-	-	-	-	1,522	-	-	-	52
7	Distribution	52,939	-	-	-	-	8,139	-	-	-	-	52,939
8	Customer accounts	18,793	-	-	-	-	7,585	-	-	-	-	18,793
9	Customer service & info	15,035	-	24,409	-	-	318	-	-	-	290	15,035
10	Admin & gen expense	9,349	-	-	21,093	7,570	-	-	-	-	-	16,919
11	Depreciation - accrual	68,888	-	-	-	129	-	-	-	-	-	69,017
12	Amortization	11,795	(2,118)	3,164	6,659	(377)	6,232	938	7,573	-	(19)	11,418
13	Taxes other than income	28,935	22,492	1,749	1,779	451	1,305	156	621	-	20	29,386
14	Operating expense before tax	205,784	401,175	29,321	29,531	7,773	23,579	2,615	8,194	-	291	213,557
15	Operating income before tax	198,911	(416)	(440)	-	204	3,216	36	-	-	(30)	199,115
	Income taxes											
16	Federal income tax - current	61,854	(131)	(139)	-	(109)	1,013	11	-	-	(9)	61,745
17	State income tax - current	19,614	(42)	(44)	-	(35)	321	4	-	-	(3)	19,580
18	Deferred income tax - federal	10,372	-	-	-	209	-	-	-	-	-	10,581
19	Deferred income tax - state	-	-	-	-	-	-	-	-	-	-	-
20	Investment tax credit	(308)	-	-	-	-	-	-	-	-	-	(308)
21	Total tax expense	91,532	(173)	(182)	-	65	1,335	15	-	-	(12)	91,597
		-				-				-	-	-
22	Total operating expenses	297,317	401,002	29,139	29,531	7,838	24,913	2,630	8,194	-	279	305,155
		-										-
23	**Operating income**	$ 107,379	$ (244)	$ (257)	$ -	$ 139	$ 1,882	$ 21	$ -	$ 139	$ -	$ 107,517
24	**Rate Base**	$1,333,627	-	$ -	$ -	$ 1,723	$ -	$ -	$ -	$ -	$ -	1,335,350
							$ -					
25	**Rate of Return overall**	8.05%				8.05%						8.05%
26	**Return on Equity**	10.90%				10.90%						10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Distribution
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 245,159	$ 140,193	$ 385,352
2	STAS revenue	-	-	-
3	Sales for resale	15	-	15
4	Other operating revenue	19,328	-	19,328
5	Total operating revenue	264,502	140,193	404,695
	Operating expenses			
6	PTC	52	-	52
7	Distribution	52,939	-	52,939
8	Customer accounts	18,793	-	18,793
9	Customer service & info	15,035	-	15,035
10	Admin & gen expense	9,349	-	9,349
11	Depreciation - accrual	68,888	-	68,888
12	Amortization	11,795	-	11,795
13	Taxes other than income	20,663	8,271	28,935
14	Operating expense before tax	197,513	8,271	205,784
15	Operating income before tax	66,989	131,922	198,911
	Income taxes			
16	Federal income tax - current	20,294	41,560	61,854
17	State income tax - current	6,435	13,179	19,614
18	Deferred income tax - federal	10,372	-	10,372
19	Deferred income tax - state	-	-	-
20	Investment tax credit	(308)	-	(308)
21	Total tax expense	36,794	54,739	91,532
22	Total operating expenses	234,306	63,010	297,317
23	**Operating income**	$ 30,196	$ 77,183	$ 107,379
24	**Rate Base**	1,333,627		1,333,627
25	**Rate of Return overall**	2.37%		8.05%
26	**Return on Equity**	-0.68%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Smart Meter
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 7,831	$ 146	$ 7,977
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	7,831	146	7,977
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	-	-	-
10	Admin & gen expense	7,570	-	7,570
11	Depreciation - accrual	129	-	129
12	Amortization	(377)	-	(377)
13	Taxes other than income	443	9	451
14	Operating expense before tax	7,765	9	7,773
15	Operating income before tax	66	137	204
	Income taxes			
16	Federal income tax - current	(153)	43	(109)
17	State income tax - current	(48)	14	(35)
18	Deferred income tax - federal	209	-	209
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	8	57	65
22	Total operating expenses	7,772	66	7,838
23	**Operating income**	$ 58	$ 80	$ 139
24	**Rate Base**	1,723		1,723
25	**Rate of Return overall**	3.39%		8.05%
26	**Return on Equity**	1.56%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Total Distribution
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ 252,990	$ 140,339	$ 393,329
2	STAS revenue	-	-	-
3	Sales for resale	15	-	15
4	Other operating revenue	19,328	-	19,328
5	Total operating revenue	272,333	140,339	412,672
	Operating expenses			
6	PTC	52	-	52
7	Distribution	52,939	-	52,939
8	Customer accounts	18,793	-	18,793
9	Customer service & info	15,035	-	15,035
10	Admin & gen expense	16,919	-	16,919
11	Depreciation - accrual	69,017	-	69,017
12	Amortization	11,418	-	11,418
13	Taxes other than income	21,106	8,280	29,386
14	Operating expense before tax	205,277	8,280	213,557
15	Operating income before tax	67,056	132,059	199,115
	Income taxes			
16	Federal income tax - current	20,141	41,603	61,745
17	State income tax - current	6,387	13,193	19,580
18	Deferred income tax - federal	10,581	-	10,581
19	Deferred income tax - state	-	-	-
20	Investment tax credit	(308)	-	(308)
21	Total tax expense	36,801	54,796	91,597
22	Total operating expenses	242,079	63,076	305,155
23	**Operating income**	$ 30,254	$ 77,263	$ 107,517
24	**Rate Base**	1,335,350		1,335,350
25	**Rate of Return overall**	2.27%		8.05%
26	**Return on Equity**	-0.68%		10.90%

Metropolitan Edison Company
Summary of Revenue Requirements
Universal Service Cost Rider
$000

Line No.	Description	Budget as Adjusted	Revenue Adjustment Required	Allowable Revenue
		(1)	(2)	(3)
	Operating revenues			
1	Retail sales	$ 28,882	$ -	$ 28,882
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	28,882	-	28,882
		-		
	Operating expenses	-		
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	24,409	-	24,409
10	Admin & gen expense	-	-	-
11	Depreciation - accrual	-	-	-
12	Amortization	3,164	-	3,164
13	Taxes other than income	1,749	-	1,749
14	Operating expense before tax	29,321	-	29,321
		-		
15	Operating income before tax	(440)	-	(440)
		-		
	Income taxes	-		
16	Federal income tax - current	(139)	-	(139)
17	State income tax - current	(44)	-	(44)
18	Deferred income tax - federal	-	-	-
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	(182)	-	(182)
		-		
22	Total operating expenses	29,139	-	29,139
23	**Operating income**	$ (257)	$ -	$ (257)

Metropolitan Edison Company
Summary of Revenue Requirements
Storm Damage Rider
$000

Line No.	Description	Budget as Adjusted (1)	Revenue Adjustment Required (2)	Allowable Revenue (3)
	Operating revenues			
1	Retail sales	$ -	$ -	$ -
2	STAS revenue	-	-	-
3	Sales for resale	-	-	-
4	Other operating revenue	-	-	-
5	Total operating revenue	-	-	-
	Operating expenses			
6	PTC	-	-	-
7	Distribution	-	-	-
8	Customer accounts	-	-	-
9	Customer service & info	-	-	-
10	Admin & gen expense	-	-	-
11	Depreciation - accrual	-	-	-
12	Amortization	-	-	-
13	Taxes other than income	-	-	-
14	Operating expense before tax	-	-	-
15	Operating income before tax	-	-	-
	Income taxes			
16	Federal income tax - current	-	-	-
17	State income tax - current	-	-	-
18	Deferred income tax - federal	-	-	-
19	Deferred income tax - state	-	-	-
20	Investment tax credit	-	-	-
21	Total tax expense	-	-	-
22	Total operating expenses	-	-	-
23	**Operating income**	$ -		$ -

Metropolitan Edison Company
Normalization Adjustment No. 1
$000

Adjustment of Base Operating Revenues

To adjust base operating revenues (1) for changes in the number of customers, (2) to roll in State Tax Adjustment Surcharge ("STAS") revenues into base rates, (3) to adjust for energy efficiency and behind the meter generation, (4) to adjust for other revenues and (5) to eliminate unbilled revenues. The adjustment for unbilled revenues is supported by Mr. R. A. D'Angelo. Adjustments (1) through (4) are supported by Mr. K. M. Siedt.

Line No.	Description	Amount (1)	Amount (2)
1	Base revenues per books for the 12 months ending 3/31/2014		$ 741,232
	Normalizing adjustments:		
2	Customers - increase to yr end level	$ 677	
	Specific adjustments		
3	Roll-in of STAS		
4	Adjust for Energy Efficiency and Behind the Meter Generation	(10,018)	
5	Adjust for Other Revenues	-	
6	Eliminate unbilled revenues	(3,212)	
7	Total	$ (13,230)	
8	Normalizing adjustment (Lines 2+7)		(12,553)
9	Base revenues per books for the 12 months ending 3/31/2014, as adjusted		$ 728,679

Metropolitan Edison Company
Normalization Adjustment No. 2
$000

Adjustment of State Tax Adjustment Surcharge Revenues

To remove state tax adjustment surcharge ("STAS") revenues. Normalized STAS revenues are being rolled into base rates.

Line No.	Description	Amount (1)
1	STAS revenue per books for the 12 months ended 3/31/2014	$ (2,123)
2	Eliminate per budget STAS	2,123
3	Other operating revenue per books for the 12 months ended 3/31/2014, as adjusted	$ -

Metropolitan Edison Company
Normalization Adjustment No. 3
$000

Adjustment of Other Operating Revenues

To adjust other operating revenue to eliminate non-jurisdictional transmission revenues.

Line No.	Description	Amount (1)
1	Other operating revenue per books for the 12 months ended 3/31/2014	$ 70,921
2	Eliminate non-jurisdictional transmission revenues	(56,257)
3	Other operating revenue per books for the 12 months ended 3/31/2014, as adjusted	$ 14,664

Metropolitan Edison Company
Normalization Adjustment No. 4
$000

Adjustment of Distribution Expense

To adjust distribution payroll expense to reflect year end wage and employee levels, to adjust service company distribution payroll expense to reflect year end wage and employee levels, eliminate non-jurisdictional transmission expense and to include the distribution portion of the amortization of gains or losses to reacquired debt. The plant and labor allocation factors used in this normalization adjustment are supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	Amount (2)
1	Distribution expense per books for the 12 months ended 3/31/2014		$ 67,795
2	Distribution payroll expense adjustment to reflect year end employee levels, and ongoing wage and salary rates (Supporting Schedule No. 1, Line 12, Column 1)	$ 285	
3	Service Company Distribution payroll expense adjustment allocated to Met-Ed to reflect year end employee levels, and ongoing wage and salary rates (Supporting Schedule No. 1, Line 21, Column 1)	97	
4	Eliminate non-jurisdictional transmission expense	(9,174)	
5	Amortization of (gain) or loss on reacquired debt	$ 2,671	
6	Allocation ratio based on distribution plant	77.70%	
7	Distribution portion of (gain) or loss	$ 2,075	
8	Total normalizing adjustment (Lines 2 + 3 + 4 + 7)		(6,717)
9	Distribution expense per books for the 12 months ended 3/31/2014, as adjusted		$ 61,078

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 4
($000)

Adjustment to Payroll Expense to Reflect Year End Employee Levels and Wage Rates

Line No.	Description		Amount (1)	Amount (2)
1	Total payroll per books for the 12 months ended 3/31/2014 (Exhibit RAD-27)			$ 64,937
	Bargaining			
2	Straight time per books for the 12 months ended 3/31/2014		$ 33,939	
3	Straight time 3% increase effective 5/1/2014 (Line 2 x 3%)		1,018	
	Non-Bargaining			
4	Straight time per books for April 1 2013 through February 28, 2014		13,533	
5	Straight time 3% increase effective 9/1/2013 (Line 4 x 3%)		406	
6	Total company payroll adjustment (Line 3 + Line 5)			1,424
7	O&M allocation %		39.67%	
8	O&M payroll adjustment (Line 6 X Line 7)		$ 565	
9	Total Payroll as adjusted (Line 1 + Line 6)			$ 66,361
	Allocation of payroll adjustment:			
10	Price to Compare	0.00%	$ -	
11	Transmission	8.91%	50	
12	Distribution	50.40%	285	
13	Customer accounts	17.72%	100	
14	Customer service	8.42%	48	
15	Administrative and general	14.55%	82	
16	Total	100%	$ 565	
	Service Company (Exhibit RAD-25)			
17	Straight time per books for April 1, 2013 through February 28, 2014		$ 14,361	
18	Straight time 3% increase effective 9/1/2013 (Line 17 x 3%)		431	
	Allocation of Service Company payroll adjustment (Exhibit RAD-25):			
19	Price to Compare	1.03%	$ 4	
20	Transmission	6.20%	27	
21	Distribution	22.45%	97	
22	Customer accounting and Information	31.68%	136	
23	Administrative and general	38.64%	166	
24	Total	100%	$ 431	

Metropolitan Edison Company
Normalization Adjustment No. 5
$000

Adjustment of Customer Accounts Expense

To adjust customer account expense to reflect year end wage and employee levels, increased costs associated with added customers, and interest on customer deposits.

Line No.	Description	Amount (1)	Amount (2)
1	Customer Account expense per books for the 12 months ended 3/31/2014		$ 24,842
2	Customer Account payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates (Normalizing Adjustment No. 4, Supporting Schedule No. 1, Line 13, Column 1)	$ 100	
3	Service Company customer account payroll expense adjustment allocated to Met-Ed to reflect year end employee levels and ongoing wage & salary rates (Normalizing Adjustment No. 4, Supporting Schedule No. 1, Line 22, Column 1)	136	
4	Increased O&M costs associated with increased number of customers in normalized revenue levels (Supporting Schedule 1, Line 10)	12	
5	Interest on customer deposits (Supporting Schedule 2, Line 3)	1,287	
6	Total normalizing adjustment (Lines 2 + 3 + 4 + 5)		1,536
7	Customer Account expense per books for the 12 months ended 3/31/2014, as adjusted		$ 26,378

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 5
($000)

Adjustment of Other O&M Costs Associated with Serving New Customers

In association with the additional revenues from added customers reflected in Adjustment No. 1, there is also a cost associated with serving those customers. The Commission has previously recognized this and approved an adjustment to customer accounts expense for this increased cost. This cost is estimated by determining the ratio of non-payroll customer account expense to distribution revenues from customers and applying this ratio to the additional revenue received from increased customers. The distribution revenue is supported by Mr. K. M. Siedt.

Line No.	Description	Amount
		(1)
	Customer Account Expense Excluding Labor and Uncollectible	
1	Customer Account expense per books for the 12 months ended 3/31/2014	$ 24,842
2	Less: Distribution uncollectible expense	(14,346)
3	Less: Labor expense	(5,879)
4	Customer Account expense excluding labor and uncollectible expense	$ 4,617
	Total Base Revenue	
5	Distribution revenues per budget	$ 254,499
6	Late payment charges per books	3,583
7	Total	$ 258,082
8	Ratio of customer account expense to total revenue (Line 4 / Line 7)	1.79%
9	Revenue from added customers (Adjustment No. 1, Line 2)	$ 677
10	Additional expense from added customers (Line 8 x Line 9)	$ 12

Metropolitan Edison Company
Supporting Schedule No.2 to Normalizing Adjustment No. 5
($000)

Adjustment to Allow for Interest Expense on Customer Deposits

Customer deposits are included in rate base as a deduction, since these are funds supplied by customers to the company. Interest paid to customers on these deposits correspondingly has been recognized by the Commission as a expense when setting rates.

Line No.	Description	Amount (1)
1	Customer deposits included in rate base (Exhibit RAD-1 Column 1, Line 14)	$ 21,452
2	Interest rate on deposits	6%
3	Interest expense on customer deposits	$ 1,287

Metropolitan Edison Company
Normalization Adjustment No. 6
$000

Adjustment of Customer Service and Information Expense

To adjust customer service and information expense to reflect year end wage and employee levels.

Line No.	Description	Amount (1)	Amount (2)
1	Customer Service expense per books for the 12 months ended 3/31/2014		$ 40,005
2	Customer Service payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 14, Column 1)	$ 48	
3	Total normalizing adjustment		48
4	Customer Service expense per books for the 12 months ended 3/31/2014, as adjusted		$ 40,053

Metropolitan Edison Company
Normalization Adjustment No. 7
$000

Adjustment of Administrative and General Expense

To adjust Administrative and General expenses to reflect employee benefits expenses at year end personnel and wage levels, OPEB expense at the service cost level, pension expense to the ten year cash level, amortization of rate case expenses, the elimination of non-jurisdictional administrative and general expenses, and the elimination of distribution uncollectible accounts expense. Ms. L.W. Gifford supports the distribution uncollectible expenses. Hillary Stewart supports the non-jurisdictional expense allocation factor.

Line No.	Description	Amount (1)	Amount (2)
1	Administrative & general expense per books for the 12 months ended 3/31/2014		$ 6,525
2	Administrative & general expenses related to EE&C	$ (21,093)	
3	Administrative & general expenses related to Smart Meters	(7,570)	
4	Adjustment to administrative & general expenses	(28,663)	
5	Net administrative & general expenses related to distribution	(22,138)	
6	Administrative & general payroll expense adjustment to reflect year end employee levels and ongoing wage & salary rates (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 15, Column 1)	82	
7	Service Company Administrative & general payroll expense adjustment allocated to Met-Ed to reflect year end employee levels and ongoing wage & salary rates (Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 23, Column 1)	166	
8	Adjust OPEB expense to service cost level (Normalization Adjustment No. 7, Supporting Schedule No. 1, Line 12, Col. 1)	9,864	
9	Adjust pension expense to ten year cash level (Supporting Schedule No. 2, Line 18, Col. 3)	21,891	
10	Adjust employee benefit costs (Supporting Schedule No. 3, Line 8, Column 3)	295	
11	Subtotal of adjustments (Lines 6 + 7 + 8 + 9 + 10)		32,299
12	Administrative and general expense, adjusted	$ 10,161	
13	Non-jurisdictional expense allocation factor	10.43%	
14	Non-jurisdictional administrative and general expense		(1,060)
15	Rate case expenses to be incurred during current rate proceeding (Exhibit RAD-23)	$ 495	
16	Recovery period - years	2	
17	Annual amount (Line 15 / Line 16)		$ 248
18	Total normalizing adjustment (Lines 11 + 14 + 17)		$ 31,487
19	Administrative and general expense per books for the 12 months ended 3/31/2014, as adjusted		$ 38,012

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 7
$000

Adjustment for OPEB Expense

Budgeted OPEB expense consists of the current service cost, adjustments to prior years' service costs, and the financing component. This schedule adjusts the total budgeted expense amounts to the service cost. The service cost represents the actuarial present value of benefit liabilities accrued under the plan benefit formula for services rendered during the test year. Inclusion of the service cost in rates provides for recovery of the current cost of benefits earned by plan participants. Any excess or shortfall related to the expected return on plan assets are not included because their inclusion would artificially reduce or increase total costs and result in the recovery of more or less than the actual normal cost of service. The adjustment for OPEB expense to the current service cost amount was adopted by the Commission at Nos. Docket R-00061366 and R-00061367

Line No.	Description	O&M (1)	Capital (2)	Total (3)
1	O&M - Capital allocation ratios	39.67%	60.33%	100.00%
2	Company OPEB expense included on books	$ (8,758)	$ (13,320)	$ (22,078)
3	FirstEnergy Service Corp. OPEB expense	$ (16,375)	$ (24,904)	$ (41,279)
4	Allocation ratio	4.86%	4.86%	4.86%
5	Allocated FirstEnergy Service Corp. OPEB expense included on books (Line 3 X Line 4)	$ (796)	$ (1,210)	$ (2,006)
6	Total OPEB expense included on books (Line 2 + Line 5)	$ (9,554)	$ (14,530)	$ (24,084)
7	Service cost for company OPEB expense	$ 289	$ 440	$ 729
8	Service cost for FirstEnergy Service Corp. OPEB expense	$ 439	$ 668	$ 1,107
9	Allocation ratio	4.86%	4.86%	4.86%
10	Allocated FirstEnergy Service Corp. service cost (Line 8 x Line 9)	$ 21	$ 33	$ 54
11	Total OPEB service cost (Lines 7 + 10)	$ 310	$ 473	$ 783
12	Adjustment to set OPEB expense at ongoing service cost level (Lines 11 - 6)	$ 9,864	$ 15,003	$ 24,867

Metropolitan Edison Company
Supporting Schedule No. 2 to Normalizing Adjustment No. 7
$000

Adjustment for Pension Expense

To adjust budget pension expense to a ten year historical average level of actual cash contributions under the methodology that was adopted by the Commission at Docket Number R-00061366 and R-00061367.

Line No.	Description	Amount (1) Total	(2) O&M %	(3) O&M
	Company Cash Contributions			
1	2004 Cash Pension Contribution	$ 38,823	56.52%	$ 21,943
2	2005 Cash Pension Contribution	35,912	56.52%	20,297
3	2007 Cash Pension Contribution	11,012	55.42%	6,103
4	2009 Cash Pension Contribution	123,521	50.49%	62,366
5	2011 Cash Pension Contribution	35,000	45.09%	15,782
6	Total Company Cash Pension Contributions	$ 244,268		$ 126,490
	FirstEnergy Service Company Cash Contributions			
7	2004 Pension Contribution	$ 91,633		
8	2004 Company Allocation Factor	8.91%		
9	2004 Service Company Pension Contribution allocated to the Company	$ 8,165	56.52%	$ 4,615
10	2007 Pension Contribution	$ 27,468		
11	2007 Company Allocation Factor	11.29%		
12	2007 Service Company Pension Contribution allocated to the Company	$ 3,101	55.42%	1,719
13	Total FirstEnergy Service Company Cash Pension Contributions allocated to the Company (Line 9 + Line 12)	$ 11,266		$ 6,333
14	Total Pension cash contributions (Line 6 + Line 13)	$ 255,534		$ 132,824
15	Average	10		10
16	Pension expense cash contribution, amortized over 10 years	$ 25,553		$ 13,282
17	O&M Pension Expense included on the books			(8,609)
18	Adjustment to Pension Expense (Line 16 - Line 17)			$ 21,891

Metropolitan Edison Company
Supporting Schedule No. 3 to Normalizing Adjustment No. 7
$000

Adjustment to Employee Benefit Expense to Reflect Year End Employee Levels and Ongoing Wage Rates

Normalization Adjustment No. 4, Supporting Schedule No. 1, Line 8 increases the O&M payroll expense. Associated with that increase are employee benefits charged to Administrative and General expense. This adjustment computes the added benefit costs on a normalized basis.

Employee benefits applicable to operating expenses:

Line No.		Effective Rate (a)	Payroll Adjustment		Benefit Adjustment
		(1)	(2)		(3) = (1) X (2)
1	Workers compensation	0.645%	$ 565	(b)	$ 4
2	Pension costs	37.616%	$ 565	(b)	213
3	OPEB costs	1.123%	$ 565	(b)	6
4	Life insurance	0.065%	$ 565	(b)	-
5	Medical insurance	9.415%	$ 565	(b)	53
6	Savings Plan	2.037%	$ 565	(b)	12
7	Other	1.177%	$ 565	(b)	7
8	Total increase due to payroll adjustment				$ 295

(a) Summary of effective employee benefit rates based on total payroll for the 12 months ending 3/31/14

	Total Amount	Total Payroll	Effective Rate
Workers compensation	$ 419	$ 64,937	0.645%
Pension costs - normalized basis	24,427	64,937	37.616%
OPEB costs - service cost	729	64,937	1.123%
Life insurance	42	64,937	0.065%
Medical insurance	6,114	64,937	9.415%
Savings Plan	1,323	64,937	2.037%
Other	764	64,937	1.177%

(b) Adjustment No. 4, Supporting Schedule No. 1, Line 8.

Metropolitan Edison Company
Normalization Adjustment No. 8
$000

Adjustment of Depreciation Expense

To adjust budgeted depreciation expense to reflect average remaining life rates on adjusted rate base, to eliminate non-jurisdictional expense, and to adjust cost of removal/ salvage expense to a five year average amount, according to prior commission practice and the adjustment of legacy meters. The plant allocation factor used in this normalization adjustment are supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	(2)	(3)	(4)
1	Depreciation expense per books for the 12 months ended 3/31/2014				$ 58,193
2	Cost of removal/salvage expense per budget for the 12 months ending 3/31/2014 (Exhibit RAD-30)		$ 10,222		
3	Depreciation accrual per books (Line 1 - Line 2)		$ 47,971		
4	Jurisdictional depreciation expense accrual on adjusted rate base at average remaining life rates (Exhibit RAD-53, page 2)		44,820		
5	Adjustment for average remaining life accrual for jurisdictional plant, (Line 4 - Line 3).			(3,151)	
6	Cost of removal/salvage expense per budget for the 12 months ending 3/31/2014 (Exhibit RAD-30)		$ 10,222		
	Cost of removal and salvage (Exhibit RAD-30)				
7	4/1/2009 - 3/31/2010	$ 17,539			
8	4/1/2010 - 3/31/2011	7,101			
9	4/1/2011 - 3/31/2012	17,511			
10	4/1/2012 - 3/31/2013	28,248			
11	4/1/2013 - 3/31/2014	10,222			
12	Total	$ 80,620			
13	Five year average (Line 12 / 5)		16,124		
14	Allocation ratio based on jurisdictional plant		77.70%		
15	Jurisdictional cost of removal/salvage expense to a jurisdictional five year average (Line 13 x 14)		12,528		
16	Adjustment of jurisdictional cost of removal/salvage expense to a jurisdictional five year average (Line 15 - Line 6)			2,306	
17	Adjustment for acceleration of legacy meters (Adj. 8 Sched 1, Line 6)			11,668	
18	Total normalizing adjustment (Lines 5 + 16 + 17)				10,824
19	Depreciation expense per books for the 12 months ended 3/31/2014, as adjusted				$ 69,017

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalizing Adjustment No. 8
$000

Adjustment for Acceleration for legacy meters

To accelerate recovery of legacy meters to fully recover all legacy meter costs over 5 years.

Line No.	Description	Amount (1)	Amount (2)
1	Legacy meters per budget for the 12 months ended 3/31/2014	$ 66,795	
2	Depreciation reserve per budget for the 12 months ending 3/30/2014	12,085	
3	Net legacy meters per budget for the 12 months ended 3/31/2014	$ 54,710	
4	Net estimated cost of removal and salvage	3,631	
5	Net legacy meters	$ 58,341	
6	Annual amortization over a 5 year amortization period		$ 11,668

Metropolitan Edison Company
Normalization Adjustment No. 9
$000

Adjustment of Amortization Expense

To include the amortization of deferred storm damage balances for Winter Storm Nika, approved at Docket No. P-2014-2412229, Hurricane Sandy, approved at Docket No. P-2013-2351260, and distribution non-capital storm expenses that exceeded 125% of storm costs included in base rates between the period of February 25, 2011 through September 30, 2012 as a result of the FirstEnergy and Allegheny Merger approved at Docket Nos. A-2010-2176520 and A-2010-2176732, including but not limited to Hurricane Irene, the October 2011 snowstorm, and Tropical Storm Lee. In addition, accretion expenses are removed.

Line No.	Description	Amount (1)	Amount (2)
1	Amortization expense per books for the 12 months ended 3/31/2014		$ 12,250
2	Deferred Nika storm damage	$ 13,327	
3	Deferred Sandy storm damage	21,497	
4	Merger storm deferral	30,140	
5	Total deferred storms (Lines 2+3+4)	$ 64,964	
6	Amortized over 3 years	3	
7	Annual Amortization	21,655	
8	Remove accretion expense	(58)	
9	Total normalization		21,597
10	Amortization expense per books for the 12 months ended 3/31/2014, as adjusted		$ 33,847

Metropolitan Edison Company
Normalization Adjustment No. 10
$000

Adjustment of Taxes Other Than Income

To adjust gross receipts tax expense to reflect normalized sales revenues, to adjust payroll tax expenses for normalized payroll and employee expenses. The non-jurisdictional allocation factor is supported by Ms. H. E. Stewart.

Line No.	Description	Amount (1)	Amount (2)	Amount (3)
1	Taxes Other Than Income per books for the 12 months ended 3/31/2014			$ 50,525
2	Federal and State payroll taxes on books	$ 4,819		
3	Non-jurisdictional percent	10.43%		
4	Eliminate non-jurisdictional payroll taxes		$ (503)	
5	Capital Stock Tax included on books	$ 376		
6	PURTA tax on books	1,882		
7	Real Estate tax on books	134		
8	Total Other taxes	$ 2,392		
9	Non-jurisdictional percent	22.30%		
10	Eliminate non-jurisdictional taxes		(534)	
	Gross Receipts Tax			
11	Normalized sales revenues (Exhibit RAD-2, page 1, Col. 3)	$ 728,679		
12	Gross receipts tax @ 5.9%	42,992		
13	Gross receipts tax included on books	43,296		
14	Adjustment for gross receipts tax at normalized revenue level (Line 12 - Line 13)		(304)	
15	Adjustment for payroll taxes on normalized payroll, Supporting Schedule No. 1, Line 8		42	
16	Total normalizing adjustment (Lines 4 + 10 + 14 + 15)			(1,298)
17	Taxes other than income per books for the 12 months ended 3/31/2014, as adjusted			$ 49,227

Metropolitan Edison Company
Supporting Schedule No.1 to Normalizing Adjustment No. 10
$000

Adjustment to Taxes Other Than Income to reflect changes in payroll taxes.

Normalization adjustments have been made to normalize O&M payroll expense. Associated with those payroll normalizations are changes in FICA tax amounts.

Line No.	Description	Amount (1)
1	Total payroll per books for the 12 months ended 3/31/2014 Normalization Adjustment No. 4, Schedule 1, Line 1, Col 2	$ 64,937
2	Total payroll tax included on books	4,819
3	Effective payroll tax rate (Line 2 / Line 1)	7.421%
4	Total payroll as adjusted, Normalization Adjustment No. 4, Schedule 1, Line 9, Col. 2	$ 66,361
5	Payroll tax on normalized payroll (Line 3 X Line 4)	$ 4,925
6	Total Company payroll tax adjustment (Line 5 - Line 2)	$ 106
7	O&M Allocation percentage	39.67%
8	Adjustment for payroll tax (Line 6 x Line 7)	$ 42

Metropolitan Edison Company
Normalization Adjustment No. 11
$000

Computation of Federal & State Income Taxes - Normalized

Line No.	Description	Total Company Calculated Taxes (1)	Distribution Calculated Taxes (2)	PTC Calculated Taxes (3)	Universal Service Calculated Taxes (4)	Energy Efficiency Calculated Taxes (5)	Smart Meter Rider Calculated Taxes (6)	DSS Calculated Taxes (7)	Solar Calculated Taxes (8)	NUG Charge Calculated Taxes (9)	Storm Rider Calculated Taxes (10)	CEC Rider Calculated Taxes (11)
1	Total operating revenue	$ 769,405	$ 264,502	$ 400,758	$ 28,882	$ 29,531	$ 7,831	$ 26,795	$ 2,651	$ 8,194	$ -	$ 261
2	Less: Total O& M Expense	547,893	96,167	380,800	24,409	21,093	7,570	16,042	1,522	$ -	$ -	$ 290
3	Depreciation - accrual	56,488	56,359	-	-	-	129	-	-	-	-	-
4	Average net salvage	12,528	12,528	-	-	-	-	-	-	-	-	-
5	Amortization	33,847	11,795	(2,118)	3,164	6,659	(377)	6,232	938	7,573	-	(19)
6	Taxes other than income taxes	49,227	20,663	22,492	1,749	1,779	443	1,305	156	621	-	20
7	Total deductions	$ 699,984	$ 197,513	$ 401,175	$ 29,321	$ 29,531	$ 7,765	$ 23,579	$ 2,615	$ 8,194	$ -	$ 291
8	Net operating income before income taxes	$ 69,422	$ 66,989	$ (416)	$ (440)	$ -	$ 66	$ 3,216	$ 36	$ -	$ -	$ (30)
9	Less: Interest Charges (A)	34,799	34,754	-	-	-	45	-	-	-	-	-
10	Net income before income taxes	$ 34,623	$ 32,235	$ (416)	$ (440)	$ -	$ 21	$ 3,216	$ 36	$ -	$ -	$ (30)
	Adjustments to taxable income:											
11	Book Average net salvage	12,528	12,528	-	-	-	-	-	-	-	-	-
12	Adj. of book depreciation to tax basis (B)	$ 2,344	$ 2,850	$ -	$ -	$ -	$ (506)	$ -	$ -	$ -	$ -	$ -
13	Tax cost of removal/salvage	(5,087)	(5,087)	-	-	-	-	-	-	-	-	-
14	Adjust cash pension	21,891	21,891	-	-	-	-	-	-	-	-	-
15	Net adjustment	31,677	32,183	-	-	-	(506)	-	-	-	-	-
16	Income subject to state income tax	66,299	64,418	(416)	(440)	-	(485)	3,216	36	-	-	(30)
17	State income tax @ 9.99%	$ 6,623	$ 6,435	$ (42)	$ (44)	$ -	$ (48)	$ 321	$ 4	$ -	$ -	$ (3)
18	Taxes as budgeted	5,701	5,701	-	-	-	-	-	-	-	-	-
19	Adjustment to state income tax	$ 922	$ 734	$ (42)	$ (44)	$ -	$ (48)	$ 321	$ 4	$ -	$ -	$ (3)
20	Income subject to federal income tax	$ 59,676	$ 57,983	$ (375)	$ (396)	$ -	$ (436)	$ 2,895	$ 32	$ -	$ -	$ (27)
21	Federal income tax @ 35%	$ 20,887	$ 20,294	$ (131)	$ (139)	$ -	$ (153)	$ 1,013	$ 11	$ -	$ -	$ (9)
22	Taxes as budgeted	28,956	28,956	-	-	-	-	-	-	-	-	-
23	Adjustment to federal income tax	$ (8,069)	$ (8,662)	$ (131)	$ (139)	$ -	$ (153)	$ 1,013	$ 11	$ -	$ -	$ (9)
	(A) Computation of Interest charges											
	Total rate base	$ 1,335,350	$ 1,333,627	$ -	$ -	$ -	$ 1,723	$ -	$ -	$ -	$ -	$ -
	Debt ratio	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%	50.04%
	Cost of debt	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%
	Interest expense	$ 34,799	$ 34,754	$ -	$ -	$ -	$ 45	$ -	$ -	$ -	$ -	$ -
	(B) Adjustment of book depreciation to tax basis:											
	Tax depreciation	54,144	53,509	-	-	-	635	-	-	-	-	-
	Book depreciation	56,488	56,359	-	-	-	129	-	-	-	-	-
	Depreciation adjustment	(2,344)	(2,850)	-	-	-	506	-	-	-	-	-

Metropolitan Edison Company
Supporting Schedule No. 1 to Normalization Adjustment No. 11
$000

Computation of Federal & State Income Taxes - Normalized

To (1) split the tax depreciation into cost of removal, smart meter, and distribution components, and (2) calculate the jurisdictional allocation.

Line No.	Description	Amount (1)	(2)	(3)
1	Tax depreciation expense per books	$ 76,048		
2	Cost of removal / salvage	6,547	77.70%	5,087
3	Smart meter tax depreciation	635	100.00%	635
4	Distribution tax deprecation	$ 68,866	77.70%	53,509
5	Total tax depreciation			$ 54,144

Metropolitan Edison Company
Normalization Adjustment No. 12
$000

Adjustment of Provision for Deferred Income Taxes

This adjustment to the Provision for Deferred Income Taxes reflects (1) the adjustment of Federal deferrals to reflect year-end plant. All state deferred taxes associated with liberalized depreciation have been eliminated.

Line No.	Description	Provision for Deferred Taxes - Net	
		Federal	State
		(1)	(2)
1	Deferred taxes per books, 12 months ended 3/31/2014	$ (59,116)	$ -
2	Deferred taxes - liberalized depreciation (Exhibit RAD-41, page 19)	13,618	-
3	Jurisdictional allocation factor	77.70%	77.70%
4	Jurisdictional deferred taxes - liberalized depreciation (Line 2 X Line 3)	10,581	-
5	Adjustment to deferred tax expense (Line 4 - Line 1)	69,697	-
6	Deferred tax expense per books for the 12 months ended 3/31/2014, as adjusted	$ 10,581	$ -

Metropolitan Edison Company
Normalization Adjustment No. 13
$000

Adjustment of Investment Tax Credit

This adjustment is to eliminate the non-jurisdictional portion of investment tax credit adjustments.

Line No.	Description	Amount (1)	Amount (2)
1	Investment tax credit adjustments per books, 12 months ended 3/31/2014		$ (397)
2	Jurisdictional allocation factor	77.70%	
3	Jurisdictional investment tax credit (Line 1 x Line 2)	$ (308)	
4	Adjustment to investment tax credit expense (Line 3 - Line 1)		89
5	Adjustment to investment tax credit expense per books for the 12 months ended 3/31/2014, as adjusted		$ (308)

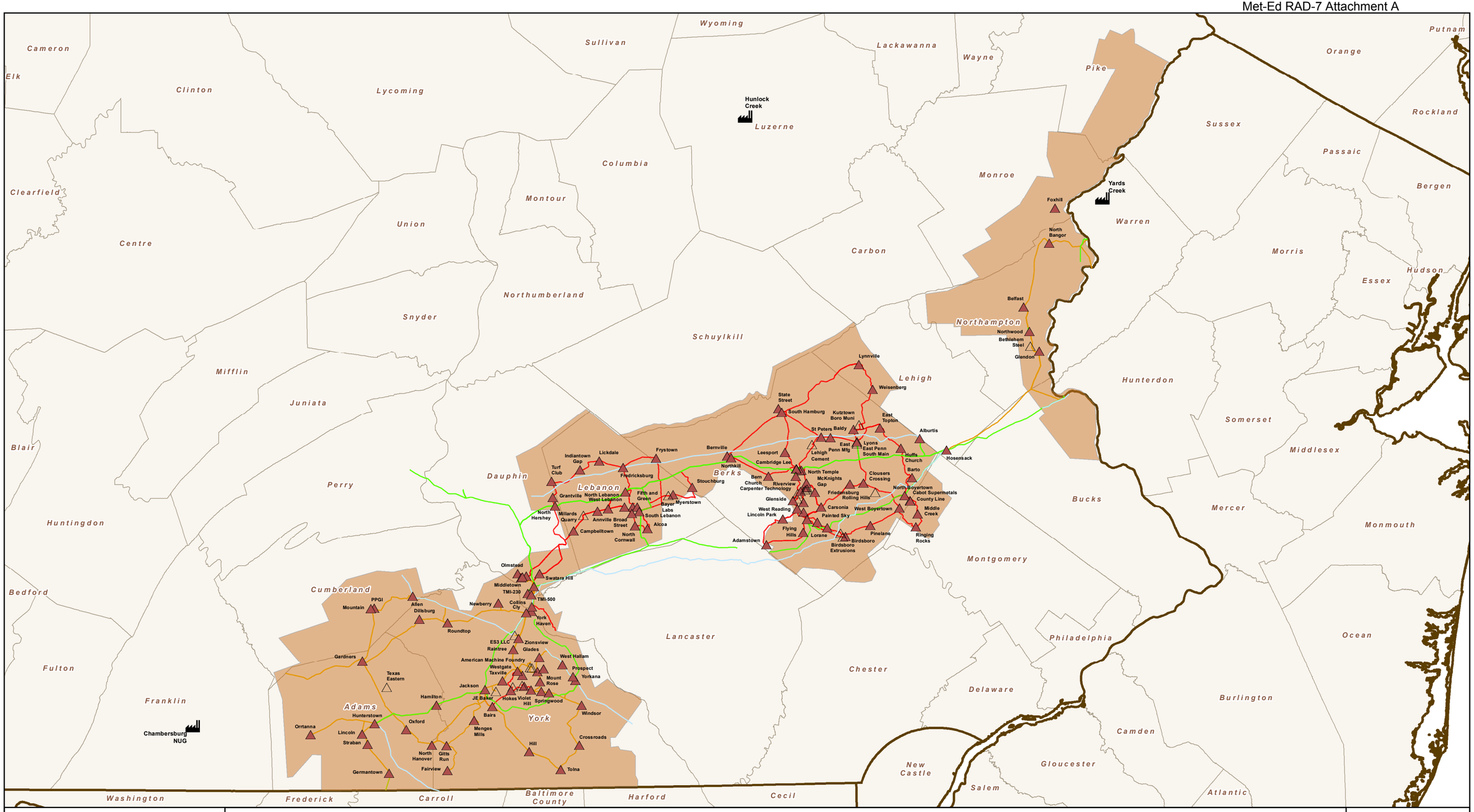
METROPOLITAN EDISON COMPANY

FILING REQUIREMENT I-B-3:

> "Provide an overall system map, including and labeling all generating plants, transmission substations—indicate voltage, transmission system lines—indicate voltage, and all interconnection points with other electric utilities, power pools, and other like systems."

RESPONSE:

See Met-Ed Exhibit RAD-7 Attachment A.



0 12.5 25 Miles

- Generation
- FE Owned Substation
- Customer Owned Substation
- Met-Ed

69 kV
115 kV
138 kV
230 kV
500 kV

Met-Ed Transmission System

N

Met-Ed®
A FirstEnergy Company

Created on 5/2/2014

Contains Privileged and Confidential Information and/or Critical Infrastructure Information
Do Not Release Pursuant to 18 C.F.R. § 388.12

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-A-1:

"Provide a schedule showing the test year rate base and rates of return at original cost less accrued depreciation under present rates and under proposed rates. Claims made on this schedule should be cross-referenced to appropriate supporting schedules."

RESPONSE:

See Met-Ed Exhibit RAD-1 for the fully projected future test year.

See Met-Ed Exhibit RAD-3 for the future test year.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-A-2:

"If the schedule provided in response to item 1, is based upon a future test year, provide a similar schedule which is based upon actual data for the 12-month period immediately prior to the test year."

RESPONSE:

See Met-Ed Exhibit RAD-5 for the historical test year.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-A-3:

"When a utility files a tariff stating a new rate based in whole or in part on the cost of construction, as defined in 66 Pa.C.S. § 1308(f) (relating to voluntary changes in rates), of an electric generating unit, the utility shall identify:

(a) The total cost of the generating unit
(b) The following costs:
    (1) The cost and quantity of each category of major equipment, such as switchgear, pumps or diesel generators and the like.
    (2) The cost and quantity of each category of bulk materials, such as concrete, cable and structural steel and the like. .
    (3) Manual labor. .
    (4) Direct and indirect costs of architect/engineering services. .
    (5) Direct and indirect costs of subcontracts or other contracts involving major components or systems such as turbines, generators, nuclear steam supply systems, major structures and the like.
    (6) Distributed costs.
(c) A cost increase of $5 million or more, including AFUDC, over the original utility estimates provided under 66 Pa.C.S. § 515(a) (relating to construction cost of electric generating units) and its causes.
(d) Compliance with subsections (a) and (b) will be identical in format and substance as that provided under 52 Pa. Code § 57.103 (relating to estimate of construction costs) for original cost estimates submitted under 66 Pa.C.S. § 515(a)."

RESPONSE:

Not applicable.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-B-1:

"If a claim is made for plant held for future use, supply the following:

a. A description of the plant or land site and its cost and any accumulated depreciation.
b. The expected date of use for each item claimed.
c. An explanation as to why it is necessary to acquire each item in advance of its date of use.
d. The data when each item was acquired.
e. The date when each item was placed in plant held for future use."

RESPONSE:

There is no rate base claim being made in this proceeding for plant held for future use.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-B-2:

> "If a claim is made for construction work in progress, provide a supporting schedule which sets forth separately, revenue-producing and nonrevenue producing amounts, and include, for each category a summary of all work orders, amounts expended at the end of the test year and anticipated in service dates. Indicate if the construction work in progress will result in insurance recoveries, reimbursements, or retirements of existing facilities. Describe in exact detail the necessity of each project claimed if not detailed on the summary page from the work order. Include final completion dates and estimated total amounts to be spent on each project."

RESPONSE:

Met-Ed is not making any rate base claim for construction work in progress.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-B-3:

"If a claim is made for materials and supplies or fuel inventory provide a supporting schedule for each claim showing the latest actual 13 monthly balances and showing in the case of fuel inventory claims, the type of fuel, and location, as in station, and the quantity and price claimed."

RESPONSE:

METROPOLITAN EDISON COMPANY

13 Month Book Balance of Materials and Supplies

Line No.	Month	Amount *(in thousands)*
1	April 1, 2013	$ 13,926,128
2	April 30, 2013	13,653,200
3	May 31, 2013	14,667,989
4	June 30, 2013	15,853,993
5	July 31, 2013	15,953,474
6	August 31, 2013	15,927,057
7	September 30, 2013	15,557,251
8	October 31, 2013	15,623,111
9	November 30, 2013	15,240,945
10	December 31, 2013	13,458,084
11	January 31, 2014	13,682,065
12	February 28, 2014	14,092,822
13	March 31, 2014	14,493,114
14	13 Period Average	$ 14,779,172

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-B-4:

> "If a claim is made for cash working capital provide a supporting schedule setting forth the method and all detailed data utilized to determine the cash working capital requirement. If not provided in the support data provide a lead-lag study of working capital, completed no more than 6 months prior to the rate increase filing."

RESPONSE:

See the Direct Testimony of Patricia Larkin, Met-Ed/Penelec/Penn Power/West Penn Statement No. 6.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-B-6:

"Explain in detail by statement or exhibit the appropriateness of additional claims or the use of a method not previously mentioned, in the claimed rate base."

RESPONSE:

The supporting schedules included in Met-Ed Exhibit RAD-1 explain the appropriateness of various items claimed in the rate base. Items not explained in supporting schedules to Met-Ed Exhibit RAD-1, or not mentioned in other responses to filing requirements are explained below:

1. Customer Deposits

Customer deposits are deducted from the rate base as they represent a source of non-investor supplied capital. Appropriate interest on such deposits has been included as a normalizing adjustment to the income statement.

2. Customer Advances for Construction

In accordance with the practice followed in prior rate filings and accepted by Commission Orders, the Company reduces rate base by the amount of customer advances for construction at the end of the test year.

3. Operating Reserves

The Company has adopted a partial self-insurance concept for general and automotive liability insurance, property insurance and a long-term disability plan. The Company has also established an operating reserve for the purpose of providing a pension fund in addition to the normal funded plan. These operating reserves, net of applicable deferred taxes, reduce the Company's total rate base claim.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-C-1:

"Prepare a Statement of Income including:

(a) The book, or budgeted, statement for the test year.
(b) Adjustments to annualize and normalize under present rates, including an elimination of the effects on income of the energy cost rate and state tax adjustment surcharge.
(c) The income statement under present rates after adjustment.
(d) The adjustment for the revenue requested.
(e) The income statement under requested rates after adjustment.
(f) Each adjustment, including those relating to adjustment clauses, shall contain an explanation in sufficient clarifying detail to allow a reasonably informed person to understand the method and rationale of the adjustment."

RESPONSE:

Fully Projected Future Test Year

(a – f): See Met-Ed Exhibit RAD-2. Regarding part (b) pertaining to the annualization and normalization of revenues including applicable surcharges and tariff riders, these adjustments are supported in the Direct Testimony of Met-Ed Witness Kevin M. Siedt, Met-Ed Statement No. 4 and Met-Ed Exhibit KMS-1 Attachment A which accompanies his Direct Testimony.

Future Test Year

(a – f) See Met-Ed Exhibit RAD-4. Regarding part (b) pertaining to the annualization and normalization of revenues including applicable surcharges and tariff riders, these adjustments are supported in the Direct Testimony of Met-Ed Witness Kevin M. Siedt, Met-Ed Statement No. 4 and Met-Ed Exhibit KMS-1, Attachment B which accompanies his Direct Testimony.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-C-2:

"If the schedule provided in Filing Requirement II-C-1 is based upon budgeted data for a future test year, provide a similar schedule which is based upon actual data for the 12-month period immediately prior to the test year."

FILING REQUIREMENT II-C-1:

"Prepare a Statement of Income including:

(a) The book, or budgeted, statement for the test year.
(b) Adjustments to annualize and normalize under present rates, including an elimination of the effects on income of the energy cost rate and state tax adjustment surcharge.
(c) The income statement under present rates after adjustment.
(d) The adjustment for the revenue requested.
(e) The income statement under requested rates after adjustment.
(f) Each adjustment, including those relating to adjustment clauses, shall contain an explanation in sufficient clarifying detail to allow a reasonably informed person to understand the method and rationale of the adjustment."

RESPONSE:

(a – f): See Met-Ed Exhibit RAD-6. Regarding part (b) pertaining to the annualization and normalization of revenues including applicable surcharges and tariff riders, these adjustments are supported in the Direct Testimony of Met-Ed Witness Kevin M. Siedt, Met-Ed Statement No. 4 and Met-Ed Exhibit KMS-1, Attachment C which accompanies his Direct Testimony.

Metropolitan Edison Company
Comparative Income Statements

FERC Account		Twelve Months Ending April 30, 2016	March 31, 2015	Increase/ (Decrease)
Operating Revenues				
Electric Service Revenues				
440	Residential sales	$ 487,124	$ 495,246	$ (8,122)
442	Commercial sales	112,883	123,810	(10,927)
442	Industrial sales	51,258	50,866	392
444	Public street and highway lighting	5,410	5,141	269
445	Other sales to public authorities	-	-	-
447	Sale for resale	12,678	21,076	(8,398)
	Total electric service revenues	$ 669,354	$ 696,139	$ (26,785)
Other Electric Revenue				
450	Forfeited discounts	$ 3,229	$ 3,229	$ -
451	Miscellaneouse service revenues	1,903	1,903	-
454	Rent from electric property	19,477	19,477	-
456	Other electric revenues	47,656	47,885	(228)
	Total other electric revenues	$ 72,265	$ 72,494	$ (228)
	Total operating revenues	$ 741,619	$ 768,633	$ (27,014)
Operating Expenses				
401-2	Operation and maintenance expense			
	Power production expenses	$ 275,734	$ 320,216	$ (44,483)
	Transmission expenses	21,154	21,730	(577)
	Regional market expenses	54	50	4
	Distribution expenses	37,980	33,837	4,143
	Customer accounts expense	23,271	25,286	(2,015)
	Customer service & information expense	40,696	44,185	(3,488)
	Sales expenses	25	24	1
	Administrative & general expenses	41,116	37,806	3,310
	Subtotal	$ 440,030	$ 483,134	$ (43,104)
403	Depreciation expense	$ 59,721	$ 56,892	$ 2,829
404-5	Amortization and depletion of utility plant	4,710	2,681	2,029
406	Amortization and utility plant acq. adjustment	-	-	-
407	Amortization of property losses	-	-	-
407.3	Regulatory debits	22,920	24,410	(1,490)
407.4	Regulatory credits	15,407	(11,449)	26,856
408.1	Taxes other than income taxes	45,795	46,882	(1,086)
411.1	Accretion expense	49	62	(13)
411.8	Gains from disposition allowance	-	-	-
	Total operating expenses before federal and state income taxes	$ 588,632	$ 602,611	$ (13,980)
	Net operating income before income taxes	$ 152,987	$ 166,021	$ (13,034)
Income taxes				
409.1	Income taxes-federal	$ 39,423	$ 25,303	$ 14,121
409.1	Income taxes-state	-	-	-
410.1	Provision for deferred income taxes	49,263	67,085	(17,822)
411.1	Income taxes deferred in prior years-cr.	(42,966)	(39,764)	(3,202)
411.4	Investment tax credit adjustments-net	(364)	(364)	-
	Total income taxes	$ 45,356	$ 52,260	$ (6,903)
	Net operating income	$ 107,631	$ 113,762	$ (6,131)

Metropolitan Edison Company
Comparative Income Statements

FERC Account		Twelve Months Ending April 30, 2016	March 31, 2015	Increase/ (Decrease)
Other income				
415-16	Revenues from merchandising, jobbing and contract work	$ 2,808	$ 3,681	$ (872)
417	Revenues from non-utility operations	-	-	-
417.1	Expenses from non-utility operations	-	-	-
418	Nonoperating rental income	(17)	(17)	-
418.1	Equity in earnings of subsidiary companies	-	-	-
		-	-	-
419	Interest and dividend income	1,647	98	1,549
419.1	Allowance for funds used during construction	1,343	1,852	(509)
		-	-	-
421	Miscellaneous non-operating income	1,740	1,740	0
421.1	Gain on disposition of property	-	-	-
	Total other income	$ 7,522	$ 7,354	$ 168
	Gross income	$ 115,153	$ 121,115	$ (5,963)
Other Income Deductions				
421.2	Loss on disposition of property	$ -	$ -	$ -
425	Miscellaneous amortization	-	-	-
426	Other income deductions	146	146	0
	Total other income deductions	$ 146	$ 146	$ 0
Taxes Applicable to Other Income and Deductions				
408.2	Taxes other than income taxes	$ -	$ -	$ -
409.2	Income taxes - federal	-	-	-
409.2	Income taxes - state	-	-	-
410.2	Provision for deferred income taxes	-	-	-
411.2	Provision for deferred income taxes-cr.	-	-	-
	Total taxes on other income and deductions	$ -	$ -	$ -
Interest Charges				
427	Interest on long term debt	$ 51,862	$ 40,717	$ 11,145
428	Amortization of debt discount and expense	911	700	210
		-	-	-
428.1	Amortization of loss on reacquired debt	247	544	(297)
		-	-	-
429	Amortization of premium on debt credit	-	-	-
429.1	Amortization of gain on reacquired debt	(144)	(144)	-
430	Interest on debt to associated companies	8	1,036	(1,028)
431	Other interest expense	3,859	4,152	(293)
432	Allowance for borrowed funds used during construction - credit	(892)	(1,229)	338
		-	-	-
	Total interest charges	$ 55,852	$ 45,776	$ 10,076
	Income before extraordinary items	$ 59,155	$ 75,194	$ (16,039)
Extraordinary Items & Related Taxes				
434	Extraordinary income	$ -	$ -	$ -
435	Extraordinary deductions	-	-	-
409.3	Income taxes - Federal & other	-	-	-
	Extraordinary items after taxes	$ -	$ -	$ -
	Net income	$ 59,155	$ 75,194	$ (16,039)

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-1

"Provide a schedule showing all revenues and expenses for the test year and for the 12-month period immediately prior to the test year, together with an explanation for major variances between test year revenues and expenses and those for the previous 12-month period. Revenues and expenses shall be summarized by the major account categories listed below. If budgeted data for a future test year is not readily available by these categories, an analysis of the data for the 12-month period immediately prior to the future test year or for the most recent available calendar year may serve as the basis for ratably allocating the budgeted data into the account categories as follows:

OPERATING REVENUES

	Electric Revenues:
	Residential Sales
	Commercial Sales
	Industrial Sales
400	Public Street & Highway
	Lighting Sales
	Sales for Resale
	Total Other Electric Revenues
	Other Electric Revenues:
	Late Payment Charges
	Miscellaneous Service Revenues
	Rent from Electric Property
	Other Electric Revenues
	Total Other Electric Revenues
	Total Operating Revenues

OPERATING EXPENSES

	Operation and Maintenance Expenses
	Power Production Expenses:
	Fuel
401-2	Net Interchange
	Deferred Energy Costs
	Other
	Transmission Expenses
	Distribution Expenses
	Customer Service & Informational Expense
	Sales Expenses

	Administrative and General Expenses
	Total Operation & Maintenance Expenses
403	Depreciation Expenses
	Amortization of Net Salvage
	Nuclear Decommissioning Expense
407	Amortization of Property Losses
	Taxes Other Than Income Taxes
408	Total Operating Expenses Prior To Federal & State Income Taxes

OPERATING EXPENSES

	Operating Income Prior To Federal and State Income Taxes

FEDERAL AND STATE INCOME TAXES

	Federal Income Taxes
409	State Income Taxes
409	Deferred Federal Income Taxes
	Deferred State Income Taxes
	Investment Tax Credit Adjustments
411	Deferrals
	Amortization—Credit
	Other Income Tax Credits & Charges
	Total Federal and State Income Taxes
	Operating Income After Federal and State Income Taxes

OTHER INCOME AND DEDUCTIONS
OTHER INCOME

415-18	Non-utility Operating Income
419	Interest and Dividend Income
419	Allowance for Other Funds Used During Construction
421	Gain on Disposition of Property
421	Other Miscellaneous Non-operating Income
	Total Other Income

OTHER INCOME DEDUCTIONS

421	Loss on Disposition of Property
425	Miscellaneous Amortization
426	Miscellaneous
	Total Other Income Deductions

TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS

408	Taxes Other Than Income Taxes
409	Federal Income Tax

409	State Income Tax
	Total Taxes Applicable to Other Income and Deductions
	Income Before Interest Charges

INTEREST CHARGES

427	Interest on Long-Term Debt
428	Amortization of Debt Discount and Expense
429	Amortization of Premium on Debt
431	Other Interest Expense
432	Allowance for Borrowed Funds Used During Construction—Credit
	Net Interest Charges
	Income Before Extraordinary Items
	Extraordinary Items After Taxes
	Net Income "

RESPONSE:

See Exhibit RAD-18 Attachment A which provides the requested comparative operating statements. Set forth below are explanations of the causes of major variances.

OPERATING REVENUES

Residential Sales (Variation ($8,122))

The variance is due primarily to decreases of $16.2 million in the Hourly Pricing Service revenue and $1.5 million in the NUG Rider Energy charge offset by increases of $7.2 million in the Universal Service Charge and $1.6 million in the Smart Meter Technology revenues.

Commercial Sales (Variation ($10,927))

The variance is due primarily to decreases of $11.7 million in the Hourly Pricing Service revenue and $0.9 million in the NUG Rider Energy charge offset by increases of $1.0 million in the Smart Meter Technology revenues.

Sales for Resale (Variation ($8,398))

The variance is due primarily to an $8.0 million decrease to PJM Spot market energy revenues.

OPERATING EXPENSES

Operation and Maintenance expense Account 401-2 (Variance ($43,104))

The variance is primarily due to decreases of $44.5 million in purchased power, and $3.5 million in customer assistance expenses. These decreases were partially offset by increases of $4.1 million in distribution expenses, and $3.3 million in administrative & general expenses.

Account 403 Depreciation expense (Variance $2,829)

The variance is due primarily to a $2.8 million increase in depreciation on assets offset by $0.1 million decrease in depreciation cost of removal.

Account 404-5 Amortization and depletion of utility plant (Variance $2,029)

The variance is due primarily to a $2.0 million increase in amortization and depletion on assets.

Account 407.3 Regulatory debits (Variance ($1,490))

This variance is due primarily to a $3.8 million decrease in the NUG deferral offset partly by a $1.3 increase in the DSSR deferral and a $1.0 increase in the 2006 PJM Transmission deferral.

Account 407.4 Regulatory credits (Variance $26,856)

This variance is due primarily to increases of $13.8 million in the Price to Compare deferral, $10.6 million in the Universal Service deferral, $1.7 million in the Energy Efficiency deferral, and $1.5 million in the Smart Meter deferral.

Account 408.1 Taxes other than income taxes (Variance ($1,086)

This variance is due primarily to a decrease of $1.2 million in the PA gross receipts tax.

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METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-2:

"Provide a summary of test year adjustments which sets forth the effect of the adjustment upon the following: operating revenues, operating expenses, taxes other than income taxes, operating income before income taxes, State income tax, Federal income tax and income available for return. In addition, test year adjustments shall be presented on the basis of the major account categories set out at II-D-1."

RESPONSE:

See Met-Ed Exhibit RAD-19 Attachment A.

Metropolitan Edison Company

Line No.	Adj. No.	Support Schedule No.	Description	Operating Revenues (1)	Operating Expenses (2)	Taxes Other Than Income Taxes (3)	Operating Income Before Income Taxes (4)	State Income Tax (5)	Federal Income Tax (6)	Income Available for Return (7)=(4)-(5)-(6)
1			As budgeted (Exhibit RAD-2, Page 1, col. 1)	$ 741,619	$ 545,899	$ 42,733	$ 152,987	$ -	$ 45,356	$ 107,631
			Normalizations and Adjustments							
			Operating Revenues							
2	1		Base Operating Revenues	25			25	2	8	15
3	2		State Tax Surcharge Revenues	-			-	-	-	-
4			Other Operating Revenues				-	-	-	-
5	3		Eliminate non-jurisdictional transmission revenues	(55,404)			(55,404)	(5,535)	(17,454)	(32,415)
										-
			Operating Expenses							-
			Distribution							
6	4	1	Distribution payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	263			(263)	(26)	(83)	(154)
7	4	1	Service company distribution payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	66			(66)	(7)	(21)	(39)
8	4		Eliminate non-jurisdictional transmission expense	(9,140)			9,140	913	2,879	5,347
9	4		Amortization of gain or loss on reacquired debt	81			(81)	(8)	(26)	(47)
			Customer Accounts							
10	5		Customer account payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	92			(92)	(9)	(29)	(54)
11	5		Service company customer account payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	99			(99)	(10)	(31)	(58)
12	5	1	Increased O&M costs associated with increased number of customers in normalized revenue levels	10			(10)	(1)	(3)	(6)
13	5	2	Interest on customer deposits	1,256			(1,256)	(125)	(396)	(735)
			Customer Service							
14	6		Customer service payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	44			(44)	(4)	(14)	(26)
			Administrative & General Expenses							
15	7		A&G payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	76			(76)	(8)	(24)	(44)
16	7		Service company A&G payroll adjustment to reflect year end employee levels and ongoing wage and salary rates	148			(148)	(15)	(47)	(87)
17	7	1	Adjust OPEB expense to service cost level	2,814			(2,814)	(281)	(887)	(1,646)
18	7	2	Adjust Pension Expense to ten year cash level	14,046			(14,046)	(1,403)	(4,425)	(8,218)
19	7	3	Adjust employee benefit costs	305			(305)	(30)	(96)	(178)
20	7		Adjustment to remove non-jurisdictional A&G expense	(2,660)			2,660	266	838	1,556
21	7		Rate Case expenses normalized over 2 years	(502)			502	50	158	294
22	7		Increase in O&M costs for accelerated (3 day) switching for customers moving to a new supplier	311			(311)	(31)	(98)	(182)
23	7		Less legacy meters from budget	(330)			330	33	104	193
			Depreciation Expense							
24	8		Adjustment for average remaining life accrual for jurisdictional plant	(7,041)			7,041	703	2,218	4,119
25	8		Adjustment of cost of removal/salvage expenses to a jurisdictional five year average	8,020			(8,020)	(801)	(2,527)	(4,692)
26	8	1	Adjustment for amortization of legacy meters	10,759			(10,759)	(1,075)	(3,389)	(6,295)
			Amortization							
27	9		Adjustment for storms	21,655			(21,655)	(2,163)	(6,822)	(12,670)
28	9		Remove rate case expenses from budget	750			(750)	(75)	(236)	(439)
29	9		Remove legacy meters from budget	330			(330)	(33)	(104)	(193)
30	9		Remove accretion expense	(49)			49	5	15	29
			Taxes Other than Income							
31	10		Eliminate non-jurisdictional payroll taxes			(490)	490	49	154	287
32	10		Eliminate other non-jurisdictional taxes			(503)	503	50	158	294
33	10		Adjustment for gross receipts tax at normalized revenue level			13	(13)	(1)	(4)	(8)
34	10	1	Adjustment for payroll taxes on normalized payroll			40	(40)	(4)	(13)	(23)

Line No.	Adj. No.	Support Schedule No.	Description	Operating Revenues (1)	Operating Expenses (2)	Taxes Other Than Income Taxes (3)	Operating Income Before Income Taxes (4)	State Income Tax (5)	Federal Income Tax (6)	Income Available for Return (7)=(4)-(5)-(6)
			Federal & State Income Taxes							
			Income Taxes							
35	11		Current federal & state income taxes				-	15,679	10,020	(25,698)
36	12		Deferred federal & state income taxes				-		(2,699)	2,699
37	13		Amortization of ITC	-	-	-	-	-	81	(81)
38			Total adjustments (Exhibit RAD-2, Page 1, col. 2)	$ (55,379)	$ 41,403	$ (940)	$ (95,842)	$ 6,104	$ (22,792)	$ (79,154)
39			Budget as Adjusted (Exhibit RAD-2, Page 1, col. 3)	$ 686,240	$ 587,302	$ 41,793	$ 57,145	$ 6,104	$ 22,564	$ 28,477
40			Adjustments to achieve required return - Total PaPUC Jurisdictional	152,643	-	9,006	143,637	14,349	45,251	84,038

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-3:

"List and explain all nonrecurring or extraordinary expenses incurred in the test year and all expenses included in the test year which do not occur yearly but are of a nature that they do occur over an extended period of years, for example, nonyearly maintenance programs, and the like."

RESPONSE:

The test year ending 4/30/16 does not include any non-recurring or extraordinary expenses.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-4:

"As a separate item, list extraordinary property losses related to property previously included in cost of service when the gain or loss on this property has occurred or is likely to occur in the future test year. The proposed ratemaking treatment of extraordinary gains and losses must also be disclosed. Sufficient supporting data must be provided."

RESPONSE:

There are no extraordinary property losses.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-5:

"Provide the amount of accumulated reserve for uncollectible accounts, method and rate of accrual, amounts accrued and amounts written off in each of the last 3 calendar years."

RESPONSE:

The future estimate of uncollectible accounts is based on a historically determined average of net write-offs to sales for each utility company. For the Uncollectible Customer Reserve, the regulated utility companies at FirstEnergy determine a 3-year rolling average of net write-offs to sales (36 months of net write-offs/ 36 months of sales). This percentage is then multiplied by the latest 6 months of sales to arrive at a reserve.

Beginning in 2013, the Uncollectible Customer Reserve includes a reserve for the Purchase of Receivables program (POR). This is determined by using a percentage of Non- POR Uncollectible Customer Reserve to Non- POR Customer Receivable Arrears (Uncollectible Customer Receivable Reserve/Non-Current Customer Receivable Arrears). This percentage is then multiplied by the POR Non-Current Customer Receivable Arrears to arrive at a reserve.

The Utility may record additional uncollectible customer reserve amounts as deemed necessary to fairly value Accounts Receivable.

The accruals, net write-offs and balance in FERC Account No. 144.1 Accumulated Reserve for Uncollectible Accounts for the last three calendar years are as follows:

Line No.	Description	Amount
1	**Balance, January 1, 2011**	$ (3,867,730)
2	Accruals	$ (11,522,378)
3	Write-offs (Net)	$ 12,374,770
4	**Balance, December 31, 2011**	$ (3,015,338)
5	Accruals	$ (12,841,208)
6	Write-offs (Net)	$ 12,833,226
7	**Balance, December 31, 2012**	$ (3,023,320)
8	Accruals	$ (14,333,240)
9	Write-offs (Net)	$ 10,315,484
10	**Balance, December 31, 2013**	$ (7,041,076)

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-6:

"Supply detailed calculations to support the total claim for rate case expense, including supporting data for outside service rendered. Provide the items comprising the estimated rate case expense claim for the current rate case."

RESPONSE:

The claim in the current rate case proceeding for rate case expenses, shown on Met-Ed Exhibit RAD-2 page 18, is based on the following total estimated expenses proposed to be amortized for ratemaking purposes over two years:

	Amount ($000)
Legal Expenses	$ 275
Expert Witnesses	33
Other	187
Total	$ 495

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-7:

"Submit schedules for the test year and for the 12-month period immediately prior to the test year showing by major components, if included in claimed test year expenses, the expenses incurred in each of the following expense categories:

(a) Miscellaneous general expenses, including account 930.
(b) Outside service expenses.
(c) Regulatory commission expenses.
(d) Advertising expenses, including advertising engaged in by trade associations whenever the utility has claimed a contribution to the trade association as a ratemaking claim - provide explanation of types and purposes of such advertising.
(e) Research and development expenses – provide a listing of major projects.
(f) Charitable and civic contributions, by recipient and amount.

Explain major variances between the test year expenses and those expenses for the prior 12-month period."

RESPONSE:

(a) – (d) See Page 2 of 3
(e) – (f) See Page 3 of 3

Line No.	Description	12 Months Ending April 30 2016	March 31 2015	March 31 2014
			(in thousands)	
	Acct 913 - Advertising & 930 - Miscellaneous General Expense			
	Institutional or Goodwill Advertising Expenses (913 & 930.1)			
1	Goodwill Advertising	$ 35	$ 34	$ 24
2	Print Advertising	-	-	65
3	Radio Advertising	-	-	8
2	Total Institutional or Goodwill Advertising	$ 35	$ 34	$ 97
	Misc. General Expenses (930.2)			
3	Bank Fees	$ 209	$ 209	$ 174
4	Misc Regulatory Expenses	192	242	236
5	Corporate Dues - Trade	133	133	116
6	Financing Admin Fees	123	123	195
7	Corporate Dues - Civic	39	39	27
8	Association Fees and Dues	3	3	4
9	Licenses, Permits & Regulation	-	-	7
10	FENOC - Benefits	-	-	6
11	FENOC - Tax	-	-	3
12	Other Miscellaneous Expenses	-	-	11
13	Total Miscellaneous General Expenses	$ 698	$ 748	$ 778
14	Accounts 913 & 930	$ 733	$ 782	$ 876
	Account 923 - Outside Services Employed			
1	Outside Contractors	$ 19,232	$ 22,987	$ 17,732 (A)
2	FE Service Co. Assessments	16,146	15,840	14,831
3	FENOC	7	7	42
4	West Penn	2	2	1
5	Penelec	1	1	1
6	Total Account 923	$ 35,388	$ 38,837	$ 32,607
	Account 928 - Regulatiory Commission Expenses			
1	Regulatory Commission Expense	$ 2,632	$ 2,469	$ 2,460
2	Total Account 928	$ 2,632	$ 2,469	$ 2,460

(A) The variance in Outside Contractors expense is due primarily to fluctuations in Smart Meter and Energy Efficiency programs.

Line No.	Description of Project	12 Months Ending April 30 2016	12 Months Ending March 31 2015	12 Months Ending March 31 2014	
		(in thousands)			
1	***Research and Development Expenditures***	$ 145	$ 141	$ 218	(B)

(B) For the year ended March 31, 2014, R&D expenses represents actual amounts included in the income statement. Future amounts are projected expenditures which will settle to either capital or expense depending on the nature of the project.

Acct. 426.1 -- Donations

Organizations				
1	Property Donations	$ 117	$ 117	$ 108
2	Civic Donations	19	19	29
4	Total charitable and civic contributions	$ 136	$ 136	$ 137

Metropolitan Edison Company
Charges by Affiliates
(000's)

Line No.	Description	Twelve Months Ending April 30, 2016 Labor *	Other than Labor **	Total	Twelve Months Ending March 31, 2015 Labor *	Other than Labor **	Total	Twelve Months Ending March 31, 2014 Labor *	Other than Labor **	Total
1	Production	$ -	$ -	$ -	$ -	$ -	$ -	$ 161	213	$ 374
2	Transmission	967	1,186	2,153	933	1,153	2,086	971	628	1,600
3	Distribution	2,623	1,395	4,018	2,479	1,372	3,852	3,517	2,293	5,810
4	Customer Accounting and Information	3,941	3,405	7,346	3,917	3,419	7,336	4,963	3,592	3,480
5	Administrative and General	5,904	11,531	17,435	6,509	10,179	16,689	6,054	6,533	17,661
6	Total	$13,435	$ 17,516	$ 30,951	$13,839	$ 16,124	$ 29,963	$ 15,666	$ 13,260	$ 28,925

* Labor is direct payroll only; excludes payroll overhead
** OTL includes payroll overhead

SERVICE AGREEMENT

This Service Agreement ("Agreement") is entered into as of the 25th day of February, 2011, by and between each of the associate companies listed on the signature page hereto (each a "Client Company"), and FirstEnergy Service Company, an Ohio corporation ("Service Company").

WHEREAS, Service Company is a direct wholly-owned subsidiary of FirstEnergy Corp., a holding company under the Public Utility Holding Company Act of 2005, as amended (the "Act");

WHEREAS, Service Company has been formed for the purpose of providing administrative, management and other services to FirstEnergy Corp. and its associate companies, including Client Company (together, the "Client Companies"); and

WHEREAS, Client Company believes that it is in its interest to enter into an arrangement whereby Client Company may agree to purchase such administrative, management and other services from Service Company as Client Company may choose at cost as determined in accordance with this Agreement and the Act;

NOW, THEREFORE, in consideration of the mutual covenants contained herein and other valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, intending to be legally bound, hereby agree as follows:

1. DESCRIPTION OF SERVICES.

Service Company agrees to provide certain administrative, management or other services (the "Services") to Client Company similar to those supplied to other Client Companies of Service Company. Such services are and will be provided to Client Company only at the request of Client Company. Exhibit A hereto lists and describes all of the Services that are available from Service Company.

2. PERSONNEL.

In order to provide the Services, Service Company will employ executive officers, accountants, financial advisers, technical advisers, attorneys and other persons with the necessary qualifications. If necessary, Service Company may also arrange for the services of nonaffiliated experts, consultants and attorneys in connection with the performance of any of the Services provided under this Agreement.

3. COMPENSATION AND ALLOCATION.

As and to the extent required by law, Service Company provides and will provide such services at fully allocated cost, determined in accordance with the Act. Exhibit A hereof contains rules for determining and allocating such costs.

4. TERMINATION AND MODIFICATION.

Either party to this Agreement may terminate this Agreement by providing 60 days written notice of such termination to the other party. This Agreement is subject to termination or modification at any time to the extent its performance may conflict with the provisions of the Act or with any rule, regulation or order of the Federal Regulatory Energy Commission (the "Commission") adopted before or after the making of this Agreement. This Agreement shall be subject to the approval of any state commission or other state regulatory body whose approval is, by the laws of said state, a legal prerequisite to the execution and delivery or the performance of this Agreement.

5. SERVICE REQUESTS.

Client Company and Service Company will prepare a Service Request on or before September 30th of each year listing Services to be provided to Client Company by Service Company and any special arrangements related to the provision of such Services for the coming year, based on Services provided during the preceding year. Client Company and Service Company may supplement the Service Request during the year to reflect any additional or special Services that Client Company wishes to obtain from Service Company, and the arrangements relating thereto.

6. BILLING AND PAYMENT.

Unless otherwise set forth in a Service Request, payment for Services provided by Service Company shall be by making remittance of the amount billed or by making appropriate accounting entries on the books of Client Company and Service Company. Billing will be made on a monthly basis, with the bill to be rendered as soon as practicable after the close of the month, and remittance or accounting entries completed within 30 days of billing. Any amount remaining unpaid after 30 days following receipt of the bill shall bear interest thereon from the due date of the bill until payment at a rate equal to the prime rate on the due date.

7. NOTICE.

Where written notice is required by this Agreement, all notices, consents, certificates, or other communications hereunder shall be in writing and shall be deemed given when mailed by United States registered or certified mail, postage prepaid, return receipt requested, addressed as follows:

To Client Company: c/o President
76 South Main St.
Akron, Ohio 44308

To Service Company: c/o Vice President and Controller
76 South Main Street
Akron, Ohio 44308

8. GOVERNING LAW.

This Agreement shall be governed by and construed in accordance with the laws of the State of Ohio, without regard to its conflict of laws provisions.

9. MODIFICATION.

No amendment, change or modification to this Agreement shall be valid, unless made in writing and signed by both parties hereto.

10. ENTIRE AGREEMENT.

This Agreement, together with its exhibits, constitutes the entire understanding and agreement of the parties with respect to its subject matter, and effective upon the execution of this Agreement by the respective parties hereof, any and all prior agreements, understandings or representations with respect to this subject matter are hereby terminated and canceled in their entirety and are of no further force and effect, except to the extent transactions thereunder have taken place prior to such effective date in which case such agreements will govern the terms of such transactions.

11. WAIVER.

No waiver by either party hereto of a breach of any provision of this Agreement shall constitute a waiver of any preceding or succeeding breach of the same or any other provision hereof.

12. ASSIGNMENT.

This Agreement shall inure to the benefit and shall be binding upon the parties and their respective successors and assigns. No assignment of this Agreement or either party's rights, interests or obligations hereunder may be made without the other party's consent, which shall not be unreasonably withheld, delayed or conditioned.

13. SEVERABILITY.

If any provision or provisions of this Agreement shall be held by a court of competent jurisdiction to be invalid, illegal, or unenforceable, the validity, legality, and enforceability of the remaining provisions shall in no way be affected or impaired thereby.

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed effective as of the 25th day of February, 2011. This Agreement supercedes any previous agreement between the Service Company and the Client Companies.

FirstEnergy Service Company

By: _____
Harvey L. Wagner
Vice President & Controller

Client Companies:

Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company
Pennsylvania Power Company
American Transmission Systems, Incorporated
Pennsylvania Electric Company
Waverly Electric Power & Light Company
Metropolitan Edison Company
Monongahela Power Company
The Potomac-Edison Company
West Penn Power Company
PATH - Allegheny Land Acquisition Company
PATH Allegheny Maryland Transmission Company, LLC
PATH Allegheny Transmission Company, LLC
PATH Allegheny Virginia Transmission Corporation
AYE Series, Potomac-Appalachian Transmission Highline, LLC
Trans-Allegheny Interstate Line Company

By: _____
Charles E. Jones
President

Jersey Central Power & Light Company

By: _____

Donald M. Lynch
President

EXHIBIT A
DESCRIPTION OF SERVICES AND ALLOCATION METHODOLOGY

1. Description Of Services

Overview

This Exhibit provides a description of all services provided by Service Company departments and the cost allocation methodologies to be used in connection therewith. All products and services are subject to Service Level Standards as negotiated between the Service Company department and Client Company. Each Client Company is classified as either a "Utility Subsidiary" or a "Non-Utility Subsidiary".

2. Cost Allocation Methodology

Overview

The costs of services provided by Service Company will be directly assigned, distributed or allocated by activity, project, program, work order or other appropriate basis. The primary basis for charges to affiliates is the direct charge method. The methodologies listed below pertain to all other costs which are not directly assigned but which make up the fully allocated cost of providing the product or service. The costs of product and services provided by the ServeCo that cannot be charged directly to the Subsidiary receiving the product or service will be allocated among the associate companies by utilizing one of the methods described below that most accurately distributes the costs. The method of cost allocation varies based on the department rendering the service. The allocation methods used by Service Company are as follows:

a. **"Multiple Factor – All"** - For the Indirect Costs for products or services benefiting the entire FirstEnergy system, FirstEnergy and all Subsidiaries will bear a fair and equitable portion of such costs. FirstEnergy will bear 5% of these Indirect Costs. The remaining Indirect Costs will be allocated among the Utility Subsidiaries and the Non-Utility Subsidiaries benefiting from the services provided based on FirstEnergy's equity investment in the respective groups. A subsequent allocation step will then occur. Among the Utility Subsidiaries, allocations will be based upon the **"Multiple Factor - Utility"** method. Among the Non-Utility Subsidiaries, allocations will be based upon the **"Multiple Factor - Non-Utility"** method.

b. **"Multiple Factor – Utility"** - For the Indirect Costs for a product or service solely benefiting one or more of the Utility Subsidiaries, each such Utility Subsidiary so benefiting will be charged a portion of the Indirect Costs based on the sum of the weighted averages of the following factors:

1. Gross transmission and/or distribution plant
2. Operating and maintenance expense excluding purchase power and fuel costs

3. Transmission and/or distribution revenues, excluding transactions with affiliates

These three (3) factors have been determined to be the most appropriate for the Utility Subsidiaries in the FirstEnergy system. Each factor will be weighted equally so that no one facet of the electric utility operations inordinately influences the distribution of Indirect Costs.

c. **"Multiple Factor - Non-Utility"** - For the Indirect Costs for products or services solely benefiting the Non-Utility Subsidiaries, each Non-Utility Subsidiary so benefiting receiving the product or service will be charged a proportion of the Indirect Costs based upon the total assets of each Non-Utility Subsidiary, including the generating assets under operating leases from the Utility Subsidiaries.

d. **"Multiple Factor - Utility and Non-Utility"** - For the Indirect Costs for a product or service benefiting one or more of the Utility and Non-Utility Subsidiaries, each such Subsidiary so benefiting is first assigned a distribution ratio that is in proportion to the Indirect Costs based on FirstEnergy's equity investment in such Subsidiaries. Following this distribution, a subsequent allocation step will then occur. Among the Utility Subsidiaries, allocations will be based upon the **"Multiple Factor-Utility."** Among the Non-Utility Subsidiaries, allocations will be based upon **"Multiple Factor - Non-Utility"**

e. **"Direct Charge Ratio"** - The ratio of direct charges for a particular product or service to an individual Subsidiary as a percentage of the total direct charges for a particular product or service to all Subsidiaries benefiting from such services. Indirect Costs are then allocated to each Subsidiary based on the calculated ratios.

f. **"Number of Customers Ratio"** - For costs of products and services driven by the number of Utility customers, the allocation method that will be used will be the number of Utility customers for the respective Utility Subsidiary receiving the product or service divided by the total number of utility customers.

g. **"Number of Shopping Customers Ratio"** - A "shopping customer" is defined as a Utility customer who has selected a competitive electric generation supplier. For costs of products and services driven by the number of shopping customers, the allocation method that will be used will be the number of shopping customers for the respective Utility Subsidiary receiving the product or service divided by the total number of shopping customers.

h. "Number of Participating Employees – General" - For costs of products and services driven by all participating employees within the FirstEnergy system, the allocation method that will be used will be the number of participating employees for the respective Subsidiary receiving the product or service divided by the total number of participating employees.

i. "Number of Participating Employees - Utility and Non-Utility" - For costs of products and services driven by participating employees who work for the Utility and Non-Utility Subsidiaries, the Subsidiaries receiving the product or service are first assigned a distribution ratio that is in proportion to the Indirect Costs based on FirstEnergy's equity investment in the respective groups. Costs are further allocated by using the number of participating employees for the respective Subsidiary divided by the total number of participating FirstEnergy employees.

j. "Gigabytes Used Ratio" - Number of gigabytes utilized by a Subsidiary receiving the product or service divided by the total number of gigabytes used by the FirstEnergy system companies applicable to that respective product or service.

k. "Number of Computer Workstations Ratio" - Number of computer workstations utilized by a Subsidiary receiving the product or service divided by the total number of computer workstations in use by the FirstEnergy system companies applicable to that respective product or service.

l. "Number of Billing Inserts Ratio" - Number of billing inserts performed for a Subsidiary receiving the product or service divided by the total number of billing inserts performed for the FirstEnergy system companies applicable to that respective product or service.

m. "Number of Invoices Ratio" - Number of invoices processed for a Subsidiary receiving the product or service divided by the total number of invoices processed for the FirstEnergy system companies applicable to that respective product or service.

n. "Number of Payments Ratio" - Number of monthly payments processed for a Subsidiary divided by the total monthly number of payments processed for the FirstEnergy system companies applicable to that respective product or service. This will not be utilized until some historical information is available out of our new automated system.

o. "Daily Print Volume" - Average daily print volume performed for a Subsidiary receiving the service divided by the total average daily print volume performed for the entire FirstEnergy system.

p. "Number of Intel Servers" - Number of Intel servers utilized by a Subsidiary receiving the product or service divided by the total number of Intel servers utilized by the FirstEnergy system.

q. "Application Development Ratio" - Number of application development hours budgeted for a Subsidiary receiving the service divided by the total number of budgeted application development hours for the year.

r. "Server Support Composite" - The average ratio of unix gigabytes, SAP gigabytes and Intel number of servers for a Subsidiary receiving the service.

3. Descriptions of Products and Services

CALL CENTER

Product or Service	Product / Service Description	Indirect Allocation Methods
Field All Inbound Regulated Calls	Field calls related to billing, credit, new service, service order completion, outages, and other miscellaneous activities.	Multiple Factor – Utility and Non-Utility
Field All Inbound Unregulated Calls	Field calls related to billing, credit, new service, service order completion, outages, and other miscellaneous activities.	Multiple Factor – Utility and Non-Utility

CUSTOMER SERVICE

Product or Service	Product / Service Description	Indirect Allocation Methods
Supplier Services	Provide customer services support to electric generation suppliers, administer and maintain Electronic Data Interface (EDI) functions and invoice suppliers.	Number of Shopping Customers Ratio
Regulatory Interface and Process Improvement: Supplier	Liaison to ensure Customer Choice requirements and develop and execute plans to improve supplier services processes.	Number of Shopping Customers Ratio
Market Support Generation (MSG) Administration	Administer and support MSG supplier functions.	Number of Shopping Customers Ratio
Regulatory Interface and Process Improvement: Regulatory	Respond to regulatory complaints from customers and develop and execute plans to improve regulatory compliance processes.	Number of Customers Ratio
Compliance	Work with regions to communicate and ensure regulatory requirements.	Multiple Factor – Utility
Power Billing	Provide billing functions for large commercial/industrial contract customers.	Number of Customers Ratio
Revenue Reporting	Perform and manage revenue reporting functions.	Number of Customers Ratio
Billing Exception Processing	Process billing exceptions.	Number of Customers Ratio
Remittance Processing	Process customer payments and deposit funds.	Number of Payments Ratio
Human Services	Coordinate and administer the various social services programs.	Number of Customers Ratio

Arrears Management/ Outsourcing Services Incorporated (OSI) Administration	Coordinate and perform arrears, credit and bankruptcy functions. Manage outside collections agencies' performance and OSI credit activities.	Number of Customers Ratio
Revenue Protection Administration	Perform revenue reporting and compliance functions.	Number of Customers Ratio
Metrics and Budget/ Customer Satisfaction Measurement	Manage Customer Services and Call Center Departments' budgets and measure performance and customer satisfaction results.	Number of Customers Ratio
Policy/Procedures Development and Documentation	Develop, document and communicate Customer Services policies and procedures.	Number of Customers Ratio
Bill Administration/ Forms Administration	Design standardized customer bills, envelopes, and forms.	Number of Customers Ratio
Meter Reading Support	Coordinate Meter Reading schedules and routing activities.	Number of Customers Ratio
Customer Information System (CIS) Control	Operate and maintain CIS.	Number of Customers Ratio

ECONOMIC DEVELOPMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Economic Development Services	Foster economic development to encourage capital investment in FirstEnergy's service areas.	Multiple Factor – Utility

TRANSMISSION & DISTRIBUTION TECHNICAL SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Forestry	Provide forestry services.	Multiple Factor – Utility
Distribution Reliability and Asset Records	Services include Joint User contracts, public works coordination, reliability reporting to regions and Public Utility Commissions, mutual assistance coordination, PowerOn support, cable locate ticket screening and tariff support.	Multiple Factor – Utility

Design Standards	Services include line material and construction standards, distribution line and underground maintenance practices and support, new business process support, and service practices.	Multiple Factor – Utility
Substation Services Support	Services include Substation maintenance plan coordination, practices and support, mobile substation administration and planning, and environmental compliance support.	Multiple Factor – Utility
Equipment Repair/Testing Services	Services include the maintenance, installation, maintenance, testing and repair of utility equipment.	Multiple Factor – Utility
Fleet Services	Develop fleet strategy, and perform fleet maintenance practices and support.	Multiple Factor – Utility
Financial Services	Identify revenue enhancements and cost reductions.	Multiple Factor – Utility
Substation Design and Transmission-Line Maintenance Support	Perform substation and transmission line design and project management and transmission line and substation design and material standards, right-of-way and survey services, transmission line maintenance plan coordination, practices and support, FAA activity coordination.	Multiple Factor – Utility
Planning and Protection	Perform planning and protection support for subtransmission system and overall radial system capacity planning overview, and interconnection coordination for distributed technology applications on distribution system.	Multiple Factor – Utility
Capital Budget and Equipment Support	Capital budget development and support, and major equipment specifications and procurement/repair activities for major equipment.	Multiple Factor – Utility

WORKFORCE DEVELOPMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Transmission and Distribution Skills Training	Develop and facilitate technical and safety training for workers associated with distribution activities, including line, substation, meter, fleet, warehouse, field engineering, and dispatch. Provide support through equipment evaluation, training analyses, job assessments, and project coordination.	Number of Participating Employees – General
Customer Service Skills Training	Develop and facilitate skills training for customer service groups.	Multiple Factor – Utility
External Learning Opportunities Through the Power Systems Institute	Develop educational partnerships with colleges to offer two-year degrees in electric utility technology.	Multiple Factor – Utility

ADMINISTRATIVE SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Administrative Support Services	Provides services in production printing, document imaging, graphic services, food services, corporate mailroom and corporate courier.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*
Provide Records Management Services	Provides services in records storage, records retrieval, records retention, records planning and engineering records.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*
Provide Business Services	Provides services in convenience copiers, fax machines, pagers, printers, and business information center.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*

* For services rendered only to the utilities.

EXECUTIVE

Product or Service	Product / Service Description	Indirect Allocation Methods
Executive Management	Consultation and services in management and administration of all aspects of the business.	Multiple Factor – All

COMMUNICATIONS

Product or Service	Product / Service Description	Indirect Allocation Methods
Public Relations	Provides services in media relations, financial communications, annual reports, executive presentation, public relations counsel, corporate writing, internet support and special projects.	Multiple Factor – All
Employee Communications	Provides services with update, retirees, satellite broadcast, human resource-related communications and special projects.	Number of Participating Employees – Utility and Non-Utility
Production	Provides services related to display, photography, Corporate ID, video and employee merchandise.	Multiple Factor – All
Sponsorship	Provides services related to sports marketing, university support and special projects.	Multiple Factor – All
Non-Utility Advertising	Provides services related to broadcast/print, collateral, direct mail, internet/intranet, display/merchandise, yellow/white pages, production/agency support and special projects.	Multiple Factor – Non-Utility
Utility Advertising	Provides services related to TV, radio, print, outdoors, Internet/Intranet, special projects, production, agency support and creative media placement.	Multiple Factor – Utility
Utility Bill Inserts	Provides services developing regulated bill service to Ohio, Pennsylvania and New Jersey.	Multiple Factor – Utility
Utility : Yellow / White Pages	Provides services with regulated yellow/white pages.	Multiple Factor – Utility
Utility: Research	Provides research services.	Multiple Factor – Utility
Ohio Consumer Education	Provides services related to Ohio Consumer Education statewide and locally.	Multiple Factor – Utility
Ohio Deregulation Education	Provides service related to Deregulation Education.	Multiple Factor – Utility

CORPORATE AFFAIRS AND COMMUNITY INVOLVEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Corporate Affairs Activities	Provide administrative support through oversight of the business practices and planning and implementation of staff, senior management and related meetings. Serves as community liaison.	Multiple Factor – Utility
Direct Community Involvement Initiatives	Provides direction in employee volunteerism, supports viable community partnerships and educational initiatives.	Multiple Factor – Utility
Energy Efficiency Programs	Directing and coordinating Ohio Weatherization and Energy Efficiency Programs for Low Income Customers.	Multiple Factor – Utility
Community Initiatives Consulting Services	Consults to regional operations and other business units and client managers for the various community programs.	Multiple Factor – Utility
Contributions Management	Directs, coordinates, monitors, and manages contributions.	Multiple Factor – Utility

CORPORATE

Product or Service	Product / Service Description	Indirect Allocation Methods
Investor Services	Stock administration, perform recordkeeping, transfer agent, registrar, paying agent, reinvestment plan administration and other services for shareholders.	None (All Direct Charge to Holding Co.)
Board of Directors Support	Support and administration of Board of Directors meetings and director compensation.	None (All Direct Charge to Holding Co.)
Annual Meeting Coordination	Coordinate the Annual Meeting of Shareholders, including the preparation and mailing of proxy materials and annual reports and the tabulation of proxies.	None (All Direct Charge to Holding Co.).
Indenture Compliance	Administer the company's indentures	Multiple Factor – Utility

HUMAN RESOURCES

Product or Service	Product / Service Description	Indirect Allocation Methods
Manage Employee Executive Compensation and Benefits	Provide management and supervision for employee and executive compensation and benefits.	Number of Participating Employees – General
Manage Workers Compensation and Disability Management	Provide management and supervision for workers compensation and disability programs.	Number of Participating Employees – General
Provide and Coordinate Human Resources Training	Design, prepare and conduct training.	Number of Participating Employees – General
Provide Employment Services	Provide staffing, relocation and employment expertise.	Number of Participating Employees – General
Provide HRIS Services.	Provide and maintain Human Resources information.	Number of Participating Employees – General
Provide Diversity Management Services	Manage Affirmative Action programs, provide EEO/AA consulting services, and respond to charges.	Number of Participating Employees – General
Manage/ Administer Medical Services and Wellness Programs	Establish compliance, develop, implement, and administer medical and wellness programs.	Number of Participating Employees – General

INDUSTRIAL RELATIONS

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Labor Contract Negotiations	Provide contract negotiation services for all labor agreements.	Number of Participating Employees – General
Provide Labor Consulting Services	Provide labor consulting services.	Number of Participating Employees – General
Manage/Administer Safety Programs	Develop, implement and administer occupational safety programs.	Number of Participating Employees – General

REAL ESTATE

Product or Service	Product / Service Description	Indirect Allocation Methods
Facilities Management	Management and maintenance of office facilities.	Multiple Factor – All or Multiple Factor Utility*
Facilities Planning and Project Management	Manage office design services, furniture, project management and other capital improvements.	Multiple Factor – All or Multiple Factor Utility*
Management of Real Estate Assets	Support internal and external inquiries regarding the acquisition, divestiture and management of real estate assets	Multiple Factor – All or Multiple Factor Utility*
Manage/Administer Security Programs	Administer physical security, special investigations, security audits, security consultation and contract guard services.	Multiple Factor – All or Multiple Factor Utility*

* For services rendered only to the utilities.

FIRSTENERGY TECHNOLOGIES

Product or Service	Product / Service Description	Indirect Allocation Methods
Strategic Technologies	Develop, support and implement EPRI programs, industry initiatives, research and development programs, collaboratives and activities with universities, labs and the Department of Energy.	Multiple Factor – Utility
New Technology Assessment	Perform assessment activities for strategic technology pilots, technology assessments, marketing tests, customer pilots and due diligence reviews.	Multiple Factor – Utility and Non-Utility
Technical Application and Product Innovation	Develop, analyze and support strategic alliances, joint ventures, strategic startups, direct investments and Portfolio initiatives.	Multiple Factor – Utility and Non-Utility
New Technology and Product Market Deployment	Develop, support and implement the following initiatives: tailored solutions with existing products, commercial packages, operational efficiencies and business area solutions.	Multiple Factor – Utility and Non-Utility
Demand Response Initiatives	Provide support for corporate demand response initiatives.	Multiple Factor – Utility and Non-Utility
Renewable Energy Program and Strategy	Provide support for various corporate and regulatory initiatives to develop and implement renewable energy programs and products.	Multiple Factor – Utility

Regulated Programs and Services	Develop, support and implement programs and strategies to meet corporate initiatives and regulatory mandates and commitments related to Comprehensive Resource Assessment(CRA), customer end-use. technology, distributed generation and load management.	Multiple Factor – Utility
Project Implementation Management Services	Develop and implement end-use and distributed generation technology-based products and services.	Multiple Factor – Utility and Non-Utility

TECHNOLOGY & SUPPORT SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Network Services	Provide Internal Network Services.	Multiple Factor – Utility and Non-Utility
Maintain wireless cell sites and fiber optics network	Maintain internal wireless cell sites and fiber optic network; provide engineering, procurement, and installation services.	Multiple Factor – Utility and Non-Utility

INFORMATION TECHNOLOGY

Product or Service	Product / Service Description	Indirect Allocation Methods
Application Development	Create new or enhance existing applications; including analysis design coding, testing, system integration, and implementation, as well as any required technical writing or project manual development.	Directly Billed
Development Supervision and Tool Support	Supervision of application development employees and the support of development software tools.	Application Development Ratio
Server Support (Unix, SAP)	Create and support the network and server infrastructure to accommodate unix and SAP client server applications.	Gigabytes Used Ratio
Client Server Storage Support	Support of storage requirements for all server applications.	Server Support Composite Ratio
Server Support (Intel)	Create and support the network and server infrastructure to accommodate windows and NT client server applications.	Number of Intel Servers Ratio
Mainframe Processing and Storage Support	Execute mainframe applications, including an appropriate portion of support, started tasks, mainframe backups and microfiche services.	Gigabytes Used Ratio

Desktop Support	Help desk email and end-user tools, remote access, repair services, and general workstation support.	Number of Computer Workstations Ratio
Network Services	Includes voice, data, EMS and radio access.	Direct Charge Ratio
Inserting Services	Provide document bursting, inserting and mailing.	Number of Billing Inserts Ratio
Printing Services	Provide mainframe and client server printing services at the data center.	Daily Print Volume Ratio
Technical Consulting	Provide consulting support to departments and end-users to enable them to leverage their IT capabilities. Provide advice and consultation regarding desktop setups and configurations.	Directly Billed
Training	Provide IT training.	Multiple Factor – Utility and Non-Utility
Business Application Support	Support business application related software licenses and / or hardware maintenance provided by an outside vendor.	Directly Billed
Data Security	Disaster recovery and data security services.	Multiple Factor – Utility and Non-Utility
Project Management Office	Oversee technology projects through benefit.	Multiple Factor – Utility and Non-Utility
Provide Telecommunication Services	Provide telecommunication services and equipment.	Direct Charge Ratio
Portal Support	Support the infrastructure to accommodate internet and infranet application access.	Multiple Factor – Utility and Non-Utility

PERFORMANCE PLANNING

Product or Service	Product / Service Description	Indirect Allocation Methods
Performance Planning Services	Develop, support and execute performance planning services.	Multiple Factor – All

SUPPLY CHAIN

Product or Service	Product / Service Description	Indirect Allocation Methods
Strategic Planning, Demand management and Procurement Projects	Provide assistance in materials and services planning (demand management) and performs special procurement projects.	Multiple Factor – Utility and Non-Utility
Goods and services procurement	Procure material, equipment and contractor services. Establish, manage and administer programs, which allow internal customers to obtain goods without having to process the need through Procurement. Develop specifications, construction standards, schedules, and bills of materials.	Multiple Factor – Utility and Non-Utility
Materials Management Support	Maintain the computerized purchasing and materials management systems, and material related modules; maintain and/or modify select management reports. Analyze Supply Chain processes and measure performance. Monitor and forecast demand to ensure a continuous supply of materials.	Multiple Factor – Utility and Non-Utility
Investment Recovery Projects	Develop and implement plans for disposition of surplus assets.	Multiple Factor – Utility and Non-Utility
Process, Refurbish and Sell Materials	Perform recovery processing, investment recovery processing, refurbishing and selling materials.	Multiple Factor – Utility and Non-Utility
Provide Warehousing Services - Non-nuclear	Receive and place material into stock, insure quality requirements are met at receipt, maintain inventory counts, and update information systems. Fill customer requests for material from stock.	Multiple Factor – Utility and Non-Utility
Provide Warehousing Services - Nuclear	Receive and place material into stock, insure quality requirements are met at receipt, maintain inventory counts, and update information systems. Fill customer requests for material from stock.	None (All direct charged)
Warehousing Space Charge	Provide warehousing space to internal customers.	Multiple Factor – Utility and Non-Utility

CONTROLLERS

Product or Service	Product / Service Description	Indirect Allocation Methods
Accounting Research	Provide accounting research and consulting to ensure compliance with existing and proposed financial reporting, and regulatory accounting requirements.	Multiple Factor - All
Accounts Payable	Nonpayroll corporate disbursement services including account distribution to the general ledger. Resolve problems associated with invoice processing and maintain the accounts payable system.	Multiple Factor - All
Billing Services	Prepare non-retail electric billings.	Multiple Factor Utility
Infrastructure and Corporate Reporting, Accounting and Budgeting	Prepare Corporate Sustaining reports, subsidiary accounting and corporate budgeting, which includes reporting and support of the ledger, property records and SAP system.	Multiple Factor - All
Due Diligence	Assist value centers to determine whether proposed business acquisitions/combinations and similar transactions are desirable from a financial perspective; extensive review/analysis following preliminary review and firm intent to proceed with transaction through commitment and closing phases.	None (All direct charged)
Value Center Accounting and Budgeting	Maintain the property accounting system and provide value center accounting such as management reporting.	Multiple Factor – Utility and Non-Utility
Property Record Maintenance	Maintain corporate continuing property records.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*
Tax Consulting and Research	Conduct tax research and tax consulting to assure compliance with statues, while evaluating alternative tax strategies within the constraints of regulations that provide additional shareholder value to the company. In addition, provide tax-consulting advice to the value centers on tax compliance and reporting issues, which includes business "start-up" support to organizations requiring assistance.	Multiple Factor – All

* For services rendered only to the utilities.

Tax Compliance	Prepare and process all schedules and information associated with corporate and subsidiary tax returns, audits, and tax litigation, assuring compliance with tax regulations and statues.	Multiple Factor – All or Multiple Factor Utility*

* For services rendered only to the utilities.

CREDIT MANAGEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Credit Analysis and Supporting Functions	Provide detailed written credit analysis issuing recommendations on counterparty creditworthiness and assigning credit limits.	Multiple Factor – Utility and Non-Utility
Credit Policies and Procedures	Develop and support credit policies and procedures for managing credit risk. Implement and support standardized credit approval processes.	Multiple Factor – Utility and Non-Utility
Credit Management Information System	Develop and support credit management reports and calculate credit exposure on a corporate wide basis.	Multiple Factor - All

ENTERPRISE RISK MANAGEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
General Risk Management	Develop and maintain an enterprise risk management system.	Multiple Factor - All

INSURANCE SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Insurance Policies	Manage and support insurance policies for all the business units .	Multiple Factor – Utility and Non-Utility
Loss Control Services	Manage and support property inspections to prevent losses.	Multiple Factor – Utility and Non-Utility
Surety Bonds	Manage and support Surety Bonds.	Multiple Factor – Utility and Non-Utility
Risk Transfer and Risk Mitigation Services	Manage and support risk transfer and risk mitigation services.	Multiple Factor – Utility and Non-Utility
Ancillary Coverages	Manage and support ancillary coverages.	None (All direct charged)

INTERNAL AUDIT

Product or Service	Product / Service Description	Indirect Allocation Methods
Audit Services	Perform the following internal audit services based on risk levels and / or requests: financial, performance analysis, safeguarding of assets, computer- related and fraud investigations.	Multiple Factor – All or Multiple Factor – Utility*

INVESTMENT MANAGEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Qualified and Non-qualified Pension and Savings Plan	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Number of Participating Employees – Utility and Non–Utility
FirstEnergy Foundation	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Multiple Factor - All
Voluntary Employee Benefit Association (VEBA) Trust	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Number of Participating Employees – Utility and Non–Utility
Nuclear Decommissioning	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	None (All direct charged)
Non-Utility Generator Trust	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Multiple Factor – Non-Utility
Spent Nuclear Fuel	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	None (All direct charged)
Low-Income Housing Tax Credit Partnership	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Multiple Factor - All

INVESTOR RELATIONS

Product or Service	Product / Service Description	Indirect Allocation Methods
Investor Information	Compile and communicate information to investors.	Multiple Factor – Utility* or Direct Charge to Holding Co.
Investor Education	Target and educate potential investors to promote FirstEnergy's valuation characteristics and business strategy.	None (All Direct Charge to Holding Co.)

* For services rendered only to the utilities.

Regulations Compliance	Ensure compliance with SEC Fair Disclosure regulations.	Multiple Factor - All

FirstEnergy Management Education	Provide education to management of business concerns and valuation issues of analyst/investors	Multiple Factor – All
FirstEnergy Employee Education	Actively promote understanding of financial and investor relations' issues.	Multiple Factor – All

RATES AND REGULATORY AFFAIRS

Product or Service	Product / Service Description	Indirect Allocation Methods
Regulatory Activities and Consulting	Manage regulatory activities and interfaces, including tariff development and interpretation. Monitor and participate in regulatory affairs at the local, state and federal levels.	Multiple Factor – Utility
Customer Pricing and Contracting	Develop pricing programs for regulated electric service for retail and wholesale customers, including "unbundled" costs and prices for generation, transmission and distribution service and support justification to regulators. Provide support in developing pricing for special-purpose customer programs and non-regulated energy services (e.g. prepayment, economic development, interruptible load, conjunctive-billing electric service programs).	Multiple Factor – Utility
Billing Support	Provide assistance calculating customer (external and internal) invoices and operate and maintain systems to render, collect and account for these invoices.	Multiple Factor – Utility
Sales and Load Forecasting	Develop short-term and long-term sales forecast, peak load projections and customer counts	Multiple Factor – Utility and Non-Utility

TREASURY

Product or Service	Product / Service Description	Indirect Allocation Methods
Capital Structure Management and Administration	Perform all activities related to acquiring capital and establish and administer funding, legal documentation, and record-keeping activities associated with finance programs	Multiple Factor – All
Corporate Funds Management	Plan, manage, and operate the corporate "cash-flow-cycle."	Multiple Factor – All
Corporate Forecasting	Provide regulatory support, strategy support, financial modeling and forecasting, financial and economic analysis and development of annual corporate KPI target.	Multiple Factor – All

Capital Project Evaluation and Support	Provide analytical support in the areas of financing, profitability, capital structure and cash flow.	Multiple Factor – Utility and Non-Utility
Investor Relations Activities	Provide institutional and retail security holder, buy and sell-side analysts, rating agencies, and other key members of the financial community with qualitative and quantitative information.	Multiple Factor – All

BUSINESS DEVELOPMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Mergers and Acquisitions Support	Support, evaluate and assist in the management of merger, asset acquisition and asset disposition activities.	None (All direct charged)
Internal Consulting	Perform strategic analysis/business fit, and economic analysis. Provide integration and transitional management services as needed.	None (All direct charged)

GOVERNMENTAL AFFAIRS

Product or Service	Product / Service Description	Indirect Allocation Methods
Federal Governmental Affairs Support	Activities associated with developing and maintaining relationships with federal government institutions; includes lobbying, and other support activities.	None (All direct charged)
State Governmental Affairs Support	Activities associated with developing and maintaining relationships with state government institutions; includes lobbying, and other support activities.	None (All direct charged)

LEGAL

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Governmental Affairs Support	Activities associated with developing and maintaining relationships with government institutions; includes lobbying, litigation, and other support activities.	None (All direct charged)
Nuclear Legal Consultation and Case Management	Provide legal advice for federal and state nuclear matters.	None (All direct charged)
Human Resources Legal Consultation & Case Management	Provide legal advice for human resource matters (including workers compensation, union negotiations, arbitrations, class action lawsuits, etc.).	Multiple Factor – Utility and Non-Utility

Product or Service	Product / Service Description	Indirect Allocation Methods
Employee Benefits Legal Consultation & Case Management	Provide legal advice for employee benefits matters (including health and welfare benefits, tax-qualified and non-tax qualified benefit plans and programs, pension administration, etc.).	Number of Participating Employees – Utility and Non-Utility
Tax Legal Consultation & Case Management	Provide legal advice for tax matters including federal, state & local tax matters (land tax, sales & use tax, IRS, etc.).	Multiple Factor – All
Bankruptcy Legal Consultation & Case Management	Provide legal advice for bankruptcy matters.	Multiple Factor – Utility and Non-Utility
International Legal Consultation & Case Management	Provide legal advice for international matters– contract negotiations, sale/lease agreements.	None (All direct charged)
Non-Utility Legal Consultation & Case Management	Provide legal advice on federal and state matters to Non-Utility Subsidiaries.	Multiple Factor – Non-Utilities
Regulatory Legal Consultation & Case Management	Provide legal advice for federal and state regulatory matters.	Multiple Factor – Utility
Environmental Legal Consultation & Case Management	Provide legal advice for environmental matters (other than PCB – related matters) - federal (EPA) and state (EPA), regulatory/legislative compliance issues.	None (All direct charged)
PCB Environmental Legal Consultation & Case Management	Provide legal advice for PCB-related matters - federal (EPA) and state (EPA), regulatory/legislative compliance issues.	Multiple Factor – Utility
Real Estate Legal Consultation & Case Management	Provide legal advice for real estate matters.	Multiple Factor – Utility and Non-Utility
Corporate Legal Consultation & Case Management	Provide legal advice for general corporate and transactional matters (including SEC filings, Board of Directors matters, PUHCA, Financings, Securities Matters, Intellectual Property, Technology, General Counsel matters, etc.).	Multiple Factor – All
Claims Legal Consultation & Case Management	Provide legal advice for Claims matters.	Multiple Factor – All

CLAIMS

Product or Service	Product / Service Description	Indirect Allocation Methods

Process Receivable Claims	Provide management, supervision, and performance of tasks associated with the resolution and chargeback of receivable claims.	Multiple Factor - All
Provide Corporate Support	Claims support in evaluating claims, and procuring appropriate external/internal legal resources.	Multiple Factor - All

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-8:

"Provide an analysis by function of charges by affiliates, for the test year and the 12-month period immediately prior to the test year, for services rendered included in the operating expenses of the filing company. Explain the nature of the service and the basis on which charges or allocations are made, including a copy of an applicable contract. Also, explain major variances between the charges for the test year and the corresponding charges for the prior 12-month period."

RESPONSE:

See Met-Ed Exhibit RAD-25 Attachment A for a summary of charges budgeted to be billed to Met-Ed by First Energy Service Company for the twelve months ending April 30, 2016 and the 12 months ending March 31, 2015. Met-Ed Exhibit RAD-25 Attachment A also shows the charges billed to Met-Ed by First Energy Service Company for the twelve months ended March 31, 2014.

Also included is a copy of the Service Agreement between the operating subsidiary Metropolitan Edison Company and FirstEnergy Service Company (FE Service) outlining the services to be provided by FE Service and the basis on which charges are to be billed. See Met-Ed Exhibit RAD-25 Attachment B.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-9:

"Prepare a detailed schedule for the test year showing types of social and service organization memberships paid for, the cost thereof, the accounting treatment and whether included in claimed test year expenses."

RESPONSE:

Metropolitan Edison Company
Social and Service Organization Memberships Paid
(000's)

Line No.	Organization	12 Months Ending April 30, 2016 (1)	March 31, 2015 (2)	March 31, 2014 (3)
	Business Associations			
	Account 930			
1	Edison Electric Institute	$ 132	$ 132	$ 116
2	Chamber of Commerce, Economic Development, & Local Community Organizations	40	40	27
3	Southeastern Electric Exchange Inc.			4
4	Other Business / Trade Organizations	3	3	
5	Total Account 930.20	$ 175	$ 175	$ 147
	Account 923			
6	Southeastern Electric Exchange Inc.	-	-	4
		$ -	$ -	$ 4
	Account 426			
7	Edison Electric Institute	31	31	33
		$ 31	$ 31	$ 33
8	Total (line 5 + line 6 + line 7)	$ 206	$ 206	$ 184

Metropolitan Edison Company (Met-Ed)

Payroll and Employee Benefits
($000)

Line No.	Description	12 Months Ending 4/30/2016 Full-Time Bargaining	12 Months Ending 4/30/2016 Full-Time NonBargaining	12 Months Ending 4/30/2016 Total	12 Months Ending 3/31/2015 Full-Time Bargaining	12 Months Ending 3/31/2015 Full-Time NonBargaining	12 Months Ending 3/31/2015 Total	12 Months Ending 3/31/2014 Full-Time Bargaining	12 Months Ending 3/31/2014 Full-Time NonBargaining	12 Months Ending 3/31/2014 Total
	Number of Employees									
1	Average	467	164	631	469	165	634	491	162	653
2	Year-End	467	164	631	467	164	631	485	152	637
3	Straight Time Payroll	$ 36,777	$ 15,679	$ 52,455	$ 35,333	$ 15,043	$ 50,377	$ 33,939	$ 14,583	$ 48,522
4	Overtime Payroll	5,432	774	6,206	5,987	780	6,767	10,068	1,691	11,759
5	Incentive Compensation	1,629	887	2,516	1,706	912	2,618	2,654	2,003	4,657
6	Total Payroll	$ 43,838	$ 17,339	$ 61,177	$ 43,026	$ 16,735	$ 59,762	$ 46,660	$ 18,277	$ 64,937
	Total Company Employee Benefits:									
7	Workers Compensation	$ 317	$ 111	$ 428	$ 317	$ 111	$ 428	$ 310	$ 109	$ 419
8	Pension Costs	(3,303)	(1,160)	(4,463)	(3,833)	(1,348)	(5,181)	(9,172)	(3,221)	(12,392)
9	OPEB	(3,661)	(1,286)	(4,946)	(8,713)	(3,064)	(11,777)	(16,340)	(5,738)	(22,078)
10	Life Insurance	68	24	91	73	26	99	31	11	42
11	Medical/Dental Insurance	4,285	1,505	5,790	4,015	1,412	5,427	4,525	1,589	6,114
12	Executive Benefits	0	660	660	0	636	636	0	(406)	(406)
13	Restricted Stock	0	121	121	0	117	117	0	136	136
14	Savings Plan	2,090	734	2,824	1,657	583	2,240	979	344	1,323
15	Long Term Disability	119	42	161	119	42	161	43	15	57
16	Education Assistance	45	16	60	49	17	67	16	6	21
17	Employee Awards	5	2	7	5	2	7	0	0	0
18	Employee Assistance Program	9	3	12	9	3	12	9	3	12
19	Wellness Program	170	60	230	156	55	211	71	25	96
20	Relocation	0	322	322	0	351	351	0	790	790
21	Other	14	5	19	16	6	22	43	15	58
22	Total Employee Benefits	$ 158	$ 1,159	$ 1,317	$ (6,129)	$ (1,052)	$ (7,181)	$ (19,485)	$ (6,323)	$ (25,808)

(1) Employee Counts exclude Part-time and Temporary employees
(2) Benefit costs allocated to Bargaining/NonBargaining based on average number of employees
except for Executive Benefits, Restricted Stock and Relocation expenses (100% non-bargaining)

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-11:

"Describe costs relative to leasing equipment, including computer rentals, and office space, including terms and conditions of the leases. State method for calculating monthly or annual payments."

RESPONSE:

Line No.	Name of Lessor	Basic Detail of Lease	12 Months Ended April 30, 2016 *(In thousands)*
1	GE Capital Commercial Inc. (successor-in-interest to BLC Corporation)	Motor Vehicles & Trailers – Base term 36-120 months with fixed rate & maximum expected residual of 25% and unguaranteed residual of 13%. At end of base term, option for renewal exists for up to 24 months at 474 BPS plus federal 2 year swap rate. At end of renewal term, option to continue to rent for monthly fee equivalent of 1/12 of 1% of acquisition cost until unit is sold or returned to Lessor. Other Equipment – Base term of 36-120 months with a fixed rate & maximum expected residual of 20% with unguaranteed residual of 13%. At end of base term, option for renewal exists for up to 24 months at 474 BPS plus federal 2 year swap rate. At end of renewal term, option to continue to rent for monthly fee equivalent of 1/12 of 1% of acquisition cost until unit is sold or returned to Lessor.	$955

2	RBS Asset Finance, Inc.	Motor Vehicles & Trailers – Base term 60 months for light and medium duty vehicles, 96 months for heavy duty high use trouble trucks and 120 months for all other heavy duty vehicles & trailers with a $1 buy out at end of term for all. Other Equipment – Base term 96 months for miscellaneous equipment like ATVs, sweeper/scrubbers, etc. and 120 months for construction equipment & forklifts with a $1 buy out at end of term for all. Rates for both motor vehicles/trailers & other equipment leases are fixed based on 200 BPS plus Bloomberg Avg Life swap rate (2.5 years for 60 month term, 4 years for 96 month term and 5.5 years for 120 month term).	$3,642

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-12:

"Submit a statement of past and anticipated changes, since the previous rate case, in major accounting procedures, explain any differences between the basis or procedure used in allocations of revenues, expenses, depreciation and taxes in the current rate case and that used in the prior rate cases, and list all internal and independent audit reports for the most recent 2 year period."

RESPONSE:

A list of all internal audit reports performed by the Internal Audit Department from April 2012 through March 2014 appears on pages 3 through 6.

A list of all independent audits performed from April 2012 thru March 2014 appears on page 6.

The following is a list of major changes in accounting procedures adopted since the previous rate case:

1. In 2006, the Company adopted SFAS 158 (ASC 715), *Accounting for Defined Benefits.* This statement requires employers to recognize an asset or liability for the overfunded or underfunded status of their pension and other postretirement benefit plans (OPEB). For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. The Statement required employers to recognize all unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive income (AOCI), net of tax. Such amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost or income pursuant to the current recognition and amortization provisions.

2. In 2007, the Company adopted FIN 48, *Accounting for Uncertainly in Income Taxes,* which provides guidance for accounting for uncertainty in income taxes in a company's financial statements in accordance with SFAS 109 (ASC 740), *Accounting for Income Taxes.* This interpretation prescribes a financial statement recognition threshold and measurement attribute for tax positions taken or

expected to be taken on a company's tax return. FIN 48 also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation is a two-step process. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination, based on the merits of the position, and should therefore be recognized. The second step is to measure a tax position that meets the more likely than not recognition threshold to determine the amount of income tax benefit to recognize in the financial statements.

FIN 48 also requires companies to recognize interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized in accordance with FIN 48 and the amount previously taken or expected to be taken on the tax return. The Company includes net interest and penalties in the provision for income taxes, consistent with its policy prior to implementing FIN 48.

3. In 2011, the Company changed its method of recognizing actuarial gains and losses for its defined benefit pension and OPEB plans. Previously, the Company recognized the net actuarial gains and losses as a component of AOCI and amortized the gains and losses into income over future periods.

   The Company, with this accounting change, elected to immediately recognize the change in fair value of plan assets and actuarial gains and losses annually in the fourth quarter of each year. The Company retroactively applied immediate recognition of gains and losses for its defined benefit pension and OPEB plans to each year, from 1986 through 2010.

Internal Audits Performed During – April through December 31, 2012

Compliance:

1. Audit of the IBM Consulting Services' Pennsylvania "Smart Meter Implementation and Procurement" Plan Development as of February 10, 2012
2. Limited Scope Review of US Bank Travel Card as of July 27, 2012
3. Audit of Substation Safety/Security Inspection and Corrective Maintenance as of October 3, 2012
4. Review of Purchasing Card Usage – Severed Employees as of December 12, 2012
5. Audit of Met-Ed Energy Delivery Inspection & Maintenance Programs as of November 26, 2012
6. 2012 Corporate Compliance Program Update
7. Annual Review of the Code of Business Conduct as of November 26, 2012

Operational:

1. Audit of the Streetlight Repair Process as of May 2, 2012
2. Data Analysis of Wood Pole Inspection Results (Years 2007-2011) as of October 8, 2012
3. Audit of Rate Change and Rate Adjustment Processes Documentation as of September 17, 2012
4. Energy Efficiency Program Support (Memorandum)

IT Related:

1. Audit of IT Merger Project - Consolidate IT Security Policies (L01) as of March 16, 2012
2. Audit of IT Merger Project - Energy Delivery Meter and Transformer Testing Systems (B07.1) as of February 27, 2012
3. Audit of IT Merge Project - Energy Delivery Graphical Information System (B02.3) as of March 23, 2012
4. Audit of IT Merger Project - Energy Delivery Outage Management Ancillary (B01.2) as of April 13, 2012
5. Audit of IT Merger Project - Energy Delivery Internet Vegetation Management System (B06.1) as of May 7, 2012
6. Audit of IT Merger Project - Cascade (B02.1) as of May 11, 2012
7. Audit of IT Merger Project - Energy Delivery Meter Reading and Route Completion (B07.2) as of May 18, 2012
8. Audit of IT Merger Project - Energy Efficiency & Conservation/Demand Response Program Integration (C03.1) as of May 11, 2012
9. Audit of IT Merger Project - Energy Delivery Outage Management (B01.1) as of May 11, 2012
10. Audit of IT Merger Project - Consolidate Sensitive Customer Information Programs (L01) as of May 21, 2012
11. Audit of IT Merger Project - SAP Project Light-year as of May14, 2012
12. Audit of IT Merger Project - Contact Center Technologies as of June 25, 2012
13. Audit of IT Merger Project - Energy Delivery Work Management System (B04.2) as of June 12, 2012
14. Audit of IT Merger Project - Rates/Load Forecasting System (B08.1) as of April 2, 2012

15. Audit of IT Merger Project - Consolidate eDiscovery and Record Retention Processes (L01.1) as of October 31, 2012

Financial:

1. Audit of the Pennsylvania Energy Efficiency Conservation Service Provider Invoice Validation Guidelines as of January 31, 2012
2. Audit of Hurricane Irene Actual Charges as of May 11, 2012
3. Audit of the October 2011 Snowstorm Actual Charges as of May 11, 2012
4. Reconciliation of Advanced Billing Platform System Data to Electric Distribution Company Data as of July 8, 2012
5. Audit of Regulated Metered But Unbilled Revenue as of September 27, 2012
6. Sarbanes-Oxley Annual Progress Report as of December 28, 2012
7. First Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of March 31, 2012
8. Second Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of June 30, 2012
9. Third Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of September 30, 2012
10. Sarbanes-Oxley Annual Progress Report as of December 28, 2012

Internal Audits Performed During – January through December 31. 2013

Compliance:

1. Audit of 2012 Occupational Safety & Health Administration (OSHA) Recordable Incident Rate as of January 15, 2013
2. Audit Pennsylvania Distribution Vegetation Maintenance Practices as of January 15, 2013 - Privileged and Confidential - Prepared at the Request of Counsel
3. Audit of FirstEnergy's Compliance With Section 114 of the Fair and Accurate Credit Transactions Act as of March 31, 2013
4. Audit of Contract Compliance of Osmose Utilities Services, Inc., as of September 24, 2013
5. Interim Report of the Pre-Implementation Audit of the State Code of Conduct Project as of December 6, 2013
6. 2013 Corporate Compliance Program Update
7. Annual Review of the Code of Business Conduct as of November 27, 2013

Operational:

1. Audit of Energy Delivery Joint Use Revenue as of October 26, 2012
2. Audit of the Implementation of Energy Delivery's Resources on-Demand Application as of November 4, 2013
3. Request for Guidance on Inflated Labor Rates for Diversified Services - Hurricane Sandy – Memorandum
4. Internal Auditing's Partnering Engagement in Documenting Regulated Settlements' Processes and High Risk Procedures

5. Internal Auditing Risk Assessment - Smart Meter Implementation Procurement (SMIP) Project

IT Related:

1. Interim Memorandum - Facilitation of the Control Design for the Office Productivity Transformation Project
2. Interim Report of the Pre-Implementation Audit of the Financial Transformation Project Budget, Forecast, and Planning System as of August 16, 2013
3. Audit of the Cascade Order Integration Project as of June 25, 2013
4. Office Productivity Transformation Testing and Pilot Project
5. Interim Report of the Pre-Implementation Audit of the Financial Transformation Project -
   New General Ledger Technology as of December 6, 2013
6. Interim Report of the Pre-Implementation Audit of the Financial Transformation Project -Business Objects Planning and Consolidation System as of December 6, 2013
7. PowerPlant Continuous Improvement Project

Financial:

1. Audit of FirstEnergy Utilities' Capital and Operation & Maintenance Expenses as of January 31, 2013
2. Audit of the PA Top 100 Hours Demand Response Program Invoicing Process as of February 13, 2013
3. Audit of Transmission Control Center Affiliate Rent Calculation as of July 12, 2013
4. Audit of the Smart Meter Tracking, Accounting and Cost Allocations Process as of November 7, 2013
5. Audit of the 2012 SOx 404 Assessment of Internal Controls as of December 31, 2012
6. First Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of March 31, 2013
7. Second Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of June 30, 2013
8. Third Quarter Sarbanes-Oxley Assessment of Internal Controls Over Financial Reporting as of September 30, 2013
9. Audit of the Purchasing Card Automated Reconciliation and Travel Expenses Implementation as of February 28, 2013
10. Vendor Payroll Tax Reconciliation Audit Review

Internal Audits Performed During – January through March 31, 2014

Compliance:

1. Audit of FirstEnergy Utilities Waste Management Practices as of November 7, 2013
2. Audit of FirstEnergy's Compliance to the Clean Air Act – Sulfur Hexafluoride Mandatory Emissions Tracking and Reporting as of January 21, 2014

Operational:

1. Audit of 2013 Occupational Safety & Health Administration (OSHA) Recordable Incident Rate as of January 10, 2014

IT Related:

1. IT Merger Support - EMS Auxiliary (F01.3)

Financial:

1. Revenew's Payment Recovery Audit for Accounts Payable – 2012
2. Sarbanes-Oxley Annual Progress Report as of December 31, 2013
3. Audit of Pennsylvania Storm Deferral Accounting as of January 14, 2014
4. Sarbanes-Oxley 404 Assessment of Internal Controls Over Financial Reporting as of December 31, 2013
5. Sarbanes-Oxley Annual Progress Report as of December 31, 2013

Independent Audits Performed for the years ended December 31, 2012 and 2013

PricewaterhouseCoopers LLP – Independent Registered Public Accounting Firm

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-13:

"Regardless of whether a claim for negative or positive net salvage is made, attach an exhibit showing gross salvage, cost of removal, third party reimbursements, if any, and net salvage for the test year and 4 previous years."

RESPONSE:

See Met-Ed Exhibit RAD-30 Attachment A

Metropolitan Edison Company
Third Party Reimbursement, Cost of Removal and Salvage

	Third Party Reimbursements (1)	Cost of Removal (2)	Salvage (3)	Net Salvage (4) = (2) + (3)
4/1/2009 thru 3/31/2010	(2,715,469)	17,818,561	(279,964)	17,538,597
4/1/2010 thru 3/31/2011	(2,572,758)	7,831,448	(730,293)	7,101,155
4/1/2011 thru 3/31/2012	(3,974,692)	17,901,617	(390,755)	17,510,862
4/1/2012 thru 3/31/2013	(5,356,002)	28,776,865	(529,057)	28,247,808
4/1/2013 thru 3/31/2014	(4,309,509)	10,625,421	(403,515)	10,221,906
4/1/2014 thru 3/31/2015	(6,676,242)	4,452,739	-	4,452,739
5/1/2015 thru 4/30/2016	(3,687,498)	4,509,478	-	4,509,478

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-14:

"State the amount of debt interest utilized for test year income tax calculations, including the amount so utilized which has been allocated from the debt interest of an affiliate, and provide details of debt interest and allocation computations."

RESPONSE:

Debt interest utilized in the normalized test year under present rates is $36,822,000 as calculated in Met-Ed Exhibit RAD-2, Adjustment No. 11 page 27.

METROPOLTAN EDISON COMPANY

FILING REQUIREMENT II-D-15:

"Provide a schedule for the test year of Federal and Pennsylvania taxes other than income taxes, per books, pro forma at present rates, and pro forma at proposed rates, including the following tax categories:

(a) Social Security.
(b) Unemployment.
(c) Capital stock.
(d) Public utility
(e) P.U.C. assessment.
(f) Other property taxes.
(g) Any other appropriate tax categories."

RESPONSE:

See Met-Ed Exhibit RAD-32 Attachment A for a schedule of taxes other than income taxes showing per budget and pro forma at present rates for the future test year.

Metropolitan Edison Company
Summary of Taxes other than Income Taxes
Twelve Months Ending April 30, 2016
($000)

Line No.	Description	Per Budget Total Electric Operating (1)	Pro Forma Under Present Rates Normalizing Adjustments (2)	As Adjusted (3)
	Federal			
1	Federal and State payroll taxes	$ 4,694	$ 490	$ 4,204
	State			
2	Capital Stock	149	33	116
3	Gross Receipts	38,732	-	38,732
4	Public utility realty	1,976	441	1,535
5	Gross premiums	-	-	-
6	Use tax	113	-	113
	Local			
7	Real estate & other	131	29	102
8	TOTAL	$ 45,795	$ 993	$ 44,802

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-16:

> "Submit a schedule showing the adjustments from taxable net income per books to taxable net income pro forma under existing rates and pro forma under proposed rates, together with an explanation of all normalizing adjustments. Submit detailed calculations supporting taxable income before State and Federal income taxes where the income tax is subject to allocation due to operations in another state or due to operation of other taxable utility or non-utility business, or by operating divisions or areas."

RESPONSE:

See Met-Ed Exhibit RAD-33 Attachment A.

Line No.	Description	In Thousands Fully Future Test Year Ending 4/30/16 Per Budget (1)	Pro-Forma Test Year Under Existing Rates (2)	Pro-Forma Test Year Under Proposed Rates (3)
1	Balance after preferred stock dividends	$ -		
	Net utility operating income:			
2	Exhibit RAD-2, page 1, line 23, column 13	$59,277	$ 29,730	
3	Exhibit RAD-2, page 3, line 23, column 33			$ 113,767
	Add:			
4	Income Taxes-Federal	29,037	19,923	65,173
5	Income Taxes-State	10,182	6,318	20,667
6	Provision for Deferred Income Taxes	7,347	3,598	3,598
7	Provision for Deferred Income Taxes-Credit	(1,011)	-	-
8	Investment Tax Credit	(364)	(283)	(283)
9	Book Income Subject to Tax	$ 104,468	$ 59,286	$ 202,922
	Adjustments:			
10	Book Depreciation	59,938	63,640	63,640
11	Tax Depreciation	(58,244)	(62,848)	(62,848)
12	Interest expense per Ratemaking	-	36,822	36,822
13	Business Meals	70		70
14	Life Insurance	(82)		(82)
15	NJ Min Tax	(2)		(2)
16	ESOP Dividend	(196)		(196)
17	Lobbying	31		31
18	Capitalized Interest-Avoided Costs in Excess of AFC	-		-
19	FAS 123R - Restricted Stock Units	-		-
20	FAS 143	-		-
21	Price to Compare Rider	7,483		7,483
22	ESOP Compensation Expense	-		-
23	Storm Damage & Other Deferrals	22,738		22,738
24	Deferrals / Amort SEIA			-
25	OPEBs	(2,549)		(2,549)
26	Tax Capitalized Interest	802		802
27	Reacquired Debt - Book Amortization of Loss	1,118		1,118
28	Casualty Loss	(17,909)		(17,909)
29	Section 263	(5,023)		(5,023)
30	T&D Repairs	(20,002)		(20,002)
31	AFUDC Equity	(1,343)		(1,343)
32	Capitalized Interest-Book AFC	(892)		(892)
33	PA PTC Deferral	7,483		7,483
34	Pension Accrual	(3,253)		(3,253)

Line No.	Description	In Thousands Fully Future Test Year Ending 4/30/16 Per Budget (1)	Pro-Forma Test Year Under Existing Rates (2)	Pro-Forma Test Year Under Proposed Rates (3)
35	Research & Development - 174	(415)		(415)
36	Asset Retirement Obligation	49		49
37	Capital Lease Vehicle - Book Expense	745		745
38	Universal Service Program (incl interest)	6,265		6,265
39	Other Reg Assets / Liabilities	(5,979)		(5,979)
40	CIAC - Post 86	-		-
41	State Taxable Income before Tax Preferences	$ 95,301 0	$ 96,900	$ 229,675
42	State Tax Preference Items	-	-	-
43	State Taxable Income	$ 95,301	$ 96,900	$ 229,675
	State Income Tax:			
44	Current Year	10,182	9,680	22,945
45	Total State Tax	$ 10,182	$ 9,680	$ 22,945
46	Less: State Tax Preference Items	-		-
47	Federal Taxable Income (Line 40-L42-L43)	$ 85,119	$ 87,220	$ 206,730

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-17:

"Submit a schedule showing for the last 5 years the income tax refunds, plus interest - net of taxes, received from the Federal government due to prior years' claims."

RESPONSE:

See Met-Ed Exhibit RAD-34 Attachment A.

Metropolitan Edision Company
Income Tax Refunds Prior Year Claims

( ) represents refunds

		Tax Refunds	Interest Rec	0.414935 Tax On Interest	Net Interest
Received 2009					
Claim for Refund					
	2001	(1,043,681.00)	(315,072.98)	130,734.81	(184,338.17)
Received 2010					
Interest Netting Claim					
	2001		(9,124.65)	3,786.14	(5,338.51)
NOL Carryback Claim	2009	(57,805,978.00)			
Received 2011					
Audit Settlement					
	2001	(484,798.00)	(155,231.00)	64,410.77	(90,820.23)
	2003	(3,223,577.00)	(810,659.00)	336,370.79	(474,288.21)
	2004	(1,281,749.00)	(724,754.00)	300,725.80	(424,028.20)
	2007	(1,628,952.00)	(97,283.00)	40,366.12	(56,916.88)
Received 2012					
NOL Carryback Claim	2011	(3,485,470.00)			
Received 2013					
None					
Total		(68,954,205.00)	(2,112,124.63)	876,394.43	(1,235,730.20)

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-18:

"Furnish a breakdown of major items comprising prepaid and deferred income tax charges and other deferred income tax credits, reserves and associated reversals on liberalized depreciation."

RESPONSE:

See Met-Ed Exhibit RAD-35 Attachment A.

Metropolitan Edison Company
Accumulated Deferred Taxes
($000)

Line No.		Balance at 04/30/16 (1)	(2)	Balance at 03/31/15 (3)	(4)	Balance at 03/31/14 (5)	(6)	Balance at 12/31/13 (7)	(8)
	Account 190-Accumulated Deferred Income Taxes								
1	Above Market NUG Liability	10,870		10,870		10,870		10,870	
2	Amortization Premium/Discount on Debt	807		397		79		-	
3	Asset Retirement Obligation - TMI2 Rad	96,011		95,989		95,963		95,957	
4	Asset Retirement Obligation -TMI2 Non Rad	1,257		1,257		1,257		1,257	
5	Bad Debts	2,922		2,922		2,922		2,922	
6	Charitable Contribution Limitation	217		217		217		217	
7	Company Debt - Gain on Reacquisition	405		470		530		547	
8	Consumer Education	320		320		320		320	
9	Customer Advances for Construction Operating	26		26		26		26	
10	Customer Deposits - Electric Service	5		5		5		5	
11	Decom TMI2 Non - Qualified Trust Tax Exempt Interest	53,819		53,819		53,819		53,819	
12	Decommissioning TMI2	36,567		36,567		36,567		36,567	
13	Decommissioning Unrealized Gain/Loss	2,477		2,477		2,477		2,477	
14	Deferred Compensation	383		383		383		383	
15	Default Serv Support-Unbilled Def	(298)		(296)		238		345	
16	DOE Spent Nuclear Fuel Disposal Interest - TMI	13,467		13,467		13,467		13,467	
17	Energy Efficiency Conservation Phase 2	1,706		1,706		1,706		1,706	
18	Energy Efficiency Deferral - EEC-C	4,605		4,108		3,617		3,532	
19	Energy Efficiency Unbilled Deferral	107		107		107		107	
20	Environmental Asset - Ash Sites	23		23		23		23	
21	FAS 112 - Medical Benefit Accrual	449		449		449		449	
22	FAS 123 R - APIC	402		402		402		402	
23	FAS 123R - Performance Shares	8		8		8		8	
24	FAS 123R - Restricted Stock	282		282		282		282	
25	FAS 123R - Restricted Stock Units	733		733		733		733	
26	FAS 123R - Stock Options	19		19		19		19	
27	FAS 133 - Hedging Transactions OCI	-		-		-		21	
28	FAS 158 Pension	282		282		282		296	
29	Federal NOL	7,685		8,538		23,355		23,355	
30	FICA on Vacation Accrual	140		140		140		140	
31	Investment Tax Credit	3,297		3,577		3,835		3,974	
32	Lease Expense Merrill Creek	11,560		11,560		11,560		11,560	
33	Merrill Creek Lease Improvement	6		6		6		6	
34	NUG Unbilled Deferral	203		203		203		203	
35	OCI - EDCP	134		134		134		139	
36	OCI - GPU SERP	1		1		1		1	
37	PA CNI NOL	3,379		5,329		7,331		7,331	
38	Pension EDCP-SERP Payments	41		41		41		41	
39	Pensions & Benefits in Excess of Max	127		127		127		127	
40	Pensions Expense	170,375		171,834		173,394		173,809	
41	Price to Compare Unbilled Deferral	9,286		9,286		9,286		9,286	
42	Reserve for Obsolescence	456		456		456		456	
43	Self Insurance - General Liability	199		199		199		199	
44	Self Insurance Reserve Workmans Compensaton	208		208		208		208	
45	Severance Wages	3		3		3		3	
46	Smart Meter Deferral/AMI	65		65		65		65	
47	Smart Meter Unbilled Deferral	125		125		125		125	
48	Solar Photovoltaic Req-Unbilled Def	52		52		52		52	
49	Solar Photovoltaic Req Charge Rider	847		665		356		288	
50	Storm Adjustment	520		520		520		520	
51	Tax Audit Reserves - General Taxes	938		938		938		938	
52	TMI-2 Monitored Storage- Disallowed Costs	5,507		5,507		5,507		5,507	
53	Universal Service Fund	7,091		4,892		3,682		3,430	
54	USCR Unbilled Deferral	803		803		803		803	
55	Vacation Pay Accrual	1,657		1,657		1,657		1,657	
56	FIN47 ARO Asbestos Remediation	397		397		397		397	
	Total Account 190		452,973		454,272		471,149		471,377
	Account 281-283 Accum. Deferred Income Taxes								
57	Liberalized Depreciation	(590,527)		(569,234)		(556,746)		(552,214)	
58	2013 PTC Admin	(326)		(326)		(326)		(326)	
59	Accounts Receivable - Deferred Revenue	(1,163)		(1,163)		(1,163)		(1,163)	
60	Company Debt - Loss on Reacquisition	(1,094)		(1,205)		(1,431)		(1,646)	
61	Decommissioning TMI2 Qual Principal	(26,803)		(26,803)		(26,803)		(26,803)	
62	Decommissioning TMI2 Qualified Investment	(106,355)		(106,355)		(106,355)		(106,355)	
63	Decommissioning TMI2 Unrealized Gain/Loss	(2,544)		(2,544)		(2,544)		(2,544)	
64	Decommissioning Trust - Pour Over Deduction	(74,752)		(74,752)		(74,752)		(74,752)	
65	Energy Efficiency Phase 2 Unbilled Deferral	(711)		(711)		(711)		(711)	

Metropolitan Edison Company
Accumulated Deferred Taxes
($000)

Line No.		Balance at 04/30/16 (1)	(2)	Balance at 03/31/15 (3)	(4)	Balance at 03/31/14 (5)	(6)	Balance at 12/31/13 (7)	(8)
66	Energy Insurance Services Cell 6	(53)		(53)		(53)		(53)	
67	FAS 109 Gross Up	(55,465)		(55,308)		(55,304)		(55,049)	
68	FAS 115 - Investment in Securities	(34)		(34)		(34)		(34)	
69	FAS 123R - Restricted Stock Deduction	(97)		(97)		(97)		(97)	
70	FAS 123R - Restricted Stock Unit Deduction	(403)		(403)		(403)		(403)	
71	FAS 123R - Stock Options Exercised Deduction	(452)		(452)		(452)		(452)	
72	FAS 158 OPEB	(4,667)		(7,603)		(12,851)		(14,308)	
73	FE Service Non Property Timing Allocation	(5,576)		(5,576)		(6,016)		(6,163)	
74	FE Service RSU 162(m) Val. Allow Allocation	(332)		(332)		(332)		(332)	
75	FE Service Tax Interest Allocation	(5)		(5)		(5)		(5)	
76	Incentive Compensation	(6)		(6)		(6)		(6)	
77	Incremental PJM Deferral & Interest	(21,324)		(21,324)		(21,324)		(21,324)	
78	Interest on Universal Services	648		222		(61)		(117)	
79	NUG Derivative	(11,582)		(11,582)		(11,582)		(11,582)	
80	OPEB Adj - Health Reform Act	(1,916)		(1,916)		(1,916)		(1,916)	
81	Other Post Employ Benefits - Deferred	(2)		(2)		(2)		(2)	
82	Other Post Employment Benefits O&M%	(20,645)		(19,440)		(16,426)		(15,560)	
83	PA Corporate Net Income	(359)		(359)		(359)		(359)	
84	Pensions Contribution	(109,962)		(109,962)		(109,962)		(109,962)	
85	Price to Compare Rider	1,088		(2,259)		(2,643)		(1,550)	
86	Reverse Capital Gain	(12)		(12)		(12)		(12)	
87	Regulatory Assets - Other	(494)		(494)		(494)		-	
88	State Income Tax - Fed Deferred Only	(6,799)		(6,799)		(6,799)		(6,799)	
89	State Income Tax - RAR - Federal	(233)		(233)		(233)		(233)	
90	Storm Damage	1,666		(8,600)		(19,551)		(21,935)	
91	Tax Basis Step-Up	(38)		(32)		(30)		(30)	
92	Vegetation Management - Transmission	(437)		(437)		(437)		(437)	
93	Carrying Charge on Plant Held for Future Use	(344)		(344)		(344)		(344)	
	Total Account 281-283		(1,042,110)		(1,036,535)		(1,038,559)		(1,035,578)
	Total Deferred Taxes		(589,137)		(582,263)		(567,410)		(564,201)

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-19:

> "Explain how the Federal corporate graduated tax rates have been reflected for rate case purposes. If the Pennsylvania jurisdictional utility is part of a multi-corporate system, explain how the tax savings are allocated to each member of the system."

RESPONSE:

Met-Ed is not entitled to a Federal graduated tax rate. Met-Ed files as a member of a Consolidated group and its taxable income exceeds where graduated rates apply. Therefore, the Company uses a flat 35% Federal income tax rate in this filing.

FirstEnergy allocates its current federal consolidated income tax liability, pursuant to an agreement approved by the Securities and Exchange Commission, in accordance with the Energy Policy Act of 2005.

Members of the FirstEnergy consolidated group follow the allocation rules under the IRS Regulations under Code Section 1552. The consolidated group is treated as one taxpayer for federal income tax. Each member is required to compute its separate company taxable income. The members with positive taxable income (Paying Members) pay the consolidate tax liability based on an allocation of its separate company income. The aggregate of all amounts paid by Members of the consolidated, as a result of the excess of each Members' Separate Return Tax liability, (as determined under Section 1.1552-1(a)(2)(ii) of the IRS Regulations) over the amount allocated to such Member as its share of the Consolidated Tax Liability under Code Section 1552 (i.e., the Tax Benefit Amount) is paid by FirstEnergy to the other Members (the "Loss Members") which had tax deductions, losses and credits to which such payments by the Paying Members are attributable. The apportionment of such payments among Loss Members is allocated among the group Members pursuant to IRS Regulations Section 1.1502-21(b).

However, the Tax Benefit Amount allocated to FirstEnergy and paid to FirstEnergy as a result of its being a Loss Member is limited to its Tax Benefit Amount determined by multiplying it total loss benefit amount by a fraction, the numerator of which is FirstEnergy's interest deduction attributable to Acquisition Indebtedness, and the denominator of which is the sum of all of FirstEnergy's deductions. The portion of FirstEnergy's Tax Benefit Amount which cannot be allocated and paid to FirstEnergy due to the operation of this limitation is reallocated to Paying Members of the Consolidated Group other than FirstEnergy in accordance with the method described in Sections 1.1502-33(d)(3) and 1.1552-1(a)(2) of the IRS Regulations.

The general effect of the method is to first allocate the consolidated tax liability among the Members of the Consolidated Group on the basis of the percentage of the total consolidated tax which the tax of such Member, if computed on a separate return basis would bear to the total amount of the taxes for all Members of the group so computed. Then the method allocates an additional amount (the "Tax Benefit Amount") to each Member up to, but not greater than, the excess, if any, of its Separate Return Tax liability, over the amount allocated to such Member in the previous sentence. The total of the Tax Benefit Amounts allocated to Members results in payments to the Members who had items of deduction, loss or credits to which such Tax Benefit Amount is attributable.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-20:

"Explain the treatment given to costs of removal in the income tax calculation and the basis for such treatment."

RESPONSE:

On property acquired from 1971 to 1980, the company utilizes the A.D.R. Tax Depreciation Method.

Under those regulations, when an asset is retired, the cost of dismantling, demolishing, or removing is deductible as a current year's expense.

In June, 1977, Metropolitan Edison Company filed with the Internal Revenue Service an application for a change in accounting for cost of removal on pre-1971 property to conform with treatment for book and regulatory purposes. The Internal Revenue Service's acceptance of this application was dated October 19, 1977.

On property acquired in 1981 and subsequent thereto, the company (in accordance with ACRS and MACRS regulations) elected to use Cost of Removal in the calculation of gain or loss on retirements of 1981 and subsequent property.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-21:

"Show income tax loss/gain carryovers from previous years. Show loss/gain carryovers by years of origin and amounts remaining by years at the beginning of the test year."

RESPONSE:

See Met-Ed Exhibit RAD-38 Attachment A for the Net Operating Loss ("NOL") Carryforward schedule.

Metropolitan Edison Company
Net Operating Loss Carryforwards - Federal & State
Cumulative Balance at 12-31-14

	2011	2012	2013	2014	Total
Federal NOL	$ 42,333,963	$ 23,021,568	$ -	$ -	$ 65,355,531
2014 Utilization	(23,272,040)				(23,272,040)
Balance	$ 19,061,923	$ 23,021,568	$ -	$ -	$ 42,083,491
					-
PA NOL	$ 112,898,985	$ -	$ -	$ -	$ 112,898,985
2012 Utilization	(3,000,000)	-	-	-	(3,000,000)
2013 Utilization	(30,055,692)	-	-	-	(30,055,692)
2014 Utilization	(27,713,701)				(27,713,701)
Balance	$ 52,129,592	$ -	$ -	$ -	$ 52,129,592

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-22:

"State whether the company eliminates tax savings by the payment of actual interest on construction work in progress not in rate base claim. If response is affirmative:

(a) Set forth amount of construction claimed in this tax savings reduction, and explain the basis for this amount
(b) Explain the manner in which the debt portion of this construction is determined for purposes of the deferral calculations.
(c) State the interest rate used to calculate interest on this construction debt portion, and the manner in which it is derived.
(d) Provide details of calculation to determine tax savings reduction, and state whether State taxes are increased to reflect the construction interest elimination."

RESPONSE:

One of the revisions made to the Internal Revenue Code (IRC) by the Tax Reform Act of 1996 was the elimination of the current deduction for construction period interest. The IRC now requires construction period interest to be capitalized for tax purposes using an avoided cost methodology. This methodology results in a similar required capitalized interest amount for tax purposes than the debt component of AFUDC. Therefore, there are no current tax savings to eliminate.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-23:

"Under section 1552 of the Internal Revenue Code (26 U.S.C.A. § 1552) and 26 CFR 1.1552-1 (1983), if applicable, a parent company, in filing a consolidated income tax return for the group, must choose one of four options by which it must allocate total income tax liability of the group to the participating members to determine each member's tax liability to the Federal government (if this interrogatory is not applicable, so state):

(a) State what option has been chosen by the group.
(b) Provide, in summary form, the amount of tax liability that has been allocated to each of the participating members in the consolidated income tax return for the test year and the most recent 3 years for which data is available.
(c) Provide a schedule, in summary form, of contributions, which were determined on the basis of separate tax return calculations, made by each of the participating members to the tax liability indicated in the consolidated group tax return. Provide total amounts of actual payments to the tax depository for the tax year, as computed on the basis of separate returns of members.
(d) Provide the most recent annual income tax return for the group.
(e) Provide details of the amount of the net operating losses of any member allocated to the income tax returns of each of the members of the consolidated group for the test year and the 3 most recent years for which data is available, together with a summary of the actual tax payments for those years.
(f) Provide details of the amount of net negative income taxes, after all tax credits are accounted for, of any member allocated to the income tax return of each of the members of the consolidated group for the test year and the 3 most recent years for which data is available, together with a summary of the actual tax payments for those years."

RESPONSE:

(a) The option used is Reg. §1.1552-1(a)(2) – the tax liability of the group is allocated based on the percentage of total tax computed on a separate basis for each member over the total amount of tax for all members of the group so computed.

(b) See Met-Ed Exhibit RAD-40, Attachment A[1], page 1, for the amount of the tax liability that has been allocated to each of the participating members in the Consolidated Federal income tax return for the most recent three years.

(c) See Met-Ed Exhibit RAD-40, Attachment A, pages 7 – 39, for the payments and refunds made for the most recent filed returns for years 2010, 2011, and 2012 as computed on the basis of separate returns of members.

(d) See Met-Ed Exhibit RAD-40, Attachment A, pages 2 – 6, for a copy of the U.S. Corporation Income Tax Return (Form 1120) as filed by FirstEnergy Corp. and Subsidiaries for the year 2012.

(e) See Met-Ed Exhibit RAD-40, Attachment A, pages 2 - 39.

(f) See Met-Ed Exhibit RAD-40, Attachment A, pages 2 - 39.

[1] Attachment A to Met-Ed Exhibit RAD-40 is **Highly Confidential** and is being provided to the Commission in hard copy only.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-24:

"Provide detailed computations by vintage year showing State and Federal deferred income taxes resulting from the use of accelerated tax depreciation associated with post-1969 public utility property, ADR rates, and accelerated tax depreciation associated with post-1980 public utility property under the Accelerated Cost Recovery System (ACRS).

(a) Reconcile and explain any differences in the base used to calculate State and Federal deferred income taxes.

(b) State whether tax depreciation is based on all rate base items claimed as of the end of the test year, and whether it is the annual tax depreciation at the end of the test year.

(c) Reconcile differences between the deferred tax balance, as shown as a reduction to rate base, and the deferred tax balance as shown on the balance sheet."

RESPONSE:

(a) See Met-Ed Exhibit RAD-41 Attachment A. No basis difference, however, there is a timing difference due to PA disallowance in year one of the 50% Federal Bonus Depreciation.

(b) See Met-Ed Exhibit RAD-41 Attachment A. Tax depreciation for the future test year is based on all electric plant in service claimed as of 4/30/16 and the annual tax depreciation is based on the same plant.

(c) See Met-Ed Exhibit RAD-41 Attachment B.

METROPOLITAN EDISON COMPANY
Summary of Deferred Income Taxes
Based upon Electric Plant in Service April, 2013 - March, 2014

		Deferral of Taxes			Pro Forma Under Present Rates	
Vintage Year		State	Federal	Total	Normalizing Adjustments	Total
Provision:	1970	-	-	-		-
	1971	-	-	-		-
	1972	-	994	994		994
	1973	-	1,216	1,216		1,216
	1974	-	3	3		3
	1975	-	324	324		324
	1976	-	323	323		323
	1977	-	151	151		151
	1978	-	2,989	2,989		2,989
	1979	-	608	608		608
	1980	-	524	524		524
	1981	-	1,653	1,653		1,653
	1982	-	3,387	3,387		3,387
	1983	-	5,118	5,118		5,118
	1984	-	6,706	6,706		6,706
	1985	-	3,113	3,113		3,113
	1986	-	7,071	7,071		7,071
	1987	-	5,857	5,857		5,857
	1988	-	19,107	19,107		19,107
	1989	-	11,953	11,953		11,953
	1990	-	11,401	11,401		11,401
	1991	-	70,803	70,803		70,803
	1992	-	8,259	8,259		8,259
	1993	-	33,436	33,436		33,436
	1994	-	348,509	348,509		348,509
	1995	-	556,863	556,863		556,863
	1996	-	334,362	334,362		334,362
	1997	-	455,081	455,081		455,081
	1998	-	627,400	627,400		627,400
	1999	-	356,328	356,328		356,328
	2000	-	430,603	430,603		430,603
	2001	-	446,242	446,242		446,242
	2001 30%	-	16,759	16,759		16,759
	2002	-	70,482	70,482		70,482
	2002 30%	-	128,483	128,483		128,483
	2003	-	3,305	3,305		3,305
	2003 30%	-	102,719	102,719		102,719
	2003 50%	-	25,796	25,796		25,796
	2004	-	(6,700)	(6,700)		(6,700)
	2004 30%	-	134,720	134,720		134,720
	2004 50%	-	27,184	27,184		27,184
	2005	-	363,392	363,392		363,392
	2006	-	795,398	795,398		795,398
	2007	-	810,669	810,669		810,669
	2008	-	297,955	297,955		297,955
	2008 50%	-	187,419	187,419		187,419
	2009	-	364,375	364,375		364,375
	2009 50%	-	595,660	595,660		595,660
	2010	-	(14,489)	(14,489)		(14,489)
	2010 100%	-	-	-		-
	2010 50%	-	261,521	261,521		261,521
	2011	-	235,878	235,878		235,878
	2011 100%	-	3,305	3,305		3,305
	2011 50%	-	134,883	134,883		134,883
	2012	-	161,593	161,593		161,593
	2012 50%	-	1,569,236	1,569,236		1,569,236
	2013	-	229,209	229,209		229,209
	2013 50%	-	11,587,892	11,587,892		11,587,892
	2014	-	2,141,004	2,141,004		2,141,004
Total Provision		-	23,978,032	23,978,032	-	23,978,032

METROPOLITAN EDISON COMPANY
Summary of Deferred Income Taxes
Based upon Electric Plant in Service April, 2013 - March, 2014

Vintage Year	Deferral of Taxes State	Deferral of Taxes Federal	Total	Pro Forma Under Present Rates: Normalizing Adjustments	Pro Forma Under Present Rates: Total
Reversal					
1970	-	(4,636)	(4,636)		(4,636)
1971	-	(15,968)	(15,968)		(15,968)
1972	-	(13,356)	(13,356)		(13,356)
1973	-	(15,151)	(15,151)		(15,151)
1974	-	(16,365)	(16,365)		(16,365)
1975	-	(7,345)	(7,345)		(7,345)
1976	-	(71,384)	(71,384)		(71,384)
1977	-	(14,748)	(14,748)		(14,748)
1978	-	16,307	16,307		16,307
1979	-	22,161	22,161		22,161
1980	-	44,228	44,228		44,228
1981	-	(94,410)	(94,410)		(94,410)
1982	-	(100,051)	(100,051)		(100,051)
1983	-	(170,282)	(170,282)		(170,282)
1984	-	(162,105)	(162,105)		(162,105)
1985	-	(247,619)	(247,619)		(247,619)
1986	-	(275,896)	(275,896)		(275,896)
1987	-	(275,958)	(275,958)		(275,958)
1988	-	(292,748)	(292,748)		(292,748)
1989	-	(331,844)	(331,844)		(331,844)
1990	-	(347,057)	(347,057)		(347,057)
1991	-	(371,036)	(371,036)		(371,036)
1992	-	(372,071)	(372,071)		(372,071)
1993	-	(277,084)	(277,084)		(277,084)
1994	-	(328,666)	(328,666)		(328,666)
1995	-	(445,490)	(445,490)		(445,490)
1996	-	(282,369)	(282,369)		(282,369)
1997	-	(360,251)	(360,251)		(360,251)
1998	-	(439,378)	(439,378)		(439,378)
1999	-	(270,252)	(270,252)		(270,252)
2000	-	(333,594)	(333,594)		(333,594)
2001	-	(324,223)	(324,223)		(324,223)
2001 30%	-	(447)	(447)		(447)
2002	-	(171,193)	(171,193)		(171,193)
2002 30%	-	42,613	42,613		42,613
2003	-	(169,789)	(169,789)		(169,789)
2003 30%	-	35,419	35,419		35,419
2003 50%	-	10,166	10,166		10,166
2004	-	(271,769)	(271,769)		(271,769)
2004 30%	-	(5,753)	(5,753)		(5,753)
2004 50%	-	103,448	103,448		103,448
2005	-	(60,873)	(60,873)		(60,873)
2006	-	(529,054)	(529,054)		(529,054)
2007	-	(756,360)	(756,360)		(756,360)
2008	-	(346,644)	(346,644)		(346,644)
2008 50%	-	(55,327)	(55,327)		(55,327)
2009	-	(434,693)	(434,693)		(434,693)
2009 50%	-	342,458	342,458		342,458
2010	-	45,779	45,779		45,779
2010 100%	-	(159,460)	(159,460)		(159,460)
2010 50%	-	122,703	122,703		122,703
2011	-	(1,018,618)	(1,018,618)		(1,018,618)
2011 100%	-	(691,714)	(691,714)		(691,714)
2011 50%	-	(11,896)	(11,896)		(11,896)
2012	-	(100,801)	(100,801)		(100,801)
2012 50%	-	(210,754)	(210,754)		(210,754)
2013	-	30,949	30,949		30,949
2013 50%	-	159,393	159,393		159,393
2014	-	(78,714)	(78,714)		(78,714)
Total Reversal	-	(10,359,574)	(10,359,574)	-	(10,359,574)
Net Provision	-	13,618,458	13,618,458	-	13,618,458

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service April, 2013 - March, 2014

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
Provision						
1970	-	0%	35%	-	-	-
1971	-	0%	35%	-	-	-
1972	2,839	0%	35%	-	994	994
1973	3,474	0%	35%	-	1,216	1,216
1974	8	0%	35%	-	3	3
1975	926	0%	35%	-	324	324
1976	923	0%	35%	-	323	323
1977	431	0%	35%	-	151	151
1978	8,541	0%	35%	-	2,989	2,989
1979	1,738	0%	35%	-	608	608
1980	1,496	0%	35%	-	524	524
1981	4,625	0%	35%	-	1,619	1,619
1982	9,678	0%	35%	-	3,387	3,387
1983	14,624	0%	35%	-	5,118	5,118
1984	19,160	0%	35%	-	6,706	6,706
1985	8,894	0%	35%	-	3,113	3,113
1986	20,202	0%	35%	-	7,071	7,071
1987	16,133	0%	35%	-	5,646	5,646
1988	43,848	0%	35%	-	15,347	15,347
1989	33,205	0%	35%	-	11,622	11,622
1990	30,922	0%	35%	-	10,823	10,823
1991	197,360	0%	35%	-	69,076	69,076
1992	21,255	0%	35%	-	7,439	7,439
1993	84,370	0%	35%	-	29,530	29,530
1994	978,940	0%	35%	-	342,629	342,629
1995	1,496,098	0%	35%	-	523,634	523,634
1996	869,054	0%	35%	-	304,169	304,169
1997	1,232,880	0%	35%	-	431,508	431,508
1998	1,606,989	0%	35%	-	562,446	562,446
1999	909,832	0%	35%	-	318,441	318,441
2000	1,155,874	0%	35%	-	404,556	404,556
2001	1,194,770	0%	35%	-	418,169	418,169
2001 30%	45,291	0%	35%	-	15,852	15,852
2002	193,212	0%	35%	-	67,624	67,624
2002 30%	339,677	0%	35%	-	118,887	118,887
2003	7,924	0%	35%	-	2,774	2,774
2003 30%	176,771	0%	35%	-	61,870	61,870
2003 50%	62,376	0%	35%	-	21,832	21,832
2004	(17,422)	0%	35%	-	(6,098)	(6,098)
2004 30%	357,363	0%	35%	-	125,077	125,077
2004 50%	63,635	0%	35%	-	22,272	22,272
2005	907,656	0%	35%	-	317,680	317,680
2006	2,085,732	0%	35%	-	730,006	730,006
2007	2,104,433	0%	35%	-	736,552	736,552
2008	806,863	0%	35%	-	282,402	282,402
2008 50%	455,068	0%	35%	-	159,274	159,274
2009	1,008,045	0%	35%	-	352,816	352,816
2009 50%	1,531,603	0%	35%	-	536,061	536,061
2010	(42,279)	0%	35%	-	(14,798)	(14,798)
2010 100%	-	0%	35%	-	-	-
2010 50%	644,394	0%	35%	-	225,538	225,538
2011	631,979	0%	35%	-	221,193	221,193
2011 100%	9,442	0%	35%	-	3,305	3,305
2011 50%	344,570	0%	35%	-	120,599	120,599
2012	378,734	0%	35%	-	132,557	132,557
2012 50%	3,816,949	0%	35%	-	1,335,932	1,335,932
2013	571,085	0%	35%	-	199,880	199,880
2013 50%	32,882,828	0%	35%	-	11,508,990	11,508,990
2014	6,117,155	0%	35%	-	2,141,004	2,141,004
	65,452,172			**-**	**22,908,260**	**22,908,260**
Provision Gains/Losses Page (6)				**-**	**$1,069,737**	**$1,069,737**
Provision - Non - TMI				**-**	**$23,977,997**	**$23,977,997**

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service April, 2013 - March, 2014

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
Reversal						
1970	(9,688)	0%	48%	-	(4,636)	(4,636)
1971	(33,295)	0%	48%	-	(15,968)	(15,968)
1972	(27,856)	0%	48%	-	(13,356)	(13,356)
1973	(31,606)	0%	48%	-	(15,151)	(15,151)
1974	(34,145)	0%	48%	-	(16,365)	(16,365)
1975	(15,333)	0%	48%	-	(7,345)	(7,345)
1976	(148,772)	0%	48%	-	(71,384)	(71,384)
1977	(30,802)	0%	48%	-	(14,748)	(14,748)
1978	(13,643)	0%	48%	-	(6,501)	(6,501)
1979	(8,624)	0%	46%	-	(3,947)	(3,947)
1980	(21,780)	0%	46%	-	(9,992)	(9,992)
1981	(228,628)	0%	42%	-	(95,638)	(95,638)
1982	(247,484)	0%	41%	-	(100,275)	(100,275)
1983	(429,729)	0%	40%	-	(171,095)	(171,095)
1984	(418,085)	0%	39%	-	(162,492)	(162,492)
1985	(651,290)	0%	38%	-	(248,428)	(248,428)
1986	(752,780)	0%	37%	-	(276,187)	(276,187)
1987	(798,131)	0%	35%	-	(278,125)	(278,125)
1988	(834,692)	0%	35%	-	(292,748)	(292,748)
1989	(955,653)	0%	35%	-	(331,843)	(331,843)
1990	(1,001,168)	0%	35%	-	(347,057)	(347,057)
1991	(1,064,866)	0%	35%	-	(371,036)	(371,036)
1992	(1,062,239)	0%	35%	-	(371,749)	(371,749)
1993	(791,668)	0%	35%	-	(277,084)	(277,084)
1994	(939,046)	0%	35%	-	(328,666)	(328,666)
1995	(1,272,828)	0%	35%	-	(445,490)	(445,490)
1996	(806,769)	0%	35%	-	(282,369)	(282,369)
1997	(1,029,288)	0%	35%	-	(360,251)	(360,251)
1998	(1,255,366)	0%	35%	-	(439,378)	(439,378)
1999	(772,148)	0%	35%	-	(270,252)	(270,252)
2000	(953,126)	0%	35%	-	(333,594)	(333,594)
2001	(926,352)	0%	35%	-	(324,223)	(324,223)
2001 30%	(1,277)	0%	35%	-	(447)	(447)
2002	(489,124)	0%	35%	-	(171,193)	(171,193)
2002 30%	121,750	0%	35%	-	42,613	42,613
2003	(485,111)	0%	35%	-	(169,789)	(169,789)
2003 30%	101,198	0%	35%	-	35,419	35,419
2003 50%	29,047	0%	35%	-	10,166	10,166
2004	(776,482)	0%	35%	-	(271,769)	(271,769)
2004 30%	(16,437)	0%	35%	-	(5,753)	(5,753)
2004 50%	295,566	0%	35%	-	103,448	103,448
2005	(173,923)	0%	35%	-	(60,873)	(60,873)
2006	(1,511,584)	0%	35%	-	(529,054)	(529,054)
2007	(2,161,030)	0%	35%	-	(756,360)	(756,360)
2008	(990,412)	0%	35%	-	(346,644)	(346,644)
2008 50%	(158,077)	0%	35%	-	(55,327)	(55,327)
2009	(1,241,979)	0%	35%	-	(434,693)	(434,693)
2009 50%	978,451	0%	35%	-	342,458	342,458
2010	130,796	0%	35%	-	45,779	45,779
2010 100%	(455,600)	0%	35%	-	(159,460)	(159,460)
2010 50%	350,579	0%	35%	-	122,703	122,703
2011	(2,910,337)	0%	35%	-	(1,018,618)	(1,018,618)
2011 100%	(1,976,325)	0%	35%	-	(691,714)	(691,714)
2011 50%	(33,989)	0%	35%	-	(11,896)	(11,896)
2012	(288,003)	0%	35%	-	(100,801)	(100,801)
2012 50%	(602,155)	0%	35%	-	(210,754)	(210,754)
2013	88,425	0%	35%	-	30,949	30,949
2013 50%	455,408	0%	35%	-	159,393	159,393
2014	(224,897)	0%	35%	-	(78,714)	(78,714)
Reversal Non-TMI	(29,512,402)			**-**	**(10,468,308)**	**(10,468,308)**
Total Net Provison - Non-TMI				**-**	**13,509,689**	**13,509,689**

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service April, 2013 - March, 2014
Deferred Income Taxes Related to Gains/Losses

Vintage Year	Per Power Tax Report 52 Basis of Property	Accumulated Tax Depreciation	(Gain)/Loss recognized	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
	1	2	3	4	5	6 = 3 x 4	7 =3 x 5	8 = 6+7
Provision - 4/13-3/14								
1987	317,244	316,641	602	0%	35%	-	211	211
1988	263,933	253,188	10,745	0%	35%	-	3,761	3,761
1989	357,749	356,803	946	0%	35%	-	331	331
1990	893,880	892,229	1,652	0%	35%	-	578	578
1991	398,725	393,792	4,933	0%	35%	-	1,726	1,726
1992	336,196	333,854	2,342	0%	35%	-	820	820
1993	449,618	438,456	11,162	0%	35%	-	3,907	3,907
1994	335,669	318,868	16,800	0%	35%	-	5,880	5,880
1995	1,060,613	965,673	94,940	0%	35%	-	33,229	33,229
1996	721,828	635,561	86,267	0%	35%	-	30,193	30,193
1997	413,505	346,155	67,350	0%	35%	-	23,573	23,573
1998	899,997	714,414	185,583	0%	35%	-	64,954	64,954
1999	420,800	312,553	108,247	0%	35%	-	37,887	37,887
2000	258,751	184,330	74,421	0%	35%	-	26,047	26,047
2001	233,836	153,629	80,207	0%	35%	-	28,072	28,072
2001 30%	7,609	5,017	2,592	0%	35%	-	907	907
2002	24,205	16,041	8,164	0%	35%	-	2,857	2,857
2002 30%	70,722	43,303	27,418	0%	35%	-	9,596	9,596
2003	3,240	1,722	1,518	0%	35%	-	531	531
2003 30%	269,391	152,678	116,712	0%	35%	-	40,849	40,849
2003 50%	26,390	15,064	11,326	0%	35%	-	3,964	3,964
2004	(831)	888	(1,719)	0%	35%	-	(602)	(602)
2004 30%	59,850	32,300	27,550	0%	35%	-	9,643	9,643
2004 50%	29,922	15,889	14,034	0%	35%	-	4,912	4,912
2005	249,780	119,173	130,607	0%	35%	-	45,712	45,712
2006	328,810	141,976	186,834	0%	35%	-	65,392	65,392
2007	351,003	139,239	211,764	0%	35%	-	74,117	74,117
2008	69,404	24,967	44,437	0%	35%	-	15,553	15,553
2008 50%	124,233	43,819	80,414	0%	35%	-	28,145	28,145
2009	81,761	48,734	33,027	0%	35%	-	11,559	11,559
2009 50%	243,575	73,291	170,284	0%	35%	-	59,599	59,599
2010	2,208	1,326	881	0%	35%	-	308	308
2010 100%	-	-	-	0%	35%	-	-	-
2010 50%	170,232	67,424	102,808	0%	35%	-	35,983	35,983
2011	51,287	9,330	41,957	0%	35%	-	14,685	14,685
2011 100%	-	-	-	0%	35%	-	-	-
2011 50%	93,202	52,392	40,810	0%	35%	-	14,283	14,283
2012	89,609	6,648	82,961	0%	35%	-	29,036	29,036
2012 50%	722,465	55,881	666,583	0%	35%	-	233,304	233,304
2013	85,276	1,479	83,797	0%	35%	-	29,329	29,329
2013 50%	229,163	3,729	225,434	0%	35%	-	78,902	78,902
Provision - Non-TMI (gains/losses)							1,069,737	1,069,737

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - TMI #2
Based upon Electric Plant in Service April, 2013 - March, 2014

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Deferral of Taxes State	Federal	Total
Provision				
1978	-	-	-	-
1979	-	-	-	-
1980	-	-	-	-
1981	99	-	35	35
1982	-	-	-	-
1983	-	-	-	-
1984	-	-	-	-
1985	-	-	-	-
1986	-	-	-	-
1987	-	-	-	-
1988	-	-	-	-
1989	-	-	-	-
1992	-	-	-	-
	99	-	35	35

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Deferral of Taxes State	Federal	Total
Reversal				
1978	47,517	-	22,808	22,808
1979	56,758	-	26,109	26,109
1980	117,870	-	54,220	54,220
1981	(3)	-	1,228	1,228
1982	-	-	224	224
1983	-	-	813	813
1984	-	-	387	387
1985	-	-	809	809
1986	-	-	291	291
1987	-	-	2,168	2,168
1988	-	-	(1)	(1)
1989	-	-	(1)	(1)
1992	-	-	(322)	(322)
	222,142	-	108,734	108,734

METROPOLITAN EDISON COMPANY
Summary of Deferred Income Taxes
Based upon Electric Plant in Service April, 2014 - April, 2015

		Deferral of Taxes			Pro Forma Under Present Rates	
	Vintage Year	State	Federal	Total	Normalizing Adjustments	Total
Provision:	1970	-	-	-		-
	1971	-	-	-		-
	1972	-	745	745		745
	1973	-	1,309	1,309		1,309
	1974	-	2	2		2
	1975	-	293	293		293
	1976	-	291	291		291
	1977	-	161	161		161
	1978	-	3,239	3,239		3,239
	1979	-	657	657		657
	1980	-	567	567		567
	1981	-	1,376	1,376		1,376
	1982	-	1,669	1,669		1,669
	1983	-	2,164	2,164		2,164
	1984	-	2,304	2,304		2,304
	1985	-	2,698	2,698		2,698
	1986	-	3,187	3,187		3,187
	1987	-	10,734	10,734		10,734
	1988	-	19,751	19,751		19,751
	1989	-	19,635	19,635		19,635
	1990	-	20,718	20,718		20,718
	1991	-	111,593	111,593		111,593
	1992	-	17,367	17,367		17,367
	1993	-	12,286	12,286		12,286
	1994	-	124,974	124,974		124,974
	1995	-	452,679	452,679		452,679
	1996	-	337,405	337,405		337,405
	1997	-	535,769	535,769		535,769
	1998	-	658,098	658,098		658,098
	1999	-	381,272	381,272		381,272
	2000	-	513,426	513,426		513,426
	2001	-	539,087	539,087		539,087
	2001 30%	-	24,269	24,269		24,269
	2002	-	87,032	87,032		87,032
	2002 30%	-	176,487	176,487		176,487
	2003	-	5,172	5,172		5,172
	2003 30%	-	97,205	97,205		97,205
	2003 50%	-	62,415	62,415		62,415
	2004	-	(9,913)	(9,913)		(9,913)
	2004 30%	-	198,213	198,213		198,213
	2004 50%	-	60,765	60,765		60,765
	2005	-	462,623	462,623		462,623
	2006	-	944,154	944,154		944,154
	2007	-	878,976	878,976		878,976
	2008	-	325,382	325,382		325,382
	2008 50%	-	264,184	264,184		264,184
	2009	-	358,251	358,251		358,251
	2009 50%	-	697,076	697,076		697,076
	2010	-	(35,423)	(35,423)		(35,423)
	2010 100%	-	-	-		-
	2010 50%	-	325,477	325,477		325,477
	2011	-	366,972	366,972		366,972
	2011 100%	-	-	-		-
	2011 50%	-	45,722	45,722		45,722
	2012	-	136,217	136,217		136,217
	2012 50%	-	1,134,495	1,134,495		1,134,495
	2013	-	384,597	384,597		384,597
	2013 50%	-	641,658	641,658		641,658
	2014	-	7,620,876	7,620,876		7,620,876
	2015	-	3,711,808	3,711,808		3,711,808
Total Provision		-	22,740,145	22,740,145	-	22,740,145

METROPOLITAN EDISON COMPANY
Summary of Deferred Income Taxes
Based upon Electric Plant in Service April, 2014 - April, 2015

Vintage Year	Deferral of Taxes State	Deferral of Taxes Federal	Total	Pro Forma Under Present Rates: Normalizing Adjustments	Pro Forma Under Present Rates: Total
Reversal					
1970	-	(4,853)	(4,853)		(4,853)
1971	-	(16,071)	(16,071)		(16,071)
1972	-	(13,689)	(13,689)		(13,689)
1973	-	(15,539)	(15,539)		(15,539)
1974	-	(16,915)	(16,915)		(16,915)
1975	-	(7,464)	(7,464)		(7,464)
1976	-	(71,662)	(71,662)		(71,662)
1977	-	(14,979)	(14,979)		(14,979)
1978	-	16,252	16,252		16,252
1979	-	22,160	22,160		22,160
1980	-	44,274	44,274		44,274
1981	-	(82,271)	(82,271)		(82,271)
1982	-	(89,611)	(89,611)		(89,611)
1983	-	(147,188)	(147,188)		(147,188)
1984	-	(145,200)	(145,200)		(145,200)
1985	-	(215,727)	(215,727)		(215,727)
1986	-	(241,138)	(241,138)		(241,138)
1987	-	(245,412)	(245,412)		(245,412)
1988	-	(253,339)	(253,339)		(253,339)
1989	-	(292,662)	(292,662)		(292,662)
1990	-	(335,497)	(335,497)		(335,497)
1991	-	(327,227)	(327,227)		(327,227)
1992	-	(322,355)	(322,355)		(322,355)
1993	-	(317,478)	(317,478)		(317,478)
1994	-	(256,920)	(256,920)		(256,920)
1995	-	(405,394)	(405,394)		(405,394)
1996	-	(300,725)	(300,725)		(300,725)
1997	-	(383,294)	(383,294)		(383,294)
1998	-	(463,536)	(463,536)		(463,536)
1999	-	(290,122)	(290,122)		(290,122)
2000	-	(356,402)	(356,402)		(356,402)
2001	-	(345,526)	(345,526)		(345,526)
2001 30%	-	(451)	(451)		(451)
2002	-	(181,516)	(181,516)		(181,516)
2002 30%	-	47,482	47,482		47,482
2003	-	(181,535)	(181,535)		(181,535)
2003 30%	-	30,673	30,673		30,673
2003 50%	-	11,192	11,192		11,192
2004	-	(292,960)	(292,960)		(292,960)
2004 30%	-	(3,809)	(3,809)		(3,809)
2004 50%	-	109,301	109,301		109,301
2005	-	(20,084)	(20,084)		(20,084)
2006	-	(549,874)	(549,874)		(549,874)
2007	-	(730,277)	(730,277)		(730,277)
2008	-	(343,389)	(343,389)		(343,389)
2008 50%	-	(56,642)	(56,642)		(56,642)
2009	-	(430,221)	(430,221)		(430,221)
2009 50%	-	347,392	347,392		347,392
2010	-	53,969	53,969		53,969
2010 100%	-	(135,766)	(135,766)		(135,766)
2010 50%	-	59,335	59,335		59,335
2011	-	(1,023,862)	(1,023,862)		(1,023,862)
2011 100%	-	(600,376)	(600,376)		(600,376)
2011 50%	-	(48,495)	(48,495)		(48,495)
2012	-	(109,046)	(109,046)		(109,046)
2012 50%	-	(195,393)	(195,393)		(195,393)
2013	-	45,787	45,787		45,787
2013 50%	-	233,831	233,831		233,831
2014	-	(424,122)	(424,122)		(424,122)
2015	-	(52,315)	(52,315)		(52,315)
Total Reversal	-	(10,336,688)	(10,336,688)	-	(10,336,688)
Net Provision	-	12,403,457	12,403,457	-	12,403,457

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service April, 2014 - April, 2015

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
Provision						
1970	-	0%	35%	-	-	-
1971	-	0%	35%	-	-	-
1972	2,128	0%	35%	-	745	745
1973	3,741	0%	35%	-	1,309	1,309
1974	5	0%	35%	-	2	2
1975	836	0%	35%	-	293	293
1976	833	0%	35%	-	291	291
1977	460	0%	35%	-	161	161
1978	9,253	0%	35%	-	3,239	3,239
1979	1,878	0%	35%	-	657	657
1980	1,620	0%	35%	-	567	567
1981	3,822	0%	35%	-	1,338	1,338
1982	4,769	0%	35%	-	1,669	1,669
1983	6,183	0%	35%	-	2,164	2,164
1984	6,582	0%	35%	-	2,304	2,304
1985	7,710	0%	35%	-	2,698	2,698
1986	9,106	0%	35%	-	3,187	3,187
1987	28,225	0%	35%	-	9,879	9,879
1988	52,237	0%	35%	-	18,283	18,283
1989	52,272	0%	35%	-	18,295	18,295
1990	52,421	0%	35%	-	18,347	18,347
1991	298,884	0%	35%	-	104,609	104,609
1992	39,917	0%	35%	-	13,971	13,971
1993	5,598	0%	35%	-	1,959	1,959
1994	332,536	0%	35%	-	116,388	116,388
1995	1,271,677	0%	35%	-	445,087	445,087
1996	941,117	0%	35%	-	329,391	329,391
1997	1,495,439	0%	35%	-	523,404	523,404
1998	1,834,332	0%	35%	-	642,016	642,016
1999	1,058,754	0%	35%	-	370,564	370,564
2000	1,420,461	0%	35%	-	497,161	497,161
2001	1,481,935	0%	35%	-	518,677	518,677
2001 30%	65,984	0%	35%	-	23,095	23,095
2002	236,947	0%	35%	-	82,931	82,931
2002 30%	474,454	0%	35%	-	166,059	166,059
2003	8,953	0%	35%	-	3,133	3,133
2003 30%	259,746	0%	35%	-	90,911	90,911
2003 50%	162,008	0%	35%	-	56,703	56,703
2004	(20,853)	0%	35%	-	(7,299)	(7,299)
2004 30%	528,214	0%	35%	-	184,875	184,875
2004 50%	149,566	0%	35%	-	52,348	52,348
2005	1,176,219	0%	35%	-	411,677	411,677
2006	2,526,278	0%	35%	-	884,197	884,197
2007	2,338,924	0%	35%	-	818,623	818,623
2008	864,897	0%	35%	-	302,714	302,714
2008 50%	665,761	0%	35%	-	233,017	233,017
2009	962,706	0%	35%	-	336,947	336,947
2009 50%	1,786,413	0%	35%	-	625,245	625,245
2010	(102,643)	0%	35%	-	(35,925)	(35,925)
2010 100%	-	0%	35%	-	-	-
2010 50%	824,151	0%	35%	-	288,453	288,453
2011	1,004,758	0%	35%	-	351,665	351,665
2011 100%	-	0%	35%	-	-	-
2011 50%	119,173	0%	35%	-	41,710	41,710
2012	364,290	0%	35%	-	127,501	127,501
2012 50%	3,049,214	0%	35%	-	1,067,225	1,067,225
2013	1,028,742	0%	35%	-	360,060	360,060
2013 50%	1,684,396	0%	35%	-	589,539	589,539
2014	21,688,106	0%	35%	-	7,590,837	7,590,837
2015	10,605,166	0%	35%	-	3,711,808	3,711,808
	62,876,298			-	22,006,704	22,006,704
Provision Gains/Losses Page (12)				**-**	**733,403**	**733,403**
Provision - Non - TMI				**-**	**22,740,107**	**22,740,107**

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service April, 2014 - April, 2015

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
Reversal						
1970	(10,147)	0%	48%	-	(4,853)	(4,853)
1971	(33,520)	0%	48%	-	(16,071)	(16,071)
1972	(28,652)	0%	48%	-	(13,689)	(13,689)
1973	(32,424)	0%	48%	-	(15,539)	(15,539)
1974	(35,302)	0%	48%	-	(16,915)	(16,915)
1975	(15,587)	0%	48%	-	(7,464)	(7,464)
1976	(149,363)	0%	48%	-	(71,662)	(71,662)
1977	(31,303)	0%	48%	-	(14,979)	(14,979)
1978	(13,986)	0%	48%	-	(6,653)	(6,653)
1979	(8,882)	0%	46%	-	(4,060)	(4,060)
1980	(22,202)	0%	46%	-	(10,177)	(10,177)
1981	(198,725)	0%	42%	-	(83,504)	(83,504)
1982	(221,510)	0%	41%	-	(89,837)	(89,837)
1983	(370,832)	0%	40%	-	(148,004)	(148,004)
1984	(374,089)	0%	39%	-	(145,589)	(145,589)
1985	(565,347)	0%	38%	-	(216,540)	(216,540)
1986	(655,399)	0%	37%	-	(241,431)	(241,431)
1987	(708,199)	0%	35%	-	(247,589)	(247,589)
1988	(727,302)	0%	35%	-	(253,338)	(253,338)
1989	(839,669)	0%	35%	-	(292,662)	(292,662)
1990	(967,688)	0%	35%	-	(335,497)	(335,497)
1991	(939,179)	0%	35%	-	(327,227)	(327,227)
1992	(920,041)	0%	35%	-	(322,032)	(322,032)
1993	(907,080)	0%	35%	-	(317,478)	(317,478)
1994	(734,056)	0%	35%	-	(256,920)	(256,920)
1995	(1,158,268)	0%	35%	-	(405,394)	(405,394)
1996	(859,214)	0%	35%	-	(300,725)	(300,725)
1997	(1,095,126)	0%	35%	-	(383,294)	(383,294)
1998	(1,324,389)	0%	35%	-	(463,536)	(463,536)
1999	(828,921)	0%	35%	-	(290,122)	(290,122)
2000	(1,018,291)	0%	35%	-	(356,402)	(356,402)
2001	(987,216)	0%	35%	-	(345,526)	(345,526)
2001 30%	(1,287)	0%	35%	-	(451)	(451)
2002	(518,617)	0%	35%	-	(181,516)	(181,516)
2002 30%	135,662	0%	35%	-	47,482	47,482
2003	(518,673)	0%	35%	-	(181,535)	(181,535)
2003 30%	87,636	0%	35%	-	30,673	30,673
2003 50%	31,977	0%	35%	-	11,192	11,192
2004	(837,030)	0%	35%	-	(292,960)	(292,960)
2004 30%	(10,883)	0%	35%	-	(3,809)	(3,809)
2004 50%	312,288	0%	35%	-	109,301	109,301
2005	(57,383)	0%	35%	-	(20,084)	(20,084)
2006	(1,571,069)	0%	35%	-	(549,874)	(549,874)
2007	(2,086,507)	0%	35%	-	(730,277)	(730,277)
2008	(981,111)	0%	35%	-	(343,389)	(343,389)
2008 50%	(161,835)	0%	35%	-	(56,642)	(56,642)
2009	(1,229,202)	0%	35%	-	(430,221)	(430,221)
2009 50%	992,547	0%	35%	-	347,392	347,392
2010	154,197	0%	35%	-	53,969	53,969
2010 100%	(387,902)	0%	35%	-	(135,766)	(135,766)
2010 50%	169,528	0%	35%	-	59,335	59,335
2011	(2,925,319)	0%	35%	-	(1,023,862)	(1,023,862)
2011 100%	(1,715,360)	0%	35%	-	(600,376)	(600,376)
2011 50%	(138,556)	0%	35%	-	(48,495)	(48,495)
2012	(311,560)	0%	35%	-	(109,046)	(109,046)
2012 50%	(558,267)	0%	35%	-	(195,393)	(195,393)
2013	130,820	0%	35%	-	45,787	45,787
2013 50%	668,087	0%	35%	-	233,831	233,831
2014	(1,211,777)	0%	35%	-	(424,122)	(424,122)
2015	(149,473)	0%	35%	-	(52,315)	(52,315)
Reversal Non-TMI	(29,470,979)			**-**	**(10,445,884)**	**(10,445,884)**
Total Net Provison - Non-TMI				**-**	**12,294,223**	**12,294,223**

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service April, 2014 - April, 2015
Deferred Income Taxes Related to Gains/Losses

Vintage Year	Per Power Tax Report 52 Basis of Property	Accumulated Tax Depreciation	(Gain)/Loss recognized	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
	1	2	3	4	5	6 = 3 x 4	7 =3 x 5	8 = 6+7
Provision - 4/14-4/15								
1987	181,423	178,979	2,445	0%	35%	-	856	856
1988	191,025	186,830	4,195	0%	35%	-	1,468	1,468
1989	223,391	219,562	3,829	0%	35%	-	1,340	1,340
1990	238,097	231,323	6,774	0%	35%	-	2,371	2,371
1991	308,466	288,514	19,952	0%	35%	-	6,983	6,983
1992	271,570	261,868	9,703	0%	35%	-	3,396	3,396
1993	274,339	244,833	29,505	0%	35%	-	10,327	10,327
1994	250,165	225,632	24,533	0%	35%	-	8,587	8,587
1995	241,924	220,233	21,692	0%	35%	-	7,592	7,592
1996	154,881	131,985	22,897	0%	35%	-	8,014	8,014
1997	224,494	189,165	35,329	0%	35%	-	12,365	12,365
1998	267,265	221,318	45,948	0%	35%	-	16,082	16,082
1999	143,528	112,934	30,594	0%	35%	-	10,708	10,708
2000	213,433	166,963	46,470	0%	35%	-	16,264	16,264
2001	203,435	145,121	58,314	0%	35%	-	20,410	20,410
2001 30%	11,251	7,895	3,356	0%	35%	-	1,175	1,175
2002	45,827	34,112	11,715	0%	35%	-	4,100	4,100
2002 30%	86,630	56,836	29,794	0%	35%	-	10,428	10,428
2003	12,637	6,814	5,823	0%	35%	-	2,038	2,038
2003 30%	72,238	54,254	17,984	0%	35%	-	6,294	6,294
2003 50%	41,962	25,641	16,321	0%	35%	-	5,712	5,712
2004	(4,365)	3,104	(7,469)	0%	35%	-	(2,614)	(2,614)
2004 30%	90,256	52,147	38,109	0%	35%	-	13,338	13,338
2004 50%	55,924	31,875	24,049	0%	35%	-	8,417	8,417
2005	301,965	156,404	145,561	0%	35%	-	50,946	50,946
2006	328,674	157,369	171,305	0%	35%	-	59,957	59,957
2007	336,091	163,654	172,436	0%	35%	-	60,353	60,353
2008	107,837	43,072	64,765	0%	35%	-	22,668	22,668
2008 50%	147,507	58,457	89,050	0%	35%	-	31,168	31,168
2009	98,122	37,253	60,869	0%	35%	-	21,304	21,304
2009 50%	320,398	115,166	205,232	0%	35%	-	71,831	71,831
2010	6,694	5,258	1,436	0%	35%	-	503	503
2010 100%	-	-	-	0%	35%	-	-	-
2010 50%	156,471	50,689	105,782	0%	35%	-	37,024	37,024
2011	54,577	10,845	43,732	0%	35%	-	15,306	15,306
2011 100%	-	-	-	0%	35%	-	-	-
2011 50%	21,842	10,381	11,461	0%	35%	-	4,011	4,011
2012	29,169	4,268	24,901	0%	35%	-	8,715	8,715
2012 50%	223,501	31,300	192,201	0%	35%	-	67,270	67,270
2013	77,816	7,711	70,105	0%	35%	-	24,537	24,537
2013 50%	168,444	19,532	148,912	0%	35%	-	52,119	52,119
2014	100,037	14,212	85,825	0%	35%	-	30,039	30,039
Provision - Non-TMI (gains/losses)							733,403	733,403

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - TMI #2
Based upon Electric Plant in Service April, 2014 - April, 2015

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Deferral of Taxes State	Federal	Total
Provision				
1978	-	-	-	-
1979	-	-	-	-
1980	-	-	-	-
1981	108	-	38	38
1982	-	-	-	-
1983	-	-	-	-
1984	-	-	-	-
1985	-	-	-	-
1986	-	-	-	-
1987	-	-	-	-
1988	-	-	-	-
1989	-	-	-	-
1992	-	-	-	-
	108	-	38	38

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Deferral of Taxes State	Federal	Total
Reversal				
1978	47,719	-	22,905	22,905
1979	56,999	-	26,220	26,220
1980	118,371	-	54,450	54,450
1981	(3)	-	1,233	1,233
1982	-	-	225	225
1983	-	-	817	817
1984	-	-	389	389
1985	-	-	813	813
1986	-	-	292	292
1987	-	-	2,177	2,177
1988	-	-	(1)	(1)
1989	-	-	(1)	(1)
1992	-	-	(324)	(324)
	223,086	-	109,196	109,196

METROPOLITAN EDISON COMPANY
Summary of Deferred Income Taxes
Based upon Electric Plant in Service May, 2015 - April, 2016

		Deferral of Taxes		
	Vintage Year	State	Federal	Total
Provision:	1970	-	-	-
	1971	-	-	-
	1972	-	-	-
	1973	-	459	459
	1974	-	0	0
	1975	-	38	38
	1976	-	80	80
	1977	-	55	55
	1978	-	1,136	1,136
	1979	-	230	230
	1980	-	199	199
	1981	-	171	171
	1982	-	206	206
	1983	-	268	268
	1984	-	302	302
	1985	-	350	350
	1986	-	440	440
	1987	-	2,252	2,252
	1988	-	4,480	4,480
	1989	-	4,498	4,498
	1990	-	4,718	4,718
	1991	-	26,911	26,911
	1992	-	3,847	3,847
	1993	-	(200)	(200)
	1994	-	(568)	(568)
	1995	-	14,381	14,381
	1996	-	69,573	69,573
	1997	-	156,507	156,507
	1998	-	194,671	194,671
	1999	-	112,429	112,429
	2000	-	152,218	152,218
	2001	-	159,620	159,620
	2001 30%	-	6,093	6,093
	2002	-	26,783	26,783
	2002 30%	-	46,034	46,034
	2003	-	1,568	1,568
	2003 30%	-	26,020	26,020
	2003 50%	-	8,397	8,397
	2004	-	(3,326)	(3,326)
	2004 30%	-	48,681	48,681
	2004 50%	-	12,693	12,693
	2005	-	128,637	128,637
	2006	-	282,124	282,124
	2007	-	256,951	256,951
	2008	-	94,243	94,243
	2008 50%	-	36,844	36,844
	2009	-	107,970	107,970
	2009 50%	-	131,368	131,368
	2010	-	(6,253)	(6,253)
	2010 100%	-	-	-
	2010 50%	-	53,652	53,652
	2011	-	69,435	69,435
	2011 100%	-	-	-
	2011 50%	-	9,907	9,907
	2012	-	33,918	33,918
	2012 50%	-	238,042	238,042
	2013	-	102,234	102,234
	2013 50%	-	127,530	127,530
	2014	-	1,310,796	1,310,796
	2015	-	2,904,167	2,904,167
	2016	-	1,877,566	1,877,566
Total Provision		-	8,841,345	8,841,345

METROPOLITAN EDISON COMPANY
Summary of Deferred Income Taxes
Based upon Electric Plant in Service May, 2015 - April, 2016

		Deferral of Taxes		
	Vintage Year	State	Federal	Total
Reversal				
	1970	-	(1,797)	(1,797)
	1971	-	(6,201)	(6,201)
	1972	-	(5,540)	(5,540)
	1973	-	(5,932)	(5,932)
	1974	-	(6,307)	(6,307)
	1975	-	(2,939)	(2,939)
	1976	-	(27,094)	(27,094)
	1977	-	(5,680)	(5,680)
	1978	-	6,148	6,148
	1979	-	8,376	8,376
	1980	-	16,738	16,738
	1981	-	(37,034)	(37,034)
	1982	-	(40,260)	(40,260)
	1983	-	(66,768)	(66,768)
	1984	-	(64,795)	(64,795)
	1985	-	(98,292)	(98,292)
	1986	-	(108,896)	(108,896)
	1987	-	(110,694)	(110,694)
	1988	-	(113,404)	(113,404)
	1989	-	(131,748)	(131,748)
	1990	-	(151,549)	(151,549)
	1991	-	(148,229)	(148,229)
	1992	-	(146,362)	(146,362)
	1993	-	(146,582)	(146,582)
	1994	-	(135,448)	(135,448)
	1995	-	(104,984)	(104,984)
	1996	-	(91,467)	(91,467)
	1997	-	(138,071)	(138,071)
	1998	-	(168,603)	(168,603)
	1999	-	(103,278)	(103,278)
	2000	-	(126,940)	(126,940)
	2001	-	(123,454)	(123,454)
	2001 30%	-	(175)	(175)
	2002	-	(64,747)	(64,747)
	2002 30%	-	17,476	17,476
	2003	-	(64,688)	(64,688)
	2003 30%	-	10,106	10,106
	2003 50%	-	3,868	3,868
	2004	-	(103,351)	(103,351)
	2004 30%	-	(2,416)	(2,416)
	2004 50%	-	36,619	36,619
	2005	-	(16,229)	(16,229)
	2006	-	(194,785)	(194,785)
	2007	-	(231,514)	(231,514)
	2008	-	(116,315)	(116,315)
	2008 50%	-	(23,063)	(23,063)
	2009	-	(135,843)	(135,843)
	2009 50%	-	128,431	128,431
	2010	-	14,538	14,538
	2010 100%	-	(61,151)	(61,151)
	2010 50%	-	15,027	15,027
	2011	-	(393,293)	(393,293)
	2011 100%	-	(267,620)	(267,620)
	2011 50%	-	(41,994)	(41,994)
	2012	-	(43,799)	(43,799)
	2012 50%	-	(73,522)	(73,522)
	2013	-	13,645	13,645
	2013 50%	-	66,781	66,781
	2014	-	(197,903)	(197,903)
	2015	-	(82,441)	(82,441)
	2016	-	(16,191)	(16,191)
Total Reversal		-	(4,211,636)	(4,211,636)
Net Provision		-	4,629,710	4,629,710

METROPOLITAN EDISON COMPANY
Computation of Deferred Icome Taxes - Non - TMI
Based upon Electric Plant in Service May, 2015 - April, 2016

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
Provision						
1970	-	0%	35%	-	-	-
1971	-	0%	35%	-	-	-
1972	-	0%	35%	-	-	-
1973	1,310	0%	35%	-	459	459
1974	0	0%	35%	-	0	0
1975	109	0%	35%	-	38	38
1976	227	0%	35%	-	80	80
1977	158	0%	35%	-	55	55
1978	3,247	0%	35%	-	1,136	1,136
1979	657	0%	35%	-	230	230
1980	569	0%	35%	-	199	199
1981	463	0%	35%	-	162	162
1982	588	0%	35%	-	206	206
1983	765	0%	35%	-	268	268
1984	862	0%	35%	-	302	302
1985	1,001	0%	35%	-	350	350
1986	1,257	0%	35%	-	440	440
1987	5,705	0%	35%	-	1,997	1,997
1988	11,541	0%	35%	-	4,039	4,039
1989	11,721	0%	35%	-	4,102	4,102
1990	11,364	0%	35%	-	3,977	3,977
1991	71,021	0%	35%	-	24,857	24,857
1992	7,831	0%	35%	-	2,741	2,741
1993	(10,332)	0%	35%	-	(3,616)	(3,616)
1994	(9,199)	0%	35%	-	(3,220)	(3,220)
1995	35,853	0%	35%	-	12,549	12,549
1996	192,920	0%	35%	-	67,522	67,522
1997	438,449	0%	35%	-	153,457	153,457
1998	544,337	0%	35%	-	190,518	190,518
1999	313,108	0%	35%	-	109,588	109,588
2000	422,195	0%	35%	-	147,768	147,768
2001	439,512	0%	35%	-	153,829	153,829
2001 30%	16,461	0%	35%	-	5,761	5,761
2002	73,070	0%	35%	-	25,574	25,574
2002 30%	122,897	0%	35%	-	43,014	43,014
2003	2,670	0%	35%	-	935	935
2003 30%	69,036	0%	35%	-	24,162	24,162
2003 50%	19,176	0%	35%	-	6,711	6,711
2004	(6,900)	0%	35%	-	(2,415)	(2,415)
2004 30%	127,681	0%	35%	-	44,688	44,688
2004 50%	29,067	0%	35%	-	10,174	10,174
2005	323,204	0%	35%	-	113,121	113,121
2006	753,644	0%	35%	-	263,776	263,776
2007	681,107	0%	35%	-	238,388	238,388
2008	249,228	0%	35%	-	87,230	87,230
2008 50%	77,721	0%	35%	-	27,202	27,202
2009	289,835	0%	35%	-	101,442	101,442
2009 50%	312,154	0%	35%	-	109,254	109,254
2010	(17,999)	0%	35%	-	(6,300)	(6,300)
2010 100%	-	0%	35%	-	-	-
2010 50%	120,586	0%	35%	-	42,205	42,205
2011	184,631	0%	35%	-	64,621	64,621
2011 100%	-	0%	35%	-	-	-
2011 50%	24,876	0%	35%	-	8,707	8,707
2012	89,108	0%	35%	-	31,188	31,188
2012 50%	619,811	0%	35%	-	216,934	216,934
2013	270,374	0%	35%	-	94,631	94,631
2013 50%	319,073	0%	35%	-	111,676	111,676
2014	3,647,605	0%	35%	-	1,276,662	1,276,662
2015	8,265,759	0%	35%	-	2,893,016	2,893,016
2016	5,364,474	0%	35%	-	1,877,566	1,877,566
	24,525,590			-	8,583,957	8,583,957
Provison Gains/Losses Page (18)				**-**	**257,380**	**257,380**
Provision - Non -TMI				**-**	**8,841,336**	**8,841,336**

METROPOLITAN EDISON COMPANY
Computation of Deferred Icome Taxes - Non - TMI
Based upon Electric Plant in Service May, 2015 - April, 2016

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
Reversal						
1970	(3,758)	0%	48%	-	(1,797)	(1,797)
1971	(12,936)	0%	48%	-	(6,201)	(6,201)
1972	(11,758)	0%	47%	-	(5,540)	(5,540)
1973	(12,379)	0%	48%	-	(5,932)	(5,932)
1974	(13,164)	0%	48%	-	(6,307)	(6,307)
1975	(6,156)	0%	48%	-	(2,939)	(2,939)
1976	(56,473)	0%	48%	-	(27,094)	(27,094)
1977	(11,873)	0%	48%	-	(5,680)	(5,680)
1978	(5,309)	0%	48%	-	(2,524)	(2,524)
1979	(3,396)	0%	46%	-	(1,551)	(1,551)
1980	(8,464)	0%	46%	-	(3,878)	(3,878)
1981	(89,712)	0%	42%	-	(37,501)	(37,501)
1982	(99,677)	0%	40%	-	(40,345)	(40,345)
1983	(168,538)	0%	40%	-	(67,077)	(67,077)
1984	(167,378)	0%	39%	-	(64,943)	(64,943)
1985	(259,020)	0%	38%	-	(98,599)	(98,599)
1986	(297,546)	0%	37%	-	(109,007)	(109,007)
1987	(319,571)	0%	35%	-	(111,519)	(111,519)
1988	(326,233)	0%	35%	-	(113,404)	(113,404)
1989	(378,646)	0%	35%	-	(131,747)	(131,747)
1990	(436,982)	0%	35%	-	(151,549)	(151,549)
1991	(425,403)	0%	35%	-	(148,229)	(148,229)
1992	(417,870)	0%	35%	-	(146,239)	(146,239)
1993	(418,805)	0%	35%	-	(146,582)	(146,582)
1994	(386,994)	0%	35%	-	(135,448)	(135,448)
1995	(299,955)	0%	35%	-	(104,984)	(104,984)
1996	(261,333)	0%	35%	-	(91,467)	(91,467)
1997	(394,489)	0%	35%	-	(138,071)	(138,071)
1998	(481,724)	0%	35%	-	(168,603)	(168,603)
1999	(295,081)	0%	35%	-	(103,278)	(103,278)
2000	(362,686)	0%	35%	-	(126,940)	(126,940)
2001	(352,725)	0%	35%	-	(123,454)	(123,454)
2001 30%	(500)	0%	35%	-	(175)	(175)
2002	(184,992)	0%	35%	-	(64,747)	(64,747)
2002 30%	49,931	0%	35%	-	17,476	17,476
2003	(184,822)	0%	35%	-	(64,688)	(64,688)
2003 30%	28,873	0%	35%	-	10,106	10,106
2003 50%	11,052	0%	35%	-	3,868	3,868
2004	(295,290)	0%	35%	-	(103,351)	(103,351)
2004 30%	(6,901)	0%	35%	-	(2,416)	(2,416)
2004 50%	104,624	0%	35%	-	36,619	36,619
2005	(46,369)	0%	35%	-	(16,229)	(16,229)
2006	(556,529)	0%	35%	-	(194,785)	(194,785)
2007	(661,468)	0%	35%	-	(231,514)	(231,514)
2008	(332,330)	0%	35%	-	(116,315)	(116,315)
2008 50%	(65,895)	0%	35%	-	(23,063)	(23,063)
2009	(388,122)	0%	35%	-	(135,843)	(135,843)
2009 50%	366,946	0%	35%	-	128,431	128,431
2010	41,536	0%	35%	-	14,538	14,538
2010 100%	(174,718)	0%	35%	-	(61,151)	(61,151)
2010 50%	42,935	0%	35%	-	15,027	15,027
2011	(1,123,693)	0%	35%	-	(393,293)	(393,293)
2011 100%	(764,627)	0%	35%	-	(267,620)	(267,620)
2011 50%	(119,982)	0%	35%	-	(41,994)	(41,994)
2012	(125,140)	0%	35%	-	(43,799)	(43,799)
2012 50%	(210,061)	0%	35%	-	(73,522)	(73,522)
2013	38,986	0%	35%	-	13,645	13,645
2013 50%	190,804	0%	35%	-	66,781	66,781
2014	(565,438)	0%	35%	-	(197,903)	(197,903)
2015	(235,546)	0%	35%	-	(82,441)	(82,441)
2016	(46,260)	0%	35%	-	(16,191)	(16,191)
Reversal Non-TMI	(11,999,033)			-	(4,252,981)	(4,252,981)
Total Net Provison - Non-TMI				**-**	**4,588,355**	**4,588,355**

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - Non - TMI
Based upon Electric Plant in Service May, 2015 - April, 2016
Deferred Income Taxes Related to Gains/Losses

Vintage Year	Per Power Tax Report 52 Basis of Property	Accumulated Tax Depreciation	(Gain)/Loss recognized	Statutory/ Effective Rates State	Federal	Deferral of Taxes State	Federal	Total
	1	2	3	4	5	6 = 3 x 4	7 =3 x 5	8 = 6+7
Provision - 5/15-4/16								
1987	61,111	60,381	731	0%	35%	-	256	256
1988	64,346	63,088	1,257	0%	35%	-	440	440
1989	75,248	74,118	1,130	0%	35%	-	396	396
1990	80,202	78,085	2,117	0%	35%	-	741	741
1991	103,905	98,037	5,868	0%	35%	-	2,054	2,054
1992	91,477	88,317	3,160	0%	35%	-	1,106	1,106
1993	92,410	82,647	9,762	0%	35%	-	3,417	3,417
1994	84,267	76,691	7,576	0%	35%	-	2,652	2,652
1995	81,491	76,257	5,234	0%	35%	-	1,832	1,832
1996	52,171	46,312	5,859	0%	35%	-	2,050	2,050
1997	75,620	66,904	8,715	0%	35%	-	3,050	3,050
1998	90,027	78,161	11,866	0%	35%	-	4,153	4,153
1999	48,347	40,228	8,119	0%	35%	-	2,841	2,841
2000	71,894	59,181	12,713	0%	35%	-	4,449	4,449
2001	68,526	51,981	16,545	0%	35%	-	5,791	5,791
2001 30%	3,790	2,842	947	0%	35%	-	332	332
2002	15,437	11,985	3,452	0%	35%	-	1,208	1,208
2002 30%	29,181	20,553	8,628	0%	35%	-	3,020	3,020
2003	4,257	2,446	1,811	0%	35%	-	634	634
2003 30%	24,333	19,027	5,306	0%	35%	-	1,857	1,857
2003 50%	14,135	9,319	4,816	0%	35%	-	1,686	1,686
2004	(1,470)	1,132	(2,602)	0%	35%	-	(911)	(911)
2004 30%	30,402	18,994	11,409	0%	35%	-	3,993	3,993
2004 50%	18,838	11,639	7,198	0%	35%	-	2,519	2,519
2005	101,715	57,385	44,330	0%	35%	-	15,515	15,515
2006	110,712	58,289	52,423	0%	35%	-	18,348	18,348
2007	113,210	60,172	53,039	0%	35%	-	18,564	18,564
2008	36,324	16,285	20,039	0%	35%	-	7,014	7,014
2008 50%	49,687	22,138	27,549	0%	35%	-	9,642	9,642
2009	33,052	14,402	18,650	0%	35%	-	6,527	6,527
2009 50%	107,925	44,741	63,184	0%	35%	-	22,114	22,114
2010	2,255	2,122	133	0%	35%	-	46	46
2010 100%	-	-	-	0%	35%	-	-	-
2010 50%	52,706	20,000	32,707	0%	35%	-	11,447	11,447
2011	18,384	4,630	13,754	0%	35%	-	4,814	4,814
2011 100%	-	-	-	0%	35%	-	-	-
2011 50%	7,358	3,929	3,429	0%	35%	-	1,200	1,200
2012	9,826	2,026	7,800	0%	35%	-	2,730	2,730
2012 50%	75,285	14,976	60,309	0%	35%	-	21,108	21,108
2013	26,212	4,488	21,724	0%	35%	-	7,603	7,603
2013 50%	56,739	11,441	45,298	0%	35%	-	15,854	15,854
2014	119,456	21,928	97,528	0%	35%	-	34,135	34,135
2015	37,138	5,277	31,861	0%	35%	-	11,151	11,151
Provision - Non-TMI (gains/losses)							257,380	257,380

METROPOLITAN EDISON COMPANY
Computation of Deferred Income Taxes - TMI #2
Based upon Electric Plant in Service May, 2015 - April, 2016

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Deferral of Taxes State	Federal	Total
Provision				
1978	-	-	-	-
1979	-	-	-	-
1980	-	-	-	-
1981	26	-	9	9
1982	-	-	-	-
1983	-	-	-	-
1984	-	-	-	-
1985	-	-	-	-
1986	-	-	-	-
1987	-	-	-	-
1988	-	-	-	-
1989	-	-	-	-
1992	-	-	-	-
	26	-	9	9

Vintage Year	Accelerate Tax Depreciation less Straight Line Depreciation	Deferral of Taxes State	Federal	Total
Reversal				
1978	18,068	-	22,814	8,673
1979	21,582	-	26,116	9,928
1980	44,819	-	54,235	20,617
1981	25	-	1,229	467
1982	-	-	224	85
1983	-	-	814	309
1984	-	-	387	147
1985	-	-	810	308
1986	-	-	291	111
1987	-	-	2,168	824
1988	-	-	(1)	(0)
1989	-	-	(1)	(0)
1992	-	-	(322)	(123)
	84,494	-	108,764	41,345

METROPOLITAN EDISON COMPANY
($000)

POST 1969 VINTAGES

	Per Power Tax	Pro Forma Under Present Rates Normalization Adjustment	Total
Liberalized Depreciation Deferred Taxes			
Balance per Budget 3/31/14	(460,362)		(460,362)
Balance per Budget 3/31/13	(447,575)		(447,575)
Liberalized Depreciation Activity - April, 2013 to March, 2014	(12,787)		(12,787)
Net Federal and State Provision	12,787		12,787
Less: Net State Provision (negative)	(1,279)		(1,279)
Net Federal Provision per Budget	14,066		14,066
Add: Federal Benefit (increase) of State	(448)		(448)
Net Federal - April, 2013 to March, 2014 Provision for Rates	13,618		13,618

POST 1969 VINTAGES

	Per Power Tax	Pro Forma Under Present Rates Normalization Adjustment	Total
Liberalized Depreciation Deferred Taxes			
Balance per Budget 4/30/15	(472,793)		(472,793)
Balance per Budget 3/31/14	(460,362)		(460,362)
Liberalized Depreciation Activity - April, 2014 to April, 2015	(12,431)		(12,431)
Net Federal and State Provision	12,431		12,431
Less: Net State Provision (negative)	43		43
Net Federal Provision per Budget	12,388		12,388
Add: Federal Benefit (increase) of State	15		15
Net Federal - April, 2014 to April, 2015 Provision for Rates	12,403		12,403

POST 1969 VINTAGES

	Per Power Tax	Pro Forma Under Present Rates Normalization Adjustment	Total
Liberalized Depreciation Deferred Taxes			
Balance per Budget 4/30/16	(477,639)		(477,639)
Balance per Budget 4/30/15	(472,793)		(472,793)
Liberalized Depreciation Activity - May, 2015 to April, 2016	(4,846)		(4,846)
Net Federal and State Provision	4,846		4,846
Less: Net State Provision (negative)	332		332
Net Federal Provision per Budget	4,514		4,514
Add: Federal Benefit (increase) of State	116		116
Net Federal - May, 2015 to April, 2016 Provision for Rates	4,630		4,630

Reconciliation of the Deferred Tax Balance Shown on the Rate Base and the Deferred Tax Balance on the Balance Sheet

	Met-Ed
Balance Sheet (RAD-54) @ 3/31/13	542,609
Total APB11 Deferreds on Rollforward Schedule @ 3/31/13	462,669
Difference	79,940
Reconciling Items:	
State Deferreds	-
3/31/13 Rollforward Schedule didn't tie to SAP	-
FAS 109 Gross-Up	-
FAS 109	79,940
Total Reconciling Items	79,940
Balance Sheet (RAD-54) @ 3/31/14	555,752
Adjustments needed for RAD-35	994
Adjusted Balance Sheet (RAD-35) @3/31/14	556,746
Total APB11 Deferreds on Rollforward Schedule @ 3/31/14	478,696
Difference	78,050
Reconciling Items:	
State Deferreds	-
State Offset Deferreds	-
FAS 109 Gross-Up	-
FAS 109	77,056
Smart Meters per RAD-35	310
Vegetation Management FERC Reclasses	684
Total Reconciling Items	78,050
Balance Sheet (RAD-54) @ 3/31/15	552,220
Adjustments needed for RAD-35	17,014
Adjusted Balance Sheet (RAD-35) @3/31/15	569,234
Total APB11 Deferreds on Rollforward Schedule @ 4/30/15	489,924
Difference	79,310
Reconciling Items:	
State Deferreds	-
State Offset Deferreds	-
B/S one month behind Rollforward Schedule	(864)
Smart Meters per RAD-35	996
Deferred Tax Pro-Ration on Rollforward Schedule	640
FAS 109 Gross-Up	-
FAS 109	78,538
Total Reconciling Items	79,310

Balance Sheet (RAD-54) @ 4/30/16	552,440
Adjustments needed for RAD-35	38,087
Adjusted Balance Sheet (RAD-35) @4/30/16	590,527
Total APB11 Deferreds on Rollforward Schedule @ 4/30/16	495,161
Difference	95,366
Reconciling Items:	
State Deferreds	-
State Offset Deferreds	-
B/S one month behind Rollforward Schedule	864
Smart Meters per RAD-35	2,037
Deferred Tax Pro-Ration on Rollforward Schedule	6,748
FAS 109 Gross-Up	0
FAS 109	85,717
Total Reconciling Items	95,366

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-25:

"Submit a schedule showing a breakdown of accumulated and unamortized investment tax credits, by vintage year and percentage rate, together with calculations supporting the amortized amount claimed as a reduction to pro forma income taxes. Provide details of methods used to write-off the unamortized balances."

RESPONSE:

Investment Tax Credit Balances, Provision and Amortization
($000)

	4% and 10%
Balance 3/31/13	$ 5,919
12 Months ended 3/31/14 Amortization	(398)
Balance 3/31/14	$ 5,521
12 Months ending 3/31/15 Amortization	(364)
Balance 3/31/15	$ 5,157
Amortization 1 month ending 4/30/15	(31)
Balance 4/30/15	$ 5,126
12 Months ending 4/30/16 Amortization	(364)
Balance 4/30/16	$ 4,762

Investment Tax Credit

Met-Ed is amortizing the deferred credit previously created by a ratable flow-through to income over the useful life of the property. On March 9, 1972, General Public Utilities Corporation (former parent company of respondent) filed with the District Director of Internal Revenue, Manhattan District, on behalf of its affiliated companies (Met-Ed being one of the affiliates), an election under paragraph (2) of Section 46(e) of the Internal Revenue Code of 1954, as amended, for allowance, with respect to public utility property, of the credit allowed by Section 38 of the Code. Such an election provides (a) to reduce the cost of service for ratemaking purposes or in its regulated books of account by no more than ratable portion of the credit allowable by Section 38, and (b) not to reduce the base to which its rate of return is applied for ratemaking purposes by any portion of the credit allowable by Section 38.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-26:

"Explain in detail by statement or exhibit the appropriateness of claiming any additional items, not otherwise specifically explained and supported in the statement of operating income."

RESPONSE:

The appropriateness of claiming the various items included in the statement of operating income is explained in the supporting schedules to Met-Ed Exhibit RAD-2 and the testimony and exhibits of the Company's witnesses.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-D-27:

"If the utility's operations include non-jurisdictional activities, provide a schedule which demonstrates the manner in which rate base and operating income date have been adjusted to develop the jurisdictional test year claim."

RESPONSE:

The Company does not maintain its books based on jurisdictional divisions. An allocation for PaPUC jurisdictional purposes will be supported by Met-Ed witness Hillary E. Stewart, Met-Ed Statement No. 5 through the cost of service study.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-E-1:

"Supply a copy of any budget utilized as a basis for any test year claim, and explain the utility's budgeting process."

RESPONSE:

The FirstEnergy budget guidelines details the items required for the preparation of the construction and operating budgets. See Met-Ed RAD-45 Attachment A for a review of the guidelines.

Beginning in 2014, FirstEnergy implemented a new budget and long-term planning application, UI Planner. See Met-Ed Exhibit RAD-45 Attachment B for an explanation of FirstEnergy's budget process.

A copy of the budget utilized for the test year claim is contained in Met-Ed Exhibit RAD-18.

FirstEnergy

2014 Budget Guidelines



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CHAPTER 1: INTRODUCTION

The integrated business planning process is critical to the success of FirstEnergy. A key component of this process is the annual budget which provides a method to quantify and report the current year's expectations and helps drive the enterprise toward achieving both short-term and long-term financial and operational objectives. The budget also helps facilitate the efficient usage of the Company's financial resources and allows us to measure actual performance against projections.

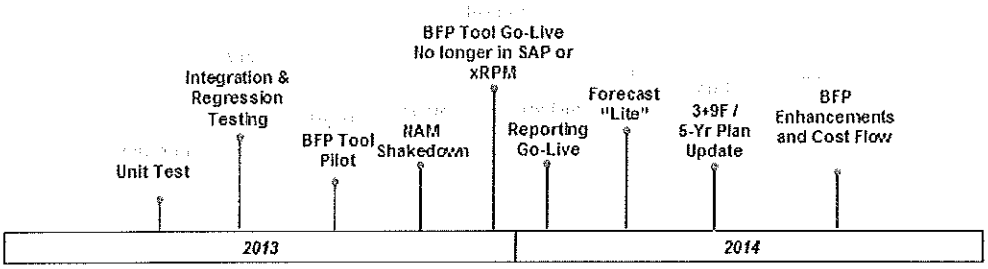
The guidelines in this booklet are intended to assist persons responsible for direct input of data into the SAP system as they prepare the 2014 annual budget. The 2014 budget should be based on your business unit's business plans and should align with Executive Council's expectations.

Business Unit Income Statements will be produced using the Profit Center Accounting module in SAP. Budget details will be developed and input using the various SAP cost collectors (i.e. cost centers, internal orders and WBSs). Through system mapping within SAP, these cost collectors are assigned to Profit Centers. Once data input is completed and the SAP system is closed, Business Unit Income Statements will be available for review. The Profit Center Hierarchy (PC0001B) serves as the source for the structure of Business Unit Income Statements). Earnings Driver reports which measure the impact and contribution of key items to the financial performance of each Business Unit will also be produced. Any questions concerning these statements should be directed to Mike Kreighbaum (825-2556) or Carrie Wokaty (825-6005).

Please Note: ***For the 2014 Forecast and the 2014 Annual Budget we will follow the same process as last year in SAP.*** *However, as part of the Financial Transformation project, we will be implementing the new Cost Accountability Model and begin doing our forecasting and budget inputs into a new financial tool, UIPlanner. Separate documentation and training for the tool will be provided through the FiT team. Below is a high level summary of the upcoming implementation timeline.*

Financial Transformation Project

Path to Implementation



Resource Activities	Date	Time Commitment
Training	August 20 – 22	~ 24 hours
BFP Pilot	Sept 2 – Oct 28	~ 10/week
Acct Model Shakedown	Sept 9 – Oct 28	~ 16/week
Train the Organization	November	~ 24 hours
Update End-User Queries	November - December	Varies
Assist with rollout	Dec - Jan	Varies

Note: 2014 budget documentation can be found in U:\Public\Budget Info\2014 Budget

Overview For Budget Input

Planning Must Be Done For The Following:
➢ Gross Payroll (Dollars)
➢ Staffing Level (Headcount) – Coordinate with IBP-Business Services and Workforce Planning
➢ Other – Than – Labor (OTL)
➢ Activity Input Planning (Hours to Cost Centers, WBSs and Internal Orders)
Versions
Annual Budget: ➢ 2014 Budget detail planning will be **input** in Version 20 ➢ 2014 Final Closed detail budget will be in Version 12 unless otherwise noted

Calendar of Events

The 2014 Forecast Schedule

Activity	Completion Date
➢ **SAP 2014 V20 Opens**	7/29/2013
➢ **Complete Headcount & Gross Payroll**	8/30/2013
➢ **All Revenues & Expenses updated to calculate deferrals**	9/6/2013
➢ **Lock SAP V20 @ 5 p.m.**	9/13/2013
➢ **IBP/Gen Accounting process 2014 Budget V13**	9/16 – 9/20/2013
➢ **Business Units to begin validation of results**	9/20/2013

Dates for the final budget will be announced after the forecast is completed.

The 2014 Budget Schedule

Activity: Business Units enter 2014 Detail Budgets	Completion Date
➢ **Gross Payroll Input Complete**	TBD
➢ **Headcount Input Complete**	TBD
➢ **HR Benefits Complete**	TBD
➢ **Revenues/Expenses Impacting Deferrals & Amortizations (Including Inter-Company Transactions)**	TBD
➢ **Transmission Revenues & Expenses**	TBD
➢ **Inter-company Transactions Input Complete**	TBD
➢ **Lockdown of SAP system**	TBD

THESE DATES ARE SUBJECT TO CHANGE

Throughout the budget cycle you should expect to receive communications as needed to ensure the schedule is met. The purpose of these communications will be to help individuals manage budgeting activities, ensure mid-process completion goals are met, and address any issues that arise during the budget entry period.

CHAPTER 2: LABOR

Straight Time Payroll

Straight time payroll for the 2014 Budget will be developed and input by the Business Units. The budget is based on projected staffing levels and estimated employee salaries based on a regular weekly schedule of 40 hours per week per full-time employee
Adjustments should be made for changes in payroll due to attrition, retirements, promotions, demotions, and all salary adjustments including general wage rate increases. **Annual wage rate increases need to be applied by the Business Units, based on the appropriate rate change and timing.** The assumed wage rate for non-bargaining employees is 3.0%. The non-bargaining WRI should be assumed to be effective September 1, 2014. For bargaining unit employees, the bargaining unit WRI is based on the terms of each union contract.

The monthly spread of straight time labor should be based on the number of pay weeks in each month according to the Payroll Calendar. Distribution key(s) for the monthly distribution of payroll are noted below for bi-weekly payroll and in the Reference Material Section for the weekly payroll. Keep in mind, the distribution keys are only used to spread the monthly data and **do not** increase the yearly or monthly totals for the wage rate increases. The budget preparer needs to calculate the annual payroll and inflate it for any expected WRI, then use the appropriate distribution key to spread the payroll. **Payroll must be spread by month, not summed and input into one month.**

The appropriate general ledger accounts/cost elements for Straight Time Labor:

Straight Time Payroll

520010	Payroll - Straight Time - Bargaining
520050	Payroll - Straight Time - Non-Bargaining
520051	Payroll - Straight Time - Temporary Help
520062	Payroll - Straight Time Coop Students
520063	Payroll - Straight Time-Part Time-Non-Barg
520064	Payroll - Straight Time-Part Time-Bargaining

NOTE: If a Business Unit(s) has a question about developing its straight time payroll estimates or the input of the dollars into SAP (including the appropriate spreads and wage rate increases), please contact Corporate Budgets and Forecasts before the Gross Payroll entry deadline. (See Key Contacts page 27)

Payroll Calendar Information:

2014 Bi-Weekly payroll

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Weeks	4	4	6	4	4	4	4	6	4	4	4	4	52
Hours	160	160	240	160	160	160	160	240	160	160	160	160	2080

Distribution Keys **P14S and P14B** both use this spread pattern. The P13B Distribution Key assumes a 3% March wage increase, while **P14S** assumes a 3% wage increase in September.

2014 Weekly payroll

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec	Total
Weeks	4	4	5	4	5	4	4	5	4	4	5	4	52
Hours	160	160	200	160	200	160	160	200	160	160	200	160	2080

For weekly payroll, refer to the list of Distribution Keys in the Reference Material Section (Chapter 7) for the distribution key that spreads payroll based on the effective month of the WRI. If additional distribution keys are needed, contact Corporate Budgets and Forecasts.

Overtime Payroll

Costs associated in a given pay week for work exceeding 40 hours. The addition of overtime dollars to the budget should be planned and approved accordingly. Planning for all overtime will be completed by the business units using the appropriate cost elements:

520110 Payroll - Overtime Bargaining
520150 Payroll - Overtime Non Bargaining
520151 Payroll - Overtime Temporary Help
520162 Payroll - Overtime Co-Op Student
520163 Payroll - Overtime Part Time Non Barg
520164 Payroll - Overtime Part Time Bargaining

Payroll Overheads

Payroll Overheads – Employee Benefits, Incentive Comp and Payroll Taxes will be applied as an overhead during the closing process. The rates will be determined by General Accounting and input into the SAP costing sheets after final payroll is determined and all gross benefit costs (medical, dental, prescription drug etc.) are input into the HR benefit cost centers.

Employee Benefits – Benefit costs *will be developed by Human Resources/Corp Budgets & Forecasts* and input into the Special Purpose Ledger (SPL) in HR benefit cost centers using the appropriate primary cost elements. Pension and OPEB costs are not included in the Employee Benefits overhead calculation but are applied to capital work as specific capital overheads.

The secondary cost element 850070 – Payroll Overhead Benefits – Straight Time will be used to apply the Benefit overhead on straight time payroll during the budget closing process.

Payroll Taxes - *will be budgeted by Corporate Budgets and Forecasts* and input into the SPL in Special Tax cost centers.

The secondary cost element 850080 – Payroll Overhead – Taxes will be used to apply the Payroll Tax overhead on straight time and overtime payroll during the closing process.

Incentive Comp - *will be budgeted by Human Resources/Corp Budgets and Forecasts* and input into the SPL in Special Incentive Comp cost centers.

The secondary cost element 850090 – Incentive Comp will be used to apply the Incentive Comp overhead on straight time and overtime payroll during the closing process.

Payroll Related Items

Other payroll related general ledger accounts/cost elements:

520019 Payroll Retention Bonuses – Budgeted by the Business Unit granting the bonus
520165 Payroll Accrual (Budgeted only by General Accounting)
520250 Payroll Bonuses - Represents annual bonuses and other bonuses awarded throughout the year for special circumstances and are the responsibility of the Business Units
520260 Payroll Additional Comp – MGRK (Budgeted by Business Units where appropriate)
520300 Payroll Restricted Stock (Budgeted only by HR/Corporate Budgets and Forecasts)
520400 Payroll Severance – (Budget only by HR/Corporate Budgets and Forecasts)
520500 Payroll Adjustments to Gross - Examples include retro pay, grievance settlements, remote reporting costs, and relocation expenses not covered by HR (See Relocation Policy found on the Services & Support section of the FirstPlace Portal).

SAP INPUT – TRANSACTIONS OVERVIEW for GROSS PAYROLL
Set Planner Profile => Transaction KP04
Profile = FE-CO01
Planning Input => Transaction KP06
Layout = CC Primary No Excel or CC Prime – Y4

Note: Under no circumstance, should any of the payroll-related costs listed, including straight time, overtime, or bonuses be budgeted directly in the SPL via Transaction GP12N. Transaction KP06 should be used.

Staffing

Staffing levels (Headcount) **must be input by month**, by individual Cost Center, using Statistical Key Figures (SKFs) – transaction KP46. Budget all full-time, part-time, and temporary FE employees on SAP Payroll. **New employees should be budgeted in the month in which they will start.** Do not include contractor/non-FE employees and do not assume all hires begin the month of January. The following SKFs should be used:

	Bargaining	Non-Bargaining
Full-Time	EMPFTB	EMPFTN
Part-Time	EMPPTB	EMPPTN
Temporary	EMPTPB	EMPTPN
Student Intern	EMPSIB	EMPSIN

SAP INPUT – TRANSACTIONS OVERVIEW for STATISTICAL KEY FIGURES
Set Planner Profile => Transaction KP04
Profile = FE-CO01
Planning Input => Transaction KP46
Layout = CCTR STAT Key Fig PL or SKF – Y4

Budget Tip: After input of staffing levels and payroll dollars is complete, check that the monthly payroll totals are consistent with the monthly headcount projections.

Activity Input Planning (Hours)

Payroll costs can be moved from the employee or responsible cost centers to a target or receiving cost collector (Cost Center, Order or WBS element) by planning productive hours by activity type. The activity price associated with each cost center/activity type combination is calculated and input by Corporate Budgets and Forecasts. These activity prices are then used to produce the standard labor activity allocations.

Unproductive Time – Planning for unproductive time (i.e. sick time, safety meetings, union business, etc.) is not required. These costs remain in the responsible cost center and the unproductive hours and associated costs are incorporated in the calculation of the activity prices.

SAP INPUT – TRANSACTIONS OVERVIEW for ACTIVITY INPUT PLANNING (HOURS)

Set Planner Profile => Transaction KP04
Profile for Hrs charged to Cost Centers = FE-CO01
Profile for Hrs charged to Int. Order = FE-CO01
Profile for Hrs charged to WBS Elem = TD-PS01 or GEN-FRMF or GEN-FRMN

Planning Input =>
Cost Centers => Transaction KP06
Layout = CC Act Inp No Excel or CC – Act – Y4
Int. Orders => Transaction KPF6
Layout = OR Act Inp No Excel or OR – Act- Y4
WBS Elem => Transaction CJR2
Layout = Act Input or WBS – Act – Y4

CHAPTER 3: OTHER THAN LABOR (OTL)

All input into the SAP system for non-labor items is entered in Special Purpose Ledger Z9 using transaction GP12N – Change Plan Data - Special Purpose Ledger.

All transactions for non-labor items must contain:

Responsible Cost Center
Cost Element
Target Cost Collector – Cost Center, Order, Network or WBS element
Target Cost Collector Type – (KS, OR, PR)
Cost Type (Capital, O&M, Other)

Responsible Cost Center for Other-Than-Labor is defined as the Cost Center with budget responsibility for the expenditure.

All OTL input into the Special Ledger must be entered as company SC00.

Cost Types are defined as follows:

Type 1 Capital - Capital is planned to WBS Elements. WBS Elements are defined as Cost Type 1 if they settle to:

107XXX Construction Work In Progress
108XXX Retirement Work In Progress
Capitalized Nuclear Fuel Accounts
CWIP and RWIP for Non-Utility assets

Type 2 O&M (Income Statement Accounts)

Type 2 is any cost that settles to a Cost Center and becomes part of the Income Statement (predominately O&M but includes revenues, interest income, depreciation etc.)

Type 3 Other

Type 3 charges are any costs that settle to Balance Sheet accounts and are not considered Capital.

SAP INPUT – TRANSACTIONS OVERVIEW FOR OTL
Set Planner Profile => Transaction GLPLSET
Profile = ZZSPL902
Planning Input => Transaction GP12N
Layout = ZZSPL90 or ZZSPL90 – Y4

Guidelines for General Business Items:

Office Supplies – Cost Element 540100
Stationary type items purchased through Staples or similar vendor, e.g., annual planners and calendars, etc. The budget should be at the department/plant level rather than the cost center level to maintain consistency and control within the business unit.

Telecommunications Equipment and Service – Cost Element 590000
Costs associated with Company approved/provided cellular telephone equipment and associated monthly cellular charges are to be budgeted by cellular user's business unit.

- Basic cellular voice/text service - $50 monthly per telephone.
- Smartphone (iPhone) - $100 monthly per telephone.
- Cellular broadband data service (laptop and MiFi's/HotSpot) - $55 monthly per device.

Business Units should refer to the Computer Peripherals Price List (page 11) to budget for costs associated with purchase of the cellular equipment.

Copies/Multi-functional devices (MFD), Printers, Faxes
Copier/MFD and printer equipment along with maintenance and supplies for general office use are budgeted by IT. Plotter purchase/lease, specialty copiers or printers, fax machines, and associated service/supply costs are to be budgeted by the responsible Business Unit. For special projects, short-term needs, and plant outages the cost for copy, fax, and print devices are to be budgeted by the responsible Business Unit. Contact IT to determine if existing devices may be redeployed for short term needs.
Budget printer equipment to G/L 580020, supplies to 560200, and maintenance to 550300.
Budget copier equipment to G/L 570052, supplies and maintenance to 560200.
Budget fax equipment and supplies to G/L 560200, maintenance to 550300.

Employee Expenses – Cost Element 540000
Miscellaneous expenses as a result of conducting company business not captured in other cost elements and reimbursed through an employee expense report.

Employee Meals – Cost Element 540010
Expensed meals as a result of company business.

Emergency Employee Expense / No Meals – Cost Element 540015
Miscellaneous expenses that were incurred unexpectedly (call-outs, storms, and outages).

Travel Expenses – Cost Element 540101
Expenses incurred while traveling on company business that are not reimbursed through employee expense reports. Each business unit should budget for use of the corporate jet by their employees at the rate of $220 per "one way trip". Example: For one person flying from Akron to Morristown, $220 is charged to the employee's responsible cost center. Persons budgeting for Executive travel will be provided more detailed information separately from these guidelines.

Per Diem – Cost Element 540102
Fixed rate for change in work location, outages, etc. Often used in lieu of meals and possibly other related employee expenses.

Travel Expenses – Corp Jet – Cost Element 540106
Costs associated with use of corporate jet. This cost element is used exclusively by the Flight Operations Group.

Employee Expense – Training – Cost Element 540020
External seminar fees and associated external training expenses.

Training Student Expenses – Cost Element 540103
Student training fees for internal courses coordinated by Human Resources.

Postage – Cost Element 650100
All non-customer mailings/billings, including large packages (UPS, FedEx, Overnight Express, etc) should be budgeted by each Business Unit. Postage for customer related mailings and billings should be budgeted by the Customer Service bill production cost centers.

Other Items:

Application Software Maintenance – Business application software maintenance will be budgeted by IT Business Unit Support. Portfolio Managers will be contacting your department to coordinate budget information and ensure that all maintenance fees are captured.

Banked Vacation – The payout of banked vacation ***should not be budgeted*** by the individual cost centers. It is budgeted by Human Resources/Corp Budgets/Forecasts.

Claims (Payable and Receivable) – The ED Operating Companies should budget for (payable) claims and lawsuits related to distribution facilities (including personal injury, property damage, and vegetation management claims), fleet vehicle accidents, and environmental injuries (such as asbestos) for historical ownership of generating plants, as well as the legal fees and other administrative costs to defend against such claims and lawsuits. The ED Operating Companies should also budget for damages caused to their respective distribution facilities by outside parties; applying offsets by taking into consideration historical recovery amounts achieved through (receivable) claims activities. Generating Plants should budget for anticipated (payable) claims and lawsuits related to their facilities, as well as the legal fees and other administrative costs to defend against such claims and lawsuits.

Company Facilities – Real Estate and Facilities will budget for the maintenance and service contracts for Corporate, FENOC and Fossil. Energy Delivery will budget for all Utility Company facilities. The WBS structure will be utilized for both budgeting and tracking of O&M spend. Budgets will be established using a WBS and WBS Element / Service Categories:

- Landscaping
- Janitorial
- Building Maintenance
- Waste Removal
- Paving repairs
- Elevators
- HVAC
- Roof repairs
- Electrical
- Mechanical Equipment
- Fire Protection
- Construction
- Fences
- Plumbing
- Painting
- Pest Control
- Utilities
- Snow Removal

- Costs will be segregated by line of business (Corporate, FENOC, Fossil, and ED Operating Company)
- Monthly reporting of actuals will include the WBS, the Service Category and Building Cost Center
- This will allow for a direct comparison of Budget to actual spend enabling a monthly view of actuals versus budget.

Real Estate will budget for all building and land leases.

Corporate membership dues and fees, contributions and donations – It is the Company's policy to enter into and maintain Corporate memberships in organizations deemed necessary to maintain

professional expertise in various aspects of the Company's operations and to establish and maintain relationships with selected organizations with whom we share common interests.
Corporate memberships will be budgeted and processed through the Contributions Department. The company should not pay dues for an employee's individual membership unless the membership is held at the Company's specific request. When this is the case, the dues and any fees or assessments associated with membership should be budgeted in the employee's administrative cost center. Contributions will also be budgeted through the Contributions Department, working with Operating Company management and the Corporate Affairs staff.

Desktop Computer Hardware and Software – Standard PC workstations and laptops are budgeted in IT Client Support based on a fixed replacement cycle (5 years for desktops, 3 years for laptops). **Peripheral equipment is not budgeted in IT.** All peripheral equipment requires director approval, will be ordered by the business unit (not IT) using a specific web site, **and should be budgeted as a purchase in the requesting business unit cost center**. Listed below are some commonly requested peripherals with pricing where applicable.

Computer Peripherals Price List:

Display Options	Description	Vendor / Model	Approximate Cost
For Laptops	Monitors not provided for laptops		n/a
For Desktops	17 inch CRT provided for desktops upon failure of previous unit	See HP or SHI catalog on portal for options.	
Cellular	**Description**	**Vendor / Model**	**Approximate Cost**
Cellular voice/text	Basic cellular handset and standard accessories.	First Communications	$30
iPhone	iPhone and standard accessories.	AT&T, Sprint, Verizon Wireless	$150
Data – MiFi/Hot Spot	Data device.	AT&T, Sprint, Verizon Wireless	$80 - $130
Laptop Options	**Description**	**Vendor / Model**	**Approximate Cost**
Port Replicator for nc8440p/8540p/8460/8470	Part # A7E34AA#ABA	HP	$130
Plotters	**Description**	**Vendor / Model**	**Approximate Cost**
Standard HP Plotter Purchase	Wide Format plotter/printer purchase and install	HP	$6,800
Standard HP Plotter Service	Annual service for HP Plotter	Print Service Provider	$1,654

Educational Assistance – Human Resources/Corp Budgets/Forecasts will budget for these expenses.

Environmental Fees – Permit and environmental reporting fees should be budgeted by each location. The Environmental Dept. will budget for all software maintenance fees associated with the ESC CEM data acquisition systems. The Environmental Department will also budget for all stack and CEM RATA testing including labor, materials and outside test contractors. Questions should be directed to **Brittany Cannato 879-6442.**

EPRI – Business Units should budget for EPRI expenses based on approved programs as well as approved participation in Tailored Collaboration Projects, Co Funding Projects, or Billable Service Agreements (Supplemental Agreements that are in addition to membership selections). Item numbers for EPRI subscriptions will be available from FE Technologies . Subscription payments should be budgeted monthly. Business Units who budget for EPRI should contact **Stephen B. Briggs 825-3870**, for further information.

Fuel – Nuclear: The nuclear fuel expense budget is developed and entered by the Nuclear Fuels group based on generation plans provided by each nuclear unit. Auxiliary boiler and diesel generator fuel is budgeted by each nuclear site and entered by the Nuclear Generation Business Services. Capital nuclear fuel purchases will be budgeted by the Nuclear Fuels group, to appropriate WBS elements.
Fossil: Coal, Oil (light-off and peaking), natural gas, SO2 allowances, NOX allowances, and reagent

requirements will be modeled by the FES Planning & Analysis Group and budgeted by the Fuel Supply Dept., using the plant/unit specific FERC cost centers.

Insurance – Property and liability insurance will be budgeted by Risk Management.

Internal Use of Electricity – The costs of electricity for buildings and power plants owned by FE legal entities within the Competitive Services Unit and Corporate Support Unit, for both generation and non-generation components will be budgeted by **William Shonk (825-5472)** of General Accounting Services in coordination with Customer Service, Retail Tariff Analysis & Forecasting and Facilities Management.

Inter-company Building Rent Revenue/Expense – The inter-company revenue and expense for building rent invoiced between companies will be budgeted by **Richard Snyder (500-6807)** of General Accounting Services and will be based upon building related operation and maintenance costs budgeted by others.

Materials and Equipment – Material costs for direct purchases and stores issues are budgeted directly in the cost center, order or WBS element along with the responsible cost center. An M&S overhead will be applied to stores issues. The Controller's Group will enter the rates into the costing sheets and the system will generate the M&S overheads as part of the budget closing process.

Professional Contractors & Outside Services – Contracted work from professional and outside services vendors should be accounted for using the categories and cost elements established by Business Unit. Please refer to the tables in Chapter 7 for further details.

Revenues – Budgeted revenues must be entered as **negative** numbers.

Sales Tax – Business Units should include sales taxes incurred as part of the purchase price of taxable items in their cost centers.

Medical Surveillance Testing – Occupational Health -The outside vendor costs for employees participating in the FirstEnergy Medical Surveillance Program (Regulatory required) should be budgeted in the individual employee's responsible Cost Center. Each Plant and Operating Company should account for these costs (i.e., regulatory required respirator fitness exams, hearing tests, asbestos and lead physicals, etc.). The Industrial Relations-Health & Safety section will provide specific cost information related to this activity, contact **Timothy Walter 825-1706 or Chuck Fabo 825-5162.**

Drug & Alcohol Testing Program – CDL/DOT, Maritime, Safety Sensitive, Ohio State Project Work, New Hires- The outside vendor costs for employees participating in FirstEnergy's Drug & Alcohol Testing Program (Company and Regulatory required) should be budgeted in the individual employee's responsible Cost Center. Each Plant and Operating Company should account for these costs in 2014. The Industrial Relations-Health & Safety section will provide specific cost information related to this activity, contact **Timothy Walter 825-1706 or Chuck Fabo 825-5162.**

Industrial Hygiene (IH) Assessments – The outside vendor costs associated with OSHA required routine IH monitoring, including associated laboratory analyses and processing costs, should be budgeted in the individual employee's responsible cost center. Routine monitoring (OSHA required) includes periodic assessment of the following hazards: Noise, Asbestos, Inorganic-arsenic, Lead, Personal Protective Equipment, Confined Space Entry, etc. The Industrial Relations–Health & Safety section will continue to support and budget for special, complex or unique IH assessment needs. Specific cost information related to this budgeting activity will be provided by the Industrial Relations-Health & Safety section, contact **Timothy Walter 825-1706 or Martin Duffy 825-3814.**

Satellite Airtime – The infrastructure cost to provide the service will be paid by IT Network Services. The usage is not an IT cost and should, therefore, be budgeted by the business units at these rates:

BTV broadcasts $800 /hour (Bandwidth 3.0Mb/hr)

Severance – Each Executive Council member is contacted by HR to determine the appropriate level of severance to be budgeted. Cost of severance payments, as determined by HR, will be entered into the SAP system by HR/Corp Budgets/Forecasts.

Supply Chain/Inventory Items – Inventory Adjustments - Each plant and Operating Company should budget for its own storeroom's inventory adjustments. Assets No Longer Used or Useful – Obsolete Inventory - Each location should budget for its own obsolete inventory write-offs. With market value of these items being unknown, it is recommended that Business Units not budget for proceeds from obsolete inventory sales. Assets Other Than Inventory - Investment recovery proceeds from the sale of items will be given to the Business Unit that provided the items. We will use the accounting the Business Unit provides.

Training – Business unit cost centers should budget for on-site classes that support company-wide, employee, or department-specific programs. **The Learning and Development Department (L&D) will budget for the New Supervisor/Manager program. However, the business unit cost centers should budget for associated travel and lodging expense.** Questions should be addressed to **Jacqueline Roth 825-7890.**

The Information Technology Dept (IT) will budget for on-site classes that support company-wide software applications. Business unit cost centers should budget for on-site classes that support department-specific software applications.

Training – External – The cost of external training and seminars, as well as the travel and lodging expenses will be budgeted in the cost center requesting the training.

Transportation – Energy Delivery Transportation costs will be manually planned to appropriate cost collectors using the cost element 545099 – Fleet usage manual plan. The responsible cost center used on the SPL is the appropriate Operating Company transportation contra cost center.

COMPANY	CONTRA COST CENTER	DESCRIPTION
Toledo Edison	416001	Transportation Costs Undist-TE-Wstrn Reg
CEI	426001	Transportation Costs Undist-CE-Nrth Reg
Ohio Edison	406001	Transportation Costs Undist-OE-Cntrl Reg
Ohio Edison	406005	Transportation Costs Undist-OE-Sthrn Reg
Ohio Edison	406003	Transportation Costs Undist-OE-Estrn Reg
Penn Power	436001	Transportation Costs Undist-PP-Estrn Reg
Penelec	456001	Transportation Costs Undist-PN-W PA Reg
Met Ed	446001	Transportation Costs Undist-ME-E PA Reg
JCP&L	466003	Transportation Costs Undist-JC-Nrth Reg
JCP&L	466001	Transportation Costs Undist-JC-Cntrl Reg
West Penn Power	492001	Transportation Costs Undistrib- WP01
Mon Power	470201	Transportation Costs Undistrib - MP01
Potomac Edison	483001	Transportation Costs Undistrib - PE10

The Operating Companies must also plan a credit to the contra cost center in the amount planned out to the cost collectors using the same Responsible Cost Center. The contra cost center should be used as the target cost center for these credits.

Vehicle Leases & Licenses –
Vehicle lease payments should be budgeted, using G/L account 570050 for all Operating Leases and 570075 for all Capital Leases, for the following:

- Fleet Services cost center for Operating Company vehicles, (it is no longer necessary to budget by each department in the Operating Company using the vehicle).
- Each fossil generation plant, each nuclear generation plant, environmental, generation technical services.
- Each non-Operating Company or non-plant department using a vehicle. This would include (but is not limited to): IT, Corporate Transportation, Workforce Development, Administrative Services, T&D Technical Services.

Vehicle licenses should be budgeted, using G/L account 650300, for the following:

- Fleet Services cost center for Operating Company vehicles.
- Each fossil generation plant, each nuclear generation plant, environmental, generation technical services.
- Each non-Operating Company or non-plant department using a vehicle. This would include (but is not limited to): IT, Corporate Transportation, Workforce Development, Administrative Services, T&D Technical Services.

All requests for vehicles and/or power operated equipment should be directed to the Fleet Manager (see below) responsible for the area where the vehicle and/or equipment will be assigned. The Fleet Manager will work with Corporate Fleet Services directly to place the order, etc. Any questions related to this matter should be directed to **Lisa Pfeifer 824-5090.**

Company	Fleet Services Manager	Internal Phone	External Phone
CEI	Bryan Komlos	824-5060	216-295-5060
Toledo Edison	Jeff Burgoon	883-5938	419-249-5938
Ohio Edison/Penn Power	Robert Pyles	835-4099	330-436-4099
West Penn Power	Mike Geitner	365-2020	724-743-2020
Penelec	Wally Cunningham	430-8803	814-868-8803
Met Ed	Frank Cummins	500-6573	610-921-6573
Mon Power	Forrest Miller	324-1211	304-284-1211
Potomac Edison	Jasan Hileman	300-5227	301-582-5227
JCP&L	Nick Dello Russo	210-2237	973-989-2237

Personal Computer Hardware Items that require direct funding by the Business Units:

Unique, non-standard PC configurations. IT budgets each year for standard notebook and desktop models and configurations. At the time IT approaches a client group to plan for the retirement / replacement of their existing computers, the client group will need to provide the funds to cover any cost above the standard model cost. Funding by the client will be required for special features such as:

- RAM (memory) above the standard configuration
- Higher CPU speeds or multiple CPU's
- Tower model
- Floppy drive (no longer provided on new PCs)
- Video graphic cards

- Extra network interface cards
- Optical or wireless mice or special trackball configurations
- Ergonometric keyboards
- Larger internal or external storage drives or memory sticks
- Port replicators or docking stations
- Second batteries for notebook PCs
- Glare shields
- DC power converters or adapters
- Monitors for notebooks (If you presently have one with your notebook, when it fails, it will not be replaced without business unit funding.)
- Local printer (all printer requests must be forwarded to **David A. Zeigler** for review).

Process related PCs. IT budgets each year for rollover of **20%** of the office desktop PCs and **33%** of the office notebook PCs. PCs that are not typically used by employees, but rather dedicated to a process are not funded out of the PC capital budget. Funding must be provided either within a capital project when these systems are upgraded, or by the business unit. Examples of process PCs include:

- AFSO and MRMS (TPP)
- EMS Consoles
- GMS Consoles
- HVAC controls
- Plant control systems
- Badge readers
- Field equipment testing or data logging PCs
- Special printer, scanner or plotter interfaces
- Cache PCs (pseudo servers)

Off-cycle (premature) replacement PCs. As mentioned earlier, IT budgets each year for rollover of 20% of the office desktop PCs and 33% of the office notebook PCs. The scheduling of replacements is determined by the local Desktop Support team. Should any department require a notebook PC to be replaced sooner than every 3 years, or a desktop model to be replaced sooner than every 5 years, the client group must fund the complete cost of the replacement.

Off-cycle upgrade of a desktop unit to a notebook unit. If an employee, because of their job responsibilities, requires switching from a desktop PC to a notebook PC, the full cost of the new notebook PC must be borne by the business unit if their desktop is not scheduled to be replaced. The exception to this rule is if the business unit still has un-deployed notebook PCs in its annual replacement allotment, the business unit leadership may elect to redirect a yet-to-be-deployed notebook from its pool to the employee in need, at the sacrifice of another employee within the business unit. That impacted employee would then be given the notebook recipient's existing desktop PC.

On-cycle upgrade of a desktop unit to a notebook unit. If an employee, because of their job responsibilities, requires switching from a desktop PC to a notebook PC, and the timing of this need coincides with our replacement schedule, IT will cover the higher cost of the notebook PC. New or replacement notebooks will require director level review and approval. There must be a valid business case for using a notebook model.

Second PCs. If an employee requires more than one PC to perform their job, the full cost of the additional PCs must be borne by the business unit. This includes instances where a hot-standby PC must be provided for a critical function. The exceptions to this rule are console-based PCs, such as those in plant control rooms or regional dispatch centers where 2-3 PCs and/or monitors are part of the console and required for the operator to perform their work. This second PC will be an asset managed and maintained by IT, following the same standards and practices used for IT-funded PCs.

<u>Moves, Adds, Changes (MACs) of Employee Services and Devices at Company Facilities –</u> For all locations other than Shared Services' workspace in Akron General Office and the Reading General Office - Business Units will be responsible for budgeting for their planned moves, adds and changes described below:

- Non-computer equipment, such as telephone sets, headsets, speakerphones etc.
- Install and terminate voice cabling to workstations.
- Creation of the workstations in the telephone system database.
- Cross-connected and install telephone instruments.
- Move telephones to existing or new jack locations.
- Install, terminate, and test data cabling to the workstations.
- Activate data jacks by patching through to data switches.
- Install, terminate, and test inside fiber optic cabling.
- Install and terminate coax cabling for applications such as Satellite for IDL.

This does not include maintenance or repair responsibilities for these items. Normally the moves, adds, and changes are considered an O&M cost, unless they are associated with a major project.

The usual way to schedule moves, adds and changes is to contact your local facilities management team. This team will contact IT Field Operations to arrange for the approved vendors to make your requested changes. MACs that do not require Facilities involvement can be requested by calling the IT Service Desk. Please adjust your 2014 budget to include your facilities plan.

CHAPTER 4: CAPITAL MANAGEMENT PROCESS

FE's capital investments are integral in helping the company achieve operational excellence and financial success. The capital expenditures, are necessary to ensure the reliable generation and distribution of electricity, and compliance with regulatory requirements.

The Capital Planning & Management Process is a formalized process that provides the platform for capital discussions and allocation decisions at all levels of the organization. The process helps senior management to effectively understand competing uses for FE's cash, funding requirements for capital investments, and to allocate capital dollars across various business units (ED, FENOC, Fossil, Corporate). Ref. Capital Planning & Management Corporate Policy CP-TPR-6101 and FE 5-year Capital Portfolio Development and Capital Management Procedure (FirstPlace Portal/About FirstEnergy/Policies and Practices/Overview/Capital Management Procedure.pdf)

Capital Categories:

Mandatory - Non-discretionary investment required by law, regulatory order, or duty to serve customers (e.g. new business). Other required investment to meet externally driven regulatory commitment.

Maintain - Discretionary investment to support and sustain existing infrastructure at existing performance levels. Specific operational performance and financial tracking support these projects (e.g. SAIDI, CAIDI, EFOR).

Improve - Discretionary investment to improve existing infrastructure or performnace levels beyond existing business plan key performance metric commitments. Improvement in specific operational performance and financial benchmark targets support these projects (e.g. SAIDI, EFOR, ROI).

Value - Discretionary, non-recurring investment for a defined initiative which improves or expands existing infrastructure or creates new business opportunities and drives improved economic value.

Capital questions contact:

Business Area	Business Area Contact	Capital Support
Corporate Services - IT	Debbie Luttner (350.6934)	Megan Gallagher (825.5821) Scott McBride (825.4888)
	Dave McGaha (850.2167)	
Corporate Services - Facilities	Bob Grosjean (825.6393)	
	Tom Yanks (825. 5926)	
Corporate Services - Other	Business Area Management	
FE Utilities/Transmission	Mark Myers (825.7961)	
	Marcus Geise (825.2542)	
Fossil Generation	Joe Walko (350.5722)	
	Denise Bracken (850.7237)	
FENOC	Jay Morris (879.5425)	
	Don Jacobson (879.7605)	
FES - Other	Ollie Pannell (850.6868)	
	Brandon Fedor (850.7226)	

Capital Projects – Only budget capital projects to the level of spending identified in Executive Council guidance

Work Breakdown Structures (WBS) - Labor is budgeted through Activity Input Planning using transaction CJR2. Loaded labor costs, which include overheads, are moved from the employee or sending cost center to a WBS element by planning productive hours by activity type. Instructions for Activity Input Planning are located in Chapter 2 - Labor. All 'Other than Labor' costs are input into the SPL using transaction GP12N and must include the cost element and the appropriate responsible cost center. Instructions for input are found in Chapter 3 – OTL.

If new WBSs are created, all master data fields (i.e., costing sheets, project type, interest profiles, settlement rules, etc.) must be entered into SAP. **(See Key Contact appendix, page 26, for names to set up the WBS Master Data.) In all cases, it is critical that the WBS and WBS element start and finish dates be accurate and the WBS should be established at the Company which will own the assets. Departments which complete work for other Companies should cross charge the other Company WBS. Planning must never be entered in months beyond the finish date.** These dates are used by Property Accounting Services to compute and input AFUDC and depreciation and in reporting, including rate cases. All WBSs with settlement rules to asset accounts (CWIP, RWIP & OWIP) require an AFUDC element regardless if the project would qualify for AFUDC.

The status of WBSs must be TECO (Technically Complete), when the project is ready for service. The TECO date is passed to PowerPlant and the project is placed in-service. If a project is suspended or ceases construction the WBS elements should be locked and the status of the project is changed to "suspended" in PowerPlant. This will shut off the AFUDC calculation. If a project is cancelled existing charges should be transferred to expense, the AFUDC should be reversed and once the charges have been removed from the WBS, the WBS should be 'business closed". **It is important to update the status to TECO on a timely basis since it directly reflects the calculation of AFUDC and the beginning of depreciation in PowerPlant.**

Construction Indirects (Supervisory, Engineering, Administrative and General Overheads) – Capital costs should be direct charged to the related WBS whenever possible. However, in those cases where certain costs have a proven relationship to construction, an assessment or allocation will be made from predefined cost centers to Operating Company construction indirect cost centers (Supervision, Engineering, and A&G). An example of this would be supervision of an engineering group that supports capital projects overall. A portion of those supervision costs will be allocated to capital using the prescribed process. Rates will be calculated by General Accounting Services for each Operating Company and overhead category and will be applied on the labor and contractor portion of the budgeted WBS elements.

PowerPlant Property Unit Catalog – The PowerPlant Property Unit Catalog should be used to determine what items or activities are capital. Assistance in using the Property Unit Catalog or questionable items should be directed to **Tim Clyde (825-5863)**, Property Accounting Services, prior to inclusion of an item in the budget as capital.

Small Tools and Equipment - Only small tools and equipment greater than $1,000 should be capitalized.

Corporate Facilities will budget for all facility-related Mandatory and Maintain capital project work across FirstEnergy. Each Business Unit will budget for any Value Added or Improve facility related capital work. If there are questions on definition, please refer to the Capital Definitions section.

Vehicles/Power Operated Equipment
When acquiring the equipment identified below, the acquisition should be coordinated with the Corporate Fleet Services Department. The Corporate Fleet Services Department will determine with Treasury whether to purchase or lease the equipment. If the decision is to purchase the equipment, Corporate Fleet Services will purchase the equipment and charge the appropriate capital WBS. The equipment will also be given a vehicle number and tracked in the M5 Fleet System.

All requests for vehicles and/or power operated equipment should be directed to the Fleet Manager (see below) responsible for the area where the vehicle and/or equipment will be assigned. The Fleet Manager will work with Corporate Fleet Services directly to place the order, etc. Any questions related to this matter should be directed to **Lisa Pfeifer 824-4090.**

Company	Fleet Services Manager	Internal Phone	External Phone
CEI	Bryan Komlos	824-5060	216-295-5060
Toledo Edison	Jeff Burgoon	883-5938	419-249-5938
Ohio Edison/Penn Power	Robert Pyles	835-4099	330-436-4099
West Penn Power	Mike Geitner	365-2020	724-743-2020
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Met Ed	Frank Cummins	500-6573	610-921-6573
Mon Power	Forrest Miller	324-1211	304-284-1211
Potomac Edison	Jasan Hileman	300-5227	301-582-5227
JCP&L	Nick Dello Russo	210-2237	973-989-2237

Asset Class	Vehicle Type
1	Light Duty - primarily downsize pickups, mini vans, passenger cars & units impacted by EPAct
2	Medium Duty - includes full size pickups, vans, substation vehicles, small stake body trucks, etc
3	Heavy Duty - includes heavy trucks other than aerial units, digger derricks or crane trucks
4	Aerial Trucks - includes all manlift capabilities regardless of size
5	Digger Derrick Trucks - includes all digger derricks
6	Crane Trucks - includes all trucks with cranes mounted on them and licensed. Off road cranes are included in construction equipment
7	Trailers - includes all trailers regardless of size
8	Construction Equipment - includes backhoes, loaders, excavators, off-road cranes, dozers, etc
9	Forklifts, Mowers, Misc - includes forklifts, riding sweepers, scrubbers, snow removal equipment, mowers, ATV's & other.

Office Furniture – The Real Estate and Facilities Department manages and budgets all capital expenditures for furniture as well as maintains an inventory of existing furniture items. The Facilities Section has developed the Workspace Guidelines Policy and receives substantial discounted pricing on all furniture used by the Company.

All requests for furniture should be directed to **Kathy Tatman, Supervisor, Asset Planning** through an e-mail notification. Please base your request on budgeted new hire positions and/or replacement requirements for worn, damaged or obsolete furniture. Any purchases of furniture made outside of this arrangement will not be approved.

Software Costs - The following guidelines should be used for capitalizing computer software costs:

New Computer Software Costs:

- designed as a complete system
- has a life greater than 1 year
- capitalized cost is greater than **$5,000**

Preliminary study costs, data conversions, and training are expensed when installing computer software.

Upgrades and Enhancements of Existing Software:

Upgrades and enhancements of existing software are expensed unless additional functionality is added and the cost is greater than **$5,000** and is a significant upgrade or enhancement.

Questions concerning capitalization of Computer Software items should be discussed with **Tim Clyde (825-5863)**, Property Accounting Services, prior to inclusion in the budget.

Generation Employee Training Costs – All employee training costs should be expensed, **except for Yards Creek.**

IT Projects – Activity allocate appropriate labor charges to IT managed projects that require Business Unit support. *All IT projects created under SC00 WBSs that are for the benefit of other Companies should have settlement rules that settle these costs to other company WBSs*. IT Department should coordinate these projects with the appropriate Business Services group.

Depreciation – The computation and application of depreciation will be the responsibility of Property Accounting Services.

Major Retirements of Plant – For retirements of plant, in which the estimated original cost exceeds $5 million, the following information is required: the month the item is being retired, the estimated original cost, and a short description of the item being retired. For all other retirements, a historical average will be used by Property Accounting Services. Retirements related to replacement WBSs should be made at the time the WBS is placed in service.

Generation Cost of Removal and Salvage – The budgeting of cost of removal and salvage will be performed by Generation. Generation cost of removal is expensed, **except for Yards Creek.**

Energy Delivery (Distribution and Transmission) Cost of Removal and Salvage – The budgeting of distribution and transmission cost of removal and salvage will be performed by Energy Delivery. For Met-Ed, Penelec, and JCP&L, the cost of removal and salvage will be expensed as a component of the depreciation expense in accordance with the current rate making. The planned cost of removal and salvage will settle to Account 403, Depreciation Expense.

Note: Cost Type is a required input field when entering the plan into the SPL (SAP Transaction GP12N). Changing the settlement rule on the WBS master data does not change the Cost Type in the plan. It is important that the WBS master data and the Cost Type are reviewed for accuracy

and consistency prior to input (Cost Type 1 is for Capital, 2 is for O&M and all other P&L items including Depreciation account 403, and 3 is for Balance Sheets accounts not considered capital).

CHAPTER 5: INTERCOMPANY TRANSACTIONS

Unless given approval by Corporate Budgets and Forecasts, General Accounting Services working with Corporate Budgets and Forecasts, will enter the budget estimates for all inter-company expenses and revenues. Corporate Budgets and Forecasts **(Mike Kreighbaum 825-2556)** will coordinate this effort. Unless approved for entry by the Business Units, inter-company expenses or revenues must be forwarded to General Accounting Services or Corporate Budgets and Forecasts for entry into the system. The required information to be forwarded includes:

- Inter-company G/L Accounts (Assoc. Company wording is typically included in the account description)
- Cost Centers
- Monthly Budget Amounts
- Description of transaction and the Cost Centers and G/L Accounts used for the offsetting revenues or expenses (if known)

Some examples of inter-company transactions include:

- Purchased Power and Revenues including RFP and POLR sales
- Interest Income or Expense from Associated Companies
- Leases including ATSI ground lease
- Internal Use of Company Electricity
- Billings between subsidiaries (Bayshore Power, FE Properties, etc.)

CHAPTER 6: FIRSTENERGY SERVICE COMPANY

Service Company Cost Centers – Budgeting Guidelines:

Direct Charging
When preparing your budget and incurring actual expenditures, it is important to consider who the beneficiary of your services is. Direct charging of time and expenses to the entity for which the services are being rendered is the preferred approach, where possible. To the extent that costs can be readily identified and associated with a specific transaction, the charging of those costs should be directed to the company(ies) receiving the goods or services, even when there is more than one receiving company.

Indirect Charging
Indirect charging through the Service Company assessment process supplements the direct charging of costs. Assessments are used to allocate the costs that were not direct charged from a cost center. Frequently, costs can not be direct charged because the recipient cannot be readily identified, or excessive administrative expense would result. Indirect charging employs the use of one of FirstEnergy's approved assessment methods. An approved assessment method is assigned to each Service Company cost center. The assessment methodology and the targeted legal entities for the Service Company cost centers can be provided by General Accounting upon request.

Service Company Assessments
Any desired change to organizational structure or revisions to the methodology used to allocate expenses from a Service Company cost center to the other legal entities must be reviewed and approved by **Joseph Mulpas, Assistant Controller (825-4049)**, prior to the change being implemented. This review process in necessary to insure that inter-company service agreements remain current and valid and that all regulatory requirements are being satisfied.

CHAPTER 7: BUDGETING REFERENCE MATERIAL

Primary Distribution Keys Used for Monthly Spreads

NOTE: Distribution Keys **do not** perform the wage escalation of your planned labor dollars. You need to plan your total gross payroll. The distribution keys are used to allocate your planned gross payroll to the appropriate months in accordance with that year's payroll calendar and wage escalation assumptions.

Please contact Mke Kreighbaum (825-2556) to request set up of new distribution keys.

2014	Distribution Key	Description
	P14S	NonBarg Bi-Weekly Pay 3.00% WRI Sep 2014
	P14B	Payroll BiWeekly 2014 3% March
	P14W	Payroll Weekly 2014 3.25% March
	PBM4	Barg Weekly Pay 2014 March 3% Inc
	PMH4	Barg Weekly Pay 2014 March 2.5% Inc
	PBW4	2014 Bi Wkly with 3.75% WRI Mar 2014
	PMY4	2014 Barg/Wkly Pay - with 3.00% WRI MAY
	P14M	Payroll BiWeekly 2014 3% May
	PMB4	2014 Bi-Weekly PR with 2.0% WRI MAY
	PJL4	2014 Barg/Wkly Pay - with 3.00% WRI JUL
	PJY4	2014 Barg/Wkly Pay - with 2.75% WRI JUL
	PAU4	2014 Barg/Wkly Pay - with 3% WRI AUG
	POC4	2014 Barg/Weekly Pay - with 3% WRI OCT
	PNV4	2014 Barg/Weekly Pay - with 3% WRI NOV
	PNO4	2014 Barg/Weekly Pay - with 2.5% WRI NOV

Other Monthly / Quarterly Distributions

Distribution Key	Description
1	Equal Distribution January - December
QMO	Quarterly - Last Month of Quarter - Mar, Jun, Sep, Dec
QTRM	Quarterly - Middle Month of Quarter - Feb, May, Aug, Nov
H1SP	First Half of Year - spreads evenly over Jan - Jun
H2SP	Second Half of Year - spreads evenly over Jul - Dec
Q1SP	First Quarter Distribution - Spread evenly over Jan - Mar
Q2SP	Second Quarter Distribution - Spread evenly over Apr - Jun
Q3SP	Third Quarter Distribution - Spread evenly over Jul - Sep
Q4SP	Fourth Quarter Distribution - Spread evenly over Oct - Dec
JAN	January Only
FEB	February Only
MAR	March Only
APR	April Only
MAY	May Only
JUN	June Only
JUL	July Only
AUG	August Only
SEP	September Only
OCT	October Only
NOV	November Only
DEC	December Only

Payroll Accounting Periods

PAYROLL ACCOUNTING PERIODS - YEAR 2014

BI-WEEKLY

Acctg Month	End Date			Posting		
	Sat - Fri	Sun - Sat	Mon - Sun	Date	Weeks	Hours
January	01/24/2014	01/25/2014	01/26/2014	01/31/2014	6	240
February	02/21/2014	02/22/2014	02/23/2014	02/28/2014	4	160
March	03/21/2014	03/22/2014	03/23/2014	03/28/2014	4	160
April	04/18/2014	04/19/2014	04/20/2014	04/25/2014	4	160
May	05/16/2014	05/17/2014	05/18/2014	05/23/2014	4	160
June	06/13/2014	06/14/2014	06/15/2014	06/20/2014	4	160
July	07/11/2014	07/12/2014	07/13/2014	07/18/2014	4	160
August	08/22/2014	08/23/2014	08/24/2014	08/29/2014	6	240
September	09/19/2014	09/20/2014	09/21/2014	09/26/2014	4	160
October	10/17/2014	10/18/2014	10/19/2014	10/24/2014	4	160
November	11/14/2014	11/15/2014	11/16/2014	11/21/2014	4	160
December	12/12/2014	12/13/2014	12/14/2014	12/19/2014	4	160
					52	2080

WEEKLY

Acctg Month	End Date			Posting		
	Sat - Fri	Sun - Sat	Mon - Sun	Date	Weeks	Hours
January	01/24/2014	01/25/2014	01/26/2014	01/31/2014	5	200
February	02/21/2014	02/22/2014	02/23/2014	02/28/2014	4	160
March	03/21/2014	03/22/2014	03/23/2014	03/28/2014	4	160
April	04/18/2014	04/19/2014	04/20/2014	04/25/2014	4	160
May	05/23/2014	05/24/2014	05/25/2014	05/30/2014	5	200
June	06/20/2014	06/21/2014	06/22/2014	06/27/2014	4	160
July	07/18/2014	07/19/2014	07/20/2014	07/25/2014	4	160
August	08/22/2014	08/23/2014	08/24/2014	08/29/2014	5	200
September	09/19/2014	09/20/2014	09/21/2014	09/26/2014	4	160
October	10/24/2014	10/25/2014	10/26/2014	10/31/2014	5	200
November	11/21/2014	11/22/2014	11/23/2014	11/28/2014	4	160
December	12/19/2014	12/20/2014	12/21/2014	12/26/2014	4	160
					52	2080

Budget/Forecasting Transaction Overview & Template Uploads

BUDGET/FORECASTING TRANSACTION OVERVIEW

		Activity Input Planning (Hours)				
	Gross Payroll	Cost Center	Internal Orders	WBS Elements	OTL - Spec Ledger	Head Count
Planner Profile Transaction	KP04	KP04	KP04	KP04	GLPLSET	KP04
Profile	FE-CO01	FE-CO01	FE-CO01	TD-PS01 GEN-FRMF GEN-FRMN	ZZSPL902	FE-CO01
Input Transaction	KP06	KP06	KPF6	CJR2	GP12N	KP46
Layout	CC - Prime	CC - Act	OR - Act	WBS - Act	ZZSPL90	FE - SKF
4 Year Layout	CC - Prime - Y4	CC - Act - Y4	OR - Act - Y4	WBS - Act - Y4	ZZSPL90 - Y4	SKF - Y4

Notes/Versions:
Budget Input - Version 11
Forecast Input - Version 20

BUDGET TRANSACTION OVERVIEW WITH TEMPLATE UPLOADS

		Activity Input Planning (Hours)				
	Gross Payroll	Cost Center	Internal Orders	WBS Elements	OTL - Spec Ledger	Head Count
Planner Profile Transaction	KP04	KP04	KP04	KP04	GLPLSET	KP04
Profile	FE-CO01	FE-CO02	FE-CO02	TD-PS02 GEN-FRMF GEN-FRMN	ZZSPL902	FE-CO01
Input Transaction	KP06	KP06	KPF6	CJR2	GLPLUP	KP46
Template Upload	Extras > Excel Plan > Upload	Extras > Excel Plan > Upload	Extras > Excel Plan > Upload	Extras > Excel Plan > Upload		Extras > Excel Plan > Upload

Select path of text file, file description, and American decimal notation.

File Descriptions:	One year Input	Four year Input
Gross Payroll:	01_1P1_FE-CO02_002CC-PRIME-EXC	01_1P1_FE-CO02_003CC-PRIME-Y4
Cost Center (Hours):	01_1P1_FE-CO02_001CC-ACT-EXCEL	01_1P1_FE-CO02_001CC-ACT-Y4
Internal Order (Hours):	01_1P4_FE-CO02_001OR-ACT-EXCEL	01_1P4_FE-CO02_001OR-ACT-Y4
WBS Element (Hours):	01_1P7_TD-PS02_001FE-WBS-ACT2	01_1P7_TD-PS02_001WBS-ACT-Y4
SPL/Other than Labor:	07_ZZSPL90A_ZZSPL90_001ZZSPL90EXCEL	07_ZZSPL90A_ZZSPL90_003ZZSPL90-Y4
Headcount:	01_1P3_FE-CO02_001EXCEL-SKFS	01_1P3_FE-CO02_002SKF-Y4

Key Terms & Concepts

Activity Price
The price calculated for an activity type – used for charging labor hours and transportation usage to cost collectors.

Allocations
Used to: assess shared services costs; move charges to correct legal entity; and/or assign to capital where appropriate.

Assessments
Transactions that allocate costs from Cost Centers to receiver cost objects.

Cost Allocation
Distribution of costs from one collector to another to reflect actual usage or predefined rates.

Costing Sheet
Defines an overhead calculation. Contains the percentages to be applied to the base amount and the collector to be credited.

CREWS (Customer Request Work Scheduling)
Used to estimate and schedule Transmission and Distribution projects.

Customer Care Services (CCS)
The SAP R/3 software module for utility customer information.

EC-CS (Enterprise Controlling – Consolidation System)
The consolidation module of SAP R/3 used for legal consolidation reports.

Financial Accounting Module (FI)
SAP R/3's grouping of financial data required for external reporting purpose such as balance sheet, P&L statements, cash flows, and retained earnings.

Overhead Rate
A surcharge, expressed as a percentage, used to spread indirect costs over a defined base.

Project System (PS) SAP R/3 Module
Module is used to manage large projects. Accounting data used to manage WBS Elements are also located in this module.

Profit Center
Organizational unit that reflects a management-oriented structure for the purpose of internal control and reporting.

Profit Center Accounting (PCA)
A module of SAP used to manage the business by segregating costs and revenues by business units. Measures profitability by profit center or high-level business unit.

Settlement
The SAP process of allocating costs from temporary cost collectors such as orders or WBSs to other cost collectors such as FERC cost centers.

Settlement Rule
Set of instructions that define distribution of costs incurred on a temporary cost object such as an order or WBS.

Special Purpose Ledger (SPL)
A stand-alone ledger within SAP that maintains detail without creating additional master data. Used by FE to track costs by Responsible Cost Center.

Financial Accounting Module (FI)
SAP R/3's grouping of financial data required for external reporting purpose such as balance sheet, P&L statements, cash flows, and retained earnings.

Key Contacts

By Department:

Area	Key Contact	Responsibility
Corporate Budgets and Forecasts	• Gina Caskey • Mike Kreighbaum • Carrie Wokaty • Mark Dudley	• SAP specific budget system preparations • Activity prices • Communicating the dates and times for budget input • Oversight and management of the annual budgeting and forecast processes • Tracking budget status and ensuring completion of key budget mid-point deliverables • Ad-hoc budget related reporting • PCA
Business Services and Corporate Business Planning	• Gina Caskey • Mark Dudley • Carrie Wokaty	• Corporate Shared Services – budget and forecast coordination and support • HR Benefits and Special Item budgets and forecasts
Capital Management	• Megan Gallagher • Scott McBride	• Capital Management Processes
Controllers Department	• Denis Dorward • Mike Strozak • Diane McVey • Rich Snyder	• Processing/Closing of SAP Plan • Develop and input Costing sheets (overheads) • System Maintenance – Versions, SPL, CO • Accounting Issues
Business Planning & Strategy	• Paul Mallue	• Running of production cost modeling
Competitive Retail Group	• Trevor Fernandez	• Budget and forecasting of competitive retail sales, load & revenue
Rates	• Brad Eberts • Bill Moll/Rich Faschan	• Development of the Load, MWH Sales, and Wires Forecast • Forecasting of regulated revenue for budgeting
Supply Chain	• David Zeigler	• Personal Printer requests

For SAP Master Data questions or to set up new Master Data for the 2014 Budget:

Master Data		
Contact:		
➢ Cost Centers – Denis Dorward 500-8678; Michael Strozak 500-6554		
➢ Internal Orders – Denis Dorward 500-8678; Michael Strozak 500-6554		
➢ Cost Elements – Will Blair 825-5866		
➢ WBS Elements – By Business Unit		
Energy Delivery Operating companies:		
The Illuminating Co	Gregory Werner	824-8783
Ohio Edison/Penn Power	Eric Weaver	835-4021
Toledo Edison	Ann Toth	883-5016
Jersey Central	Sue Gabel	200-8673
Met Ed	Pete Dragoich	500-6892
Penelec	Guy Costa	430-8874
Mon Power	Sara Cetorelli	333-7320
Potomac Edison	Clarence Haden	300-5218
West Penn	Marianne Sobota	350-5847
ED Finance	Eric Herrmann	825-5444
Fossil Generation Group	Katie Pinkus Denise Bracken	850-6820 850-7237
Nuclear (FENOC)	Katie Pinkus Desiree Etchell	850-6820 850-6877
Information Technology, Security	Mark Dudley	825-1683
Facilities	Tim Goughnour	500-6974
All Other Groups	Mike Czubinski	825-5646

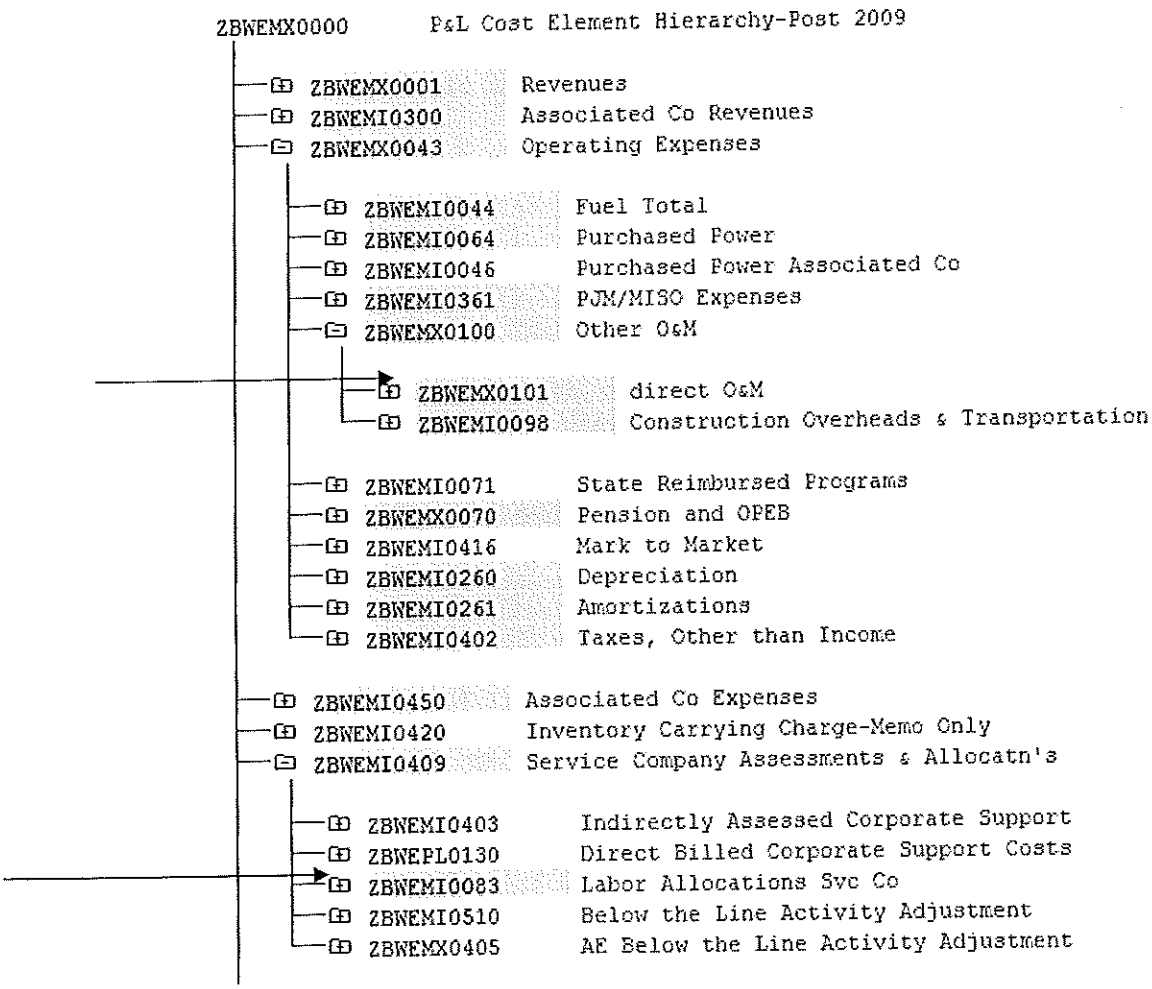
Key Contacts

For Questions by Topic or Business Unit:

Questions or Issue Topic	Name	Phone Number
Inter-company Billings	Mike Kreighbaum	825-2556
General SAP	Mike Kreighbaum	825-2556
	Mark Dudley	825-1683
	Carrie Wokaty	825-6005
	Marie Rote	825-3854
Profit Center Accounting	Mike Kreighbaum	825-2556
	Carrie Wokaty	825-6005
FE Solutions	Paul Mallue	850-7254
	Andy JayJack	850-7332
	Katie Pinkus	850-6820
Fossil Generation Group	Denise Bracken	850-7237
	Katie Pinkus	850-6820
Nuclear (FENOC)	Desiree Etchell	850-6877
Records Management/Corporate/Real Estate	Marie Rote	825-3854
Energy Delivery Business		
The Illuminating Co	Gregory Werner	824-8783
Ohio Edison/Penn Power	Eric Weaver	835-4021
Toledo Edison	Ann Toth	883-5016
Jersey Central	Sue Gabel	200-8673
Met Ed	Pete Dragoich	500-6892
Penelec	Guy Costa	430-8874
Mon Power	Sara Cetorelli	333-7320
Potomac Edison	Clarence Haden	300-5218
West Penn	Marianne Sobota	350-5847
Utility Support	Eugene DeChellis	825-7969
Customer Service & EE (Energy Efficiency)	Rob Wemhoff	825-7981
Finance	Marie Rote	825-3854
General Counsel (Legal, Claims, Communications, Corp. Affairs, Government Affairs)	Marie Rote	825-3854
Human Resources	Marie Rote	825-3854
Information Technology	Mark Dudley	825-1683
Supply Chain	Mark Dudley	825-1683
Corporate Security, Flight Operations	Mark Dudley	825-1683

Responsible Direct Cost O&M Reporting – Cost Elements Included

Use SAP Transaction KAH3 to view the Cost Element hierarchy shown below. Cost Element Groups **ZBWEMX0101 and ZBWEMI0083** are the two groups included in direct cost O&M reporting.



Corporate Shared Services – Professional & Contractor Services - Guidelines

GL	GL Short Name	GL Long Name	General Description	CSS Description/Examples
550100	OutContrctProNonLeg	Outside Services/Contractors - Professional Non-Legal	Service Contracts for unique skill-sets that we don't do in-house.	Security Equipment Installation & Investigations, Software Application Consulting/Training, Lobbying Firms, Ethnics Vendors, Expert Legal Witness, and Facility "White" Collar - Engineering, Electrical, etc.
550200	OutContractProLegal	Outside Services/Contractors - Professional Legal	Legal Fees/Legal Expenses	Law Firms Only
550300	OutContract-Other	Outside Services/Contractors - Other	Facilities	Security Guards, Annual Shareholders Meeting, Facility "Blue Collar" Contractors - Janitorial, Landscaping, Snow removal, etc.
550310	OutContractTreeTrim	Outside Services/Contractors - Tree Trim	Major Storm Deferrals	Major Storm Deferrals
550320	OutContractTempAgnc	Time and Material Contractor	Temp hires not managed by a staff service provider.	Guidant, Jet Professionals
550500	ONSITECONSLT/STFFAUG	On-Site Consultants/Staff Augmentation	Managed Service Provider - used to manage co-employment issues	Guidant, Garrettcom Utility Networks
550503	Envrmnt Wrk & Comp	Environmental Work and Compliance	Environmental	Warrenton River Terminal - Environmental

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Fossil – Professional & Contractor Services Guidelines (pgs. 30-31)

GL	GL Short Name	GL Long Name	General Description	Fossil Description/Examples
550100	OutContrctProNonLeg	Outside Services/Contractors - Professional Non-Legal	Labor outside of the plants possessing skills/knowledge that the plant does not have.	Examples include: NDE testing, Divers, Hydrochem (hydro blasting), Training Vendors (providing training on and off site), Guest Speakers, Inspection Services, Lab testing/services, Calibration, Non-repair/non-refurbishment of equipment, Welding Inspectors (x-ray team), Screening Systems International, David C Kissig Enterprises Inc., Turbine Services Incorporated, Structural Integrity Associates, Janx, Surveying, Schedulers, Ardmore, Gas line maintenance.
550105	OutsideSrvsContFees	Outside Srvs/Contractors - Profess Conting	Contingency Fees (jefferson wells for example)	Contingency and incentive fees paid to vendors.
550200	OutContractProLegal	Outside Services/Contractors - Professional Legal	Legal Fees/Legal Expenses	FERC relicensing (primarily used by CT/Hydro plants)
550210	OutContractEngineer	Outside Services/Contractors - Engineering	Contractors asked to provide engineering analysis/studies, project support, or technical development that cannot be completed with in-house engineering staff.	Examples include: Monitoring wells, Marland, RE Warner Consultants helping with outages, GE Energy, Kleinschmidt, Alstom, Siemens, Middough, Door maintenance (CT/Hydro).
550300	OutContract-Other	Outside Services/Contractors - Other	Facilities related work	Examples include: Scrap Removal, Janitorial work, Lawn care, Snow removal, Garbage and Sewage removal, HVAC/ Non-Plant Equipment, Sirens maintenance, Building and structures maintenance, General Pest Control, Elevator repairs, Grounds and roads maintenance, Auto Repair, Laundry Services, Fence Repairs, US Coast Guard, Fire Inspections, Vegetation Management.

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GL	GL Short Name	GL Long Name	General Description	Fossil Description/Examples
550305	OutContract-ProjMgmt	Outside Services/Contractors - Project Mgmt	Consultants providing project management services such as costing reports.	Examples include JR Johnson, Sargent and Lundy.
550335	OutContrRepairRefurb	Outside Services/Contractors - Repair/Refurbishment /Overhaul of Plant Equipment	Off-site labor repairing/refurbishing/replacing plant production equipment.	Examples include: Repair/refurbish valves, motors, circuit boards, etc.; CMT for Motor repairs, Cleveland Valve & Gauge for valves, Columbus Equipment Company, City Machine Technologies Inc., Monarch Electric Service Company, 3-D Service LTD.
550500	ONSITECONSLT/ STFFAUG	On-Site Consultants/Staff Augmentation	Managed Service Provider - used to manage co-employment issues	Example: Guidant
550501	PRIMMNT CONTRCRAFT	Primary Maintenance Contractor - Craft	On-site craft labor	Examples include: Enerfab, outage work/support, GMAs for bringing in Boilermakers, Insulators, Electrical Contractors, Mechanical Contractors, Patent Construction Systems, Enerfab, Burnham Industrial Contractors, McCarl's Incorporated, ERB Electric Company, Crane Inspections.
550503	Envrmnt Wrk & Comp	Environmental Work and Compliance	Contractors working on Environmental projects or performing work in support of Environmental Compliance.	Examples include: any fees, Consulting services, Test monitors, Replace monitors/analyzers, Ash site maintenance, Cleaning spills, air/water waste, Performing lab work.
550513	OnSiteContractedLbr	On-Site Contractor Labor	Labor outside of the plants providing "turn-key solutions".	Examples include: Fluor, Stein (preventative maintenance).

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Fossil - Project Construction – Professional & Contractor Services Guidelines

GL	GL Short Name	GL Long Name	General Description	Fossil - Project Construction Description/Examples
550100	OutContrctProNonLeg	Outside Services/Contractors - Professional Non-Legal	Labor outside of FirstEnergy possessing specialized skills/knowledge that we do not have in-house.	Examples include: Print Services, Nurses, Investigation Services, Background Checks/Investigations, Training, Inspection Services.
550105	OutsideSrvsContFees	Outside Srvs/Contractors - Profess Conting	Incentive fees	Examples include: Incentive arrangements, Contractor Shared Savings (for example B&W), Contractor Bonuses and Incentives.
550210	OutContractEngineer	Outside Services/Contractors - Engineering	Contractors asked to provide engineering analysis/studies, project support, or technical development that cannot be completed with in-house engineering staff.	Examples include: Conceptual Designs, Detailed Design Mods, Eng. Studies, Non-Mod, Calculations, Evaluations.
550300	OutContract-Other	Outside Services/Contractors - Other	Facilities related work	Facilities related work such as: Scrap Removal, Janitorial work, Lawn care, Snow removal, Garbage and Sewage removal, HVAC/ Non-Plant Equipment, Sirens maintenance, Building and structures maintenance, General Pest Control, Elevator repairs, Grounds and roads maintenance, Auto Repair, Laundry Services, Fence Repairs, US Coast Guard, Fire Inspections, Vegetation Management.
550305	OutContract-ProjMgmt	Outside Services/Contractors - Project Mgmt	Consultants providing project management services such as costing reports.	Examples include JR Johnson, Sargent and Lundy.
550501	PRIMMNT CONTRCRAFT	Primary Maintenance Contractor - Craft	On-site craft labor	Examples include: Enerfab, GMAs for bringing in Boilermakers, Insulators, Electrical Contractors, Mechanical Contractors.
550513	OnSiteContractedLbr	On-Site Contractor Labor	Fixed price, milestone payment, or other "turn key" type purchase agreement.	Examples include: OEM contracts (B&W), EPC contracts (Bechtel), Patent, ERB, contractors for excavating, painting, etc.

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Nuclear – Professional & Contractor Services Guidelines (pgs. 33-34)

GL	GL Short Name	GL Long Name	General Description	FENOC Description/Examples
550100	OutContrctProNonLeg	Outside Services/Contractors - Professional Non-Legal	Service Contracts for Unique skill sets that we don't do in-house	Divers, Vendor Reps, Training Vendors (providing training on and off site), Guest Speakers, Inspection Services, Vendor Source Inspections, Refueling Services, Chemistry Services, RP Services (excluding on-site support), Laundry Services, Management requested contractors/facilitators, Lab testing, Calibration of M&TE, Software customization (firm price), CNRB Members, Investigation Support, TLD Contracts, Supplier List Updates, ANI Support, Corrective Action Program Support, Print Services (Kinkos), Bulk Gas Delivery, Demurrage. Refer to cost element 550513 to ensure correct placement of vendor.
550210	OutContractEngineer	Outside Services/Contractors - Engineering	Engineering Expenses	Engineering support occurring predominantly offsite, Conceptual Design, Detailed Design Mods/ECR, Eng. Studies, Non-Mod, Calculations, Evaluations. Refer to cost element 550513 to ensure correct placement of vendor.
550300	OutContract-Other	Outside Services/Contractors - Other	Other	Lawn care and Snow removal, Garbage and Sewage removal, HVAC/ Non-Plant Equipment, Sirens (Maintenance), Building, Structures, Beta Security, Security Range Maintenance, General Pest Control. Refer to cost element 550513 to ensure correct placement of vendor.
550325	OutContractRadwstDsp	Outside Services/Contractors - Radwaste	FENOC specific	Transportation, Burial, Compacting, Processing and Analysis/Characterization of radwaste. Refer to cost element 550513 to ensure correct placement of resource.
550335	OutContrRepairRefurb	Outside Services/Contractors - Repair/Refurbishment /Overhaul of Plant Equipment	Self explanatory - see FENOC Description	Repair/refurbish valves, motors, circuit boards, etc. Security Repairs (Target Systems, Scope, NVG units), Beta test equipment. Refer to cost element 550513 to ensure correct placement of vendor.

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GL	GL Short Name	GL Long Name	General Description	FENOC Description/Examples
550500	ONSITECONSLT/ STFFAUG	On-Site Consultants/Staff Augmentation	Managed Service Provider - used to manage co-employment issues	Guidant
550501	PRIMMNT CONTRCRAFT	Primary Maintenance Contractor - Craft	Interfab/Day Zimmerman/etc	NPS contracted labor, site manager, administrative personnel.
550502	TIME&MATCONTR	Time and Material Contractor	Primary Security Contractor	Subcontracted outside security for Beaver Valley (Burns and Securitas).
550513	OnSiteContractedLbr	On-Site Contractor Labor	Goes back into capital allocation process for FENOC.	Contracted workers that are on site for a **continuous** period of 5 days or greater. Construction contractors other than NPS or Guidant that are brought on site to support a specific PRC, MERP, or outage project as identified by project managers. Contracted workers that are on site for a continuous period of time (e.g. 5 or greater continuous days i.e. Janitorial services). Part of fixed price, milestone payment, or other "turn key" type purchase agreement which represents the portion that is contract labor and performed on-site. Examples of included services are: Maxcom (telecommunication support), Assessment team support, Root Cause support, DZ Atlantic Group/Bartlett (RP Support), contractor Site Managers (with the exception of NPS). Excludes services with total annual cost <$15k, any materials included in the contract, and services provided on an "as needed" basis.

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Energy Delivery – Professional & Contractor Services Guidelines

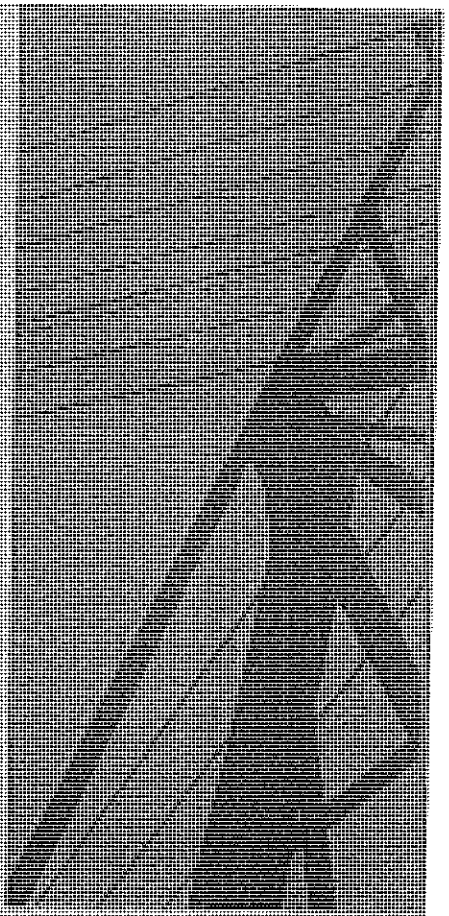
GL	GL Short Name	GL Long Name	General Description	FEU Description/Examples
550100	OutContrctProNonLeg	Outside Services/Contractors - Professional Non-Legal	Service Contracts for Unique skill sets that we don't do in-house	OSI inbound calling, Vendor services, Training
550210	OutContractEngineer	Outside Services/Contractors - Engineering	Engineering Expenses	Off-site engineering that is primarily in Transmission and Substation voltages.
550300	OutContract-Other	Outside Services/Contractors - Other	Other	Storms, Transmission aerial inspections, Facility improvements, Cable locating, Grass cutting, Snow removal, Janitorial, Heating, and Electrical repair
550310	OutContractTreeTrim	Outside Services/Contractors - Tree Trim	Tree trimming	Vegetation management
550320	OutContractTempAgnc	Outside Services/Contractors - Temporary	Temp hires not managed by a staff service provider.	Flaggers (Traffic control), Safety audits, Call-Center Temp Workers
550330	OutContrctEngDrawing	Outside Services/Contractors - Engineering Drawings	Engineering Drawings	Lightly used. Outside drafting distribution work. Roll into 550210.
550335	OutContrRepairRefurb	Outside Services/Contractors - Repair/Refurbishment/Overhaul of Plant Equipment	Outside Services/Contractors - Repair/Refurbishment/Overhaul of Plant Equipment	Outside Services/Contractors - Repair/Refurbishment/Overhaul of Plant Equipment
550500	ONSITECONSLT/ STFFAUG	On-Site Consultants/Staff Augmentation	Managed Service Provider	Guidant
550503	Envrmnt Wrk & Comp	Environmental Work and Compliance	Environmental	Claims follow-ups, Oil testing, and Clean-ups.
550506	CollAgencyCreditBur	Collection Agency - Credit Bureau	Collection Agencies	Revenue operations collections.

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FirstEnergy®

Utilities International Planner
UIPlanner - Budget Advanced

February 2014



Ground Rules

- Please turn all cell phones and pagers off, or to silent setting
- Respect those speaking and asking questions by keeping side discussions to a minimum
- Please do not interrupt the person speaking
- All unanswered questions will be placed in the "Parking Lot" and answers will be distributed later
- Have fun and enjoy the opportunity to contribute to FirstEnergy's future success!

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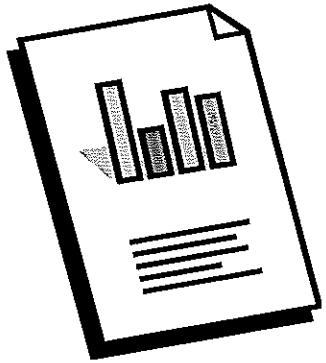
Financial Accountability Model

Financial Accountability Model

Vision – Establish a transparent financial view using standard SAP functionality

Why?

- Establishes "one source of the truth" for management reporting
- Increases accountability for total costs spent
- Reduces cost of ownership and customization of SAP



Conceptual Review

What is it?

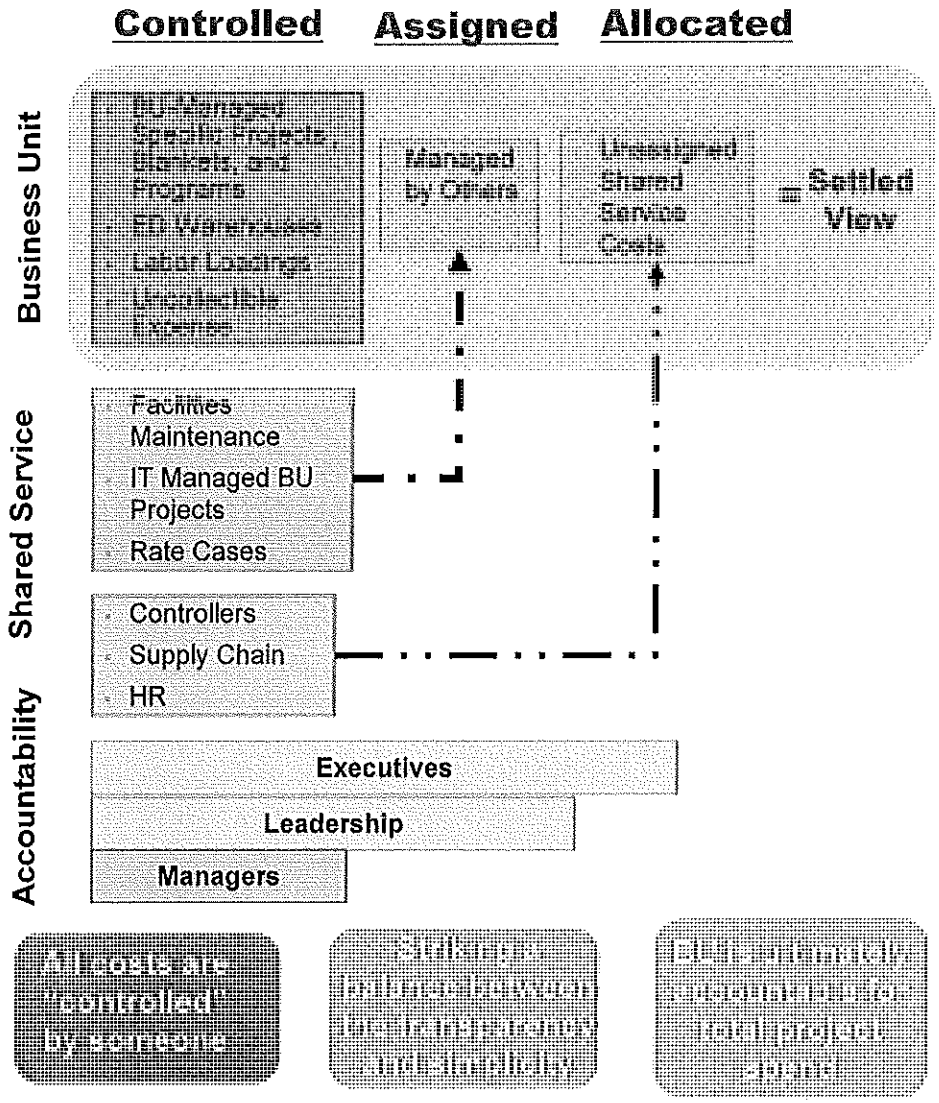
- Consistent financial view
- Establishes ownership for every dollar spent

Key Changes

- **Shift** accountability to **total spend**
- Changes in **roles and responsibilities** within budgeting process
- Changes in **level of reporting** and **reporting views**
- Changes in **target setting** within the business

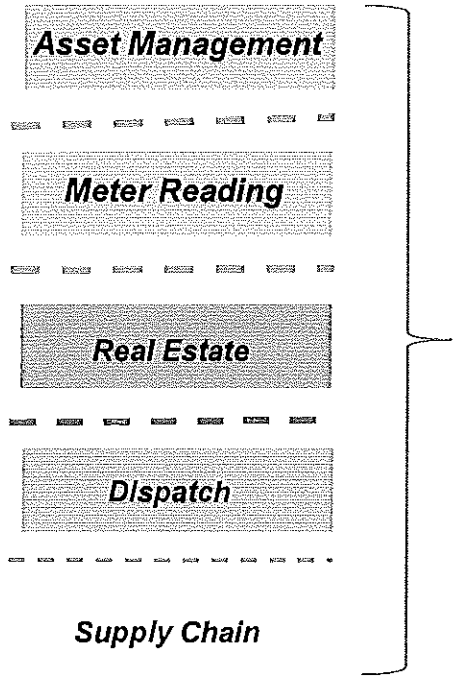
Business Impacts

- **People:**
  - Single owner accountable for total project spend, regardless of where costs originate
  - Increased roles and responsibilities for Project Owners
- **Process:**
  - Coordinate, manage, track budget and explain variances
  - Collaborate outside own organization
  - Reporting will be in alignment with the Accountability Model



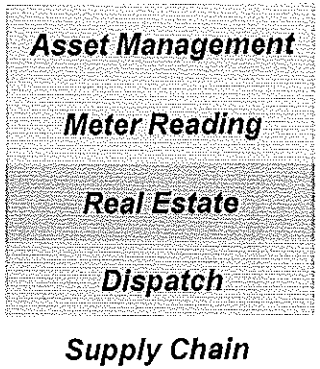
Total Project Ownership

Today



Individual ownership of pieces of a project budget

Post-Transformation



Single ownership of project budget

Outcomes

- ***One budget input for the total project including Labor & OTL***
- ***Required collaboration across the organization***
- ***Driving more comprehensive and consistent budget practices***

Roles & Responsibilities

- **Project Owners are responsible for:**
  - Developing, monitoring and updating budgeted and forecasted costs and revenues
  - Measuring and monitoring actual results, including explaining variances from budgets.
  - Collaborating with others when establishing their budgets, updating their forecasts, analyzing their actuals, and explaining variances between budget, forecast, and actual results
- **The responsibility for entering budgets and forecasts vary by Business Unit**
- **Standard financial management reports exist to support Cost Owners**

Business Unit Costs will be managed in one of two ways:

(1) Cost Owner Managed

- The labor, other-than-labor, and revenues will be assigned a specific owner (a cost center) in SAP
- Owners will be specific to each BU and each work type (e.g. blankets, programs, etc.)
- Includes Controlled, Assigned, and Allocated costs
  - *For a list of owners, by work type, by Business Unit, refer to the Financial Accountability Model policy on the FirstEnergy Today portal at: Communities>Finance>Policies and Procedures>FiT folder.*

(2) Line Item Managed

- Specific income statement line items not included above (i.e. interest expense, fuel, purchased power, etc.) will be centrally managed by defined group(s)
- This ownership is not assigned in the system but is implied based on the management of those revenues and costs

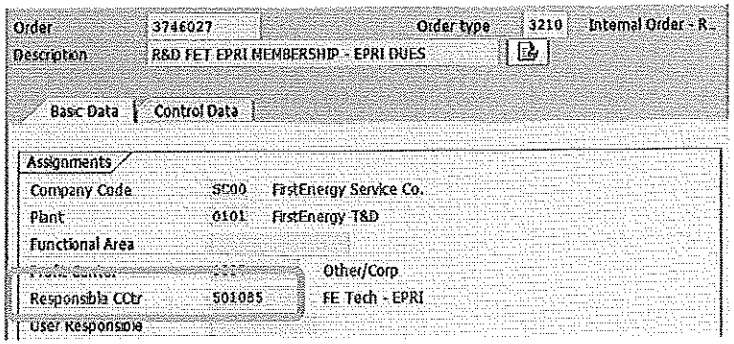
Illustrative Income Statement

Line Item	Ownership Type
Electric Revenues	
PJM/MISO Revenues	
Non-kWh Revenues	
Forfeited Discounts and Rental Revenue	
Miscellaneous Service Revenue	
Interest and Dividend Income	
Miscellaneous Revenues	
Other Income	
Other Revenues - Associated Company	
Total Revenues	
Fuel Total	
Purchased Power Total	
Fuel & Purchased Power	
O&M - Labor	
O&M - OTL	
Dues, Fees, Licenses	
Lease/Rental Costs Total	
General Business and Travel	
Materials and Equipment	
Professional and Contractor	
Uncollectible Exp	
Other OTL Total	
Other OTL Deductions	
Construction Overheads & Transportation	
Total O&M	
PJM/MISO Expenses	
State Reimbursed Programs	
Pension & OPEB	
Depreciation & Amortization	
Taxes, Other Than Income	
Operating Expenses - Associated Company	
Total Operating Expenses	
Operating Margin	
Service Company Billings	
Sale/Leaseback	
Interest	
Other Expenses	
Income Before Taxes	
Income Taxes	
Net Income	

Legend	
Controlled Costs + Settlements & Assessments	
Line Item Controlled	
Allocated	

How is Cost Ownership Assigned?

- **Representatives from each Business Unit were involved in assigning cost ownership to cost collectors**
  - Cost Owner field is a field on the SAP cost collectors called "Responsible Cost Center"
  - A Cost Owner is required on all cost collectors



- **A new cost center hierarchy, ZBWCAM0000, drives Standard Financial Management Reporting**
  - The hierarchy will provide line-of-sight into Controlled, Assigned, and Allocated costs

ZBWCAM0000 Accountability Model - CstCtr Hierarchy

- ZBWCAM1000 FEU
  - ZBWCAM1001 AYE Utilities
  - ZBWCAM1002 AYE Fed Reg Transm Segment
  - ZBWCAM1004 Compliance & Regulated Services
  - ZBWCAM1007 Customer Service
  - ZBWCAM1034 Distribution Support
  - ZBWCAM1068 ED and CS Senior VP
  - ZBWCAM1069 ED Safety Admin and Planning
  - ZBWCAM1070 Energy Efficiency Group
  - ZBWCAM1076 FE Utilities Admin
  - ZBWCAM1077 FERC - FE Utilities
  - ZBWCAM1098 Special Items - FEU
  - ZBWCAM1113 Transmission
  - ZBWCAM1127 Transmission Facilities Agreement
  - ZBWCAM1131 Utility Operations
- ZBWCAM2000 FES/FEG
  - ZBWCAM2001 FE Solutions
  - ZBWCAM3001 FE Generation
- ZBWCAM4000 Shared Services
  - ZBWCAM4001 AYE Other/Corp
  - ZBWCAM4002 Executive Administration
  - ZBWCAM4006 Finance Group
  - ZBWCAM4043 Human Resources Group
  - ZBWCAM4055 Legal and External Affairs
  - ZBWCAM4081 Special Items - Shared Services
  - ZBWCAM4085 Strategic Planning and Operations
- ZBWCAM9000 Unused

Benefits of Financial Accountability Model

- Identifies a single, accountable owner regardless of where costs originated
- Provides transparency and visibility into our financial statements
- Promotes an understanding of total spend by the work completed instead of a view by department
- Reduces customization and ad-hoc reporting
- Facilitates standard financial management reporting

Leadership Feedback:

- Overwhelming support for moving to one financial view
- Requires clearly defined guidelines
- Governance is required for sustainability

Q1) What is a 'Cost Owner'?

A. A Cost Owner is a cost center in SAP (not a specific individual) assigned to each and every cost collector.

Q2) How were Cost Owners determined for each cost?

A. A review was completed with each of the Business Services organizations to determine the appropriate Cost Owner for each dollar spent. Activities included:

- Validation of Cost Owner assignment to each cost collector
- Verification that Cost Owner hierarchy supports management reporting
- Comparison of "as-is" with "to-be" reporting and explanation of differences in reporting and accountability throughout the business
- Reconciliation of new reports to the existing internal reports/financial statements

Q3) Who are the Cost Owners?

A. Refer to the Financial Accountability Model policy, available effective January 1, 2014, for a list of work types and associated Cost Owners by Business Unit. The policy can be found on the FirstEnergy Today portal under Communities >Finance >Policies >FiT.

Q4) What if the Cost Owner disagrees with costs from another department?

A. The Cost Owner should discuss costs with the originating department. Changes to Cost Owners must be carefully controlled and are not permitted without prior approval. A process exists to request and receive approval for Cost Owner changes.

Refer to the Financial Accountability Model policy on the FirstEnergy Today portal at Communities>Finance>Policies and Procedures>FiT for more information.

Q5) When will the Financial Accountability Model be implemented?

A. It will form the foundation of all Reporting and Budget, Forecast, Planning activities beginning January, 1 2014.

Q6) The direct view (z8/z9) is going away. What do I use for my project or cost center reporting?

- Refer to chapter 2, Standard Financial Management reporting, of this training to understand the cost and labor reports available to you.

UIPlanner Software Overview

UIPlanner Overview

- Utilities International, Inc. is the leading provider of integrated planning solutions for utilities and related businesses

- UIPlanner (UIP) is a multi-user database system that supports Accounting and Finance functions

Planning
- Financial plans
- Strategic plans
- Regulatory plans

Treasury
- Daily forecasts
- Monthly forecasts
- Financing strategy

Tax
- Tax plans
- Tax strategies
- Actual taxes

Accounting
- Allocations
- Variance analysis
- Financial reporting

Budget Admin.
- Consolidation
- Administration
- Rolling forecasts

Regulatory
- Cost of service
- Rate design
- Clauses / riders

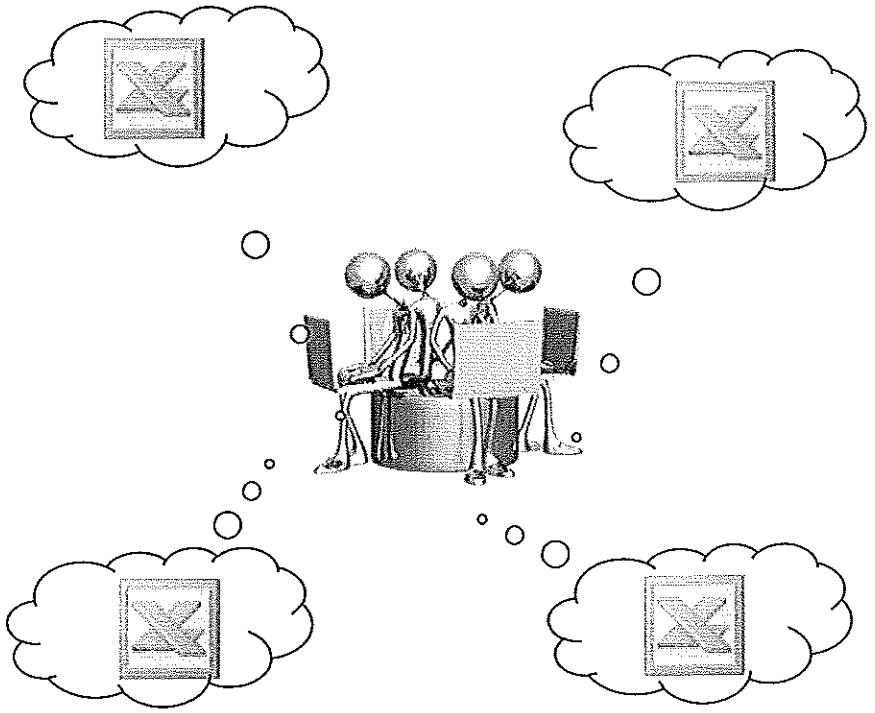
Customer Service
- Bill forecasts
- Analytics
- Energy Efficiency

Budget Users
- Unit-based budgeting
- Labor planning
- Project forecasts

Business Analyst
- Project evaluation
- Commitment tracking
- Performance analysis

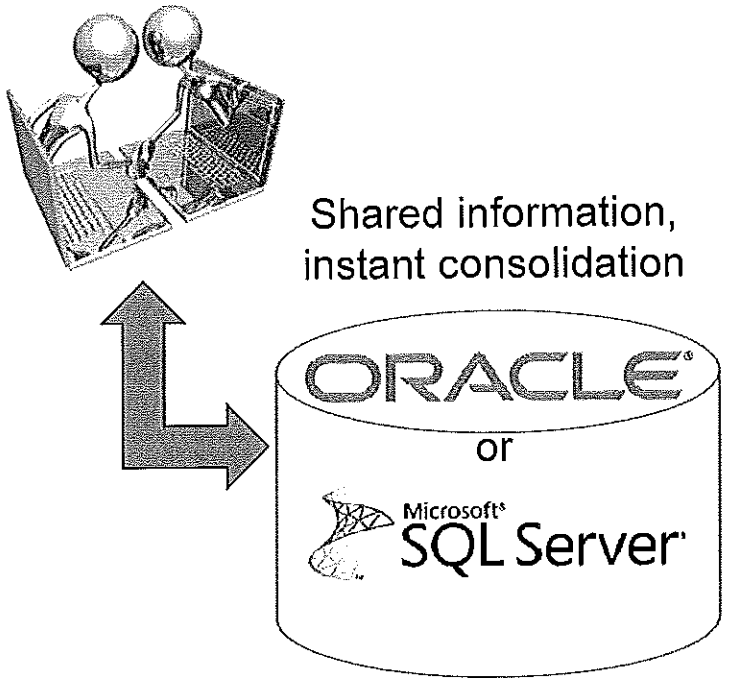
UIPlanner Overview

Individual Spreadsheets



Relies on manual processes to share and consolidate data

Integrated UIPlanner

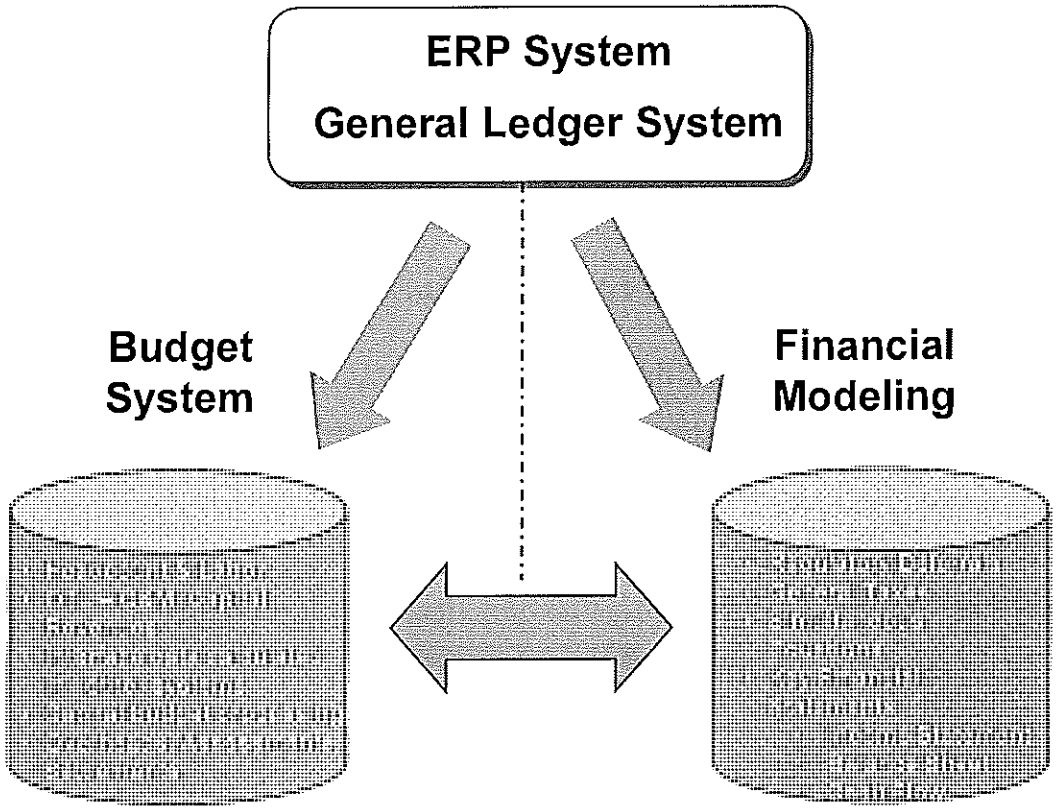


More productive, efficient, and less prone to error

UIPlanner Overview

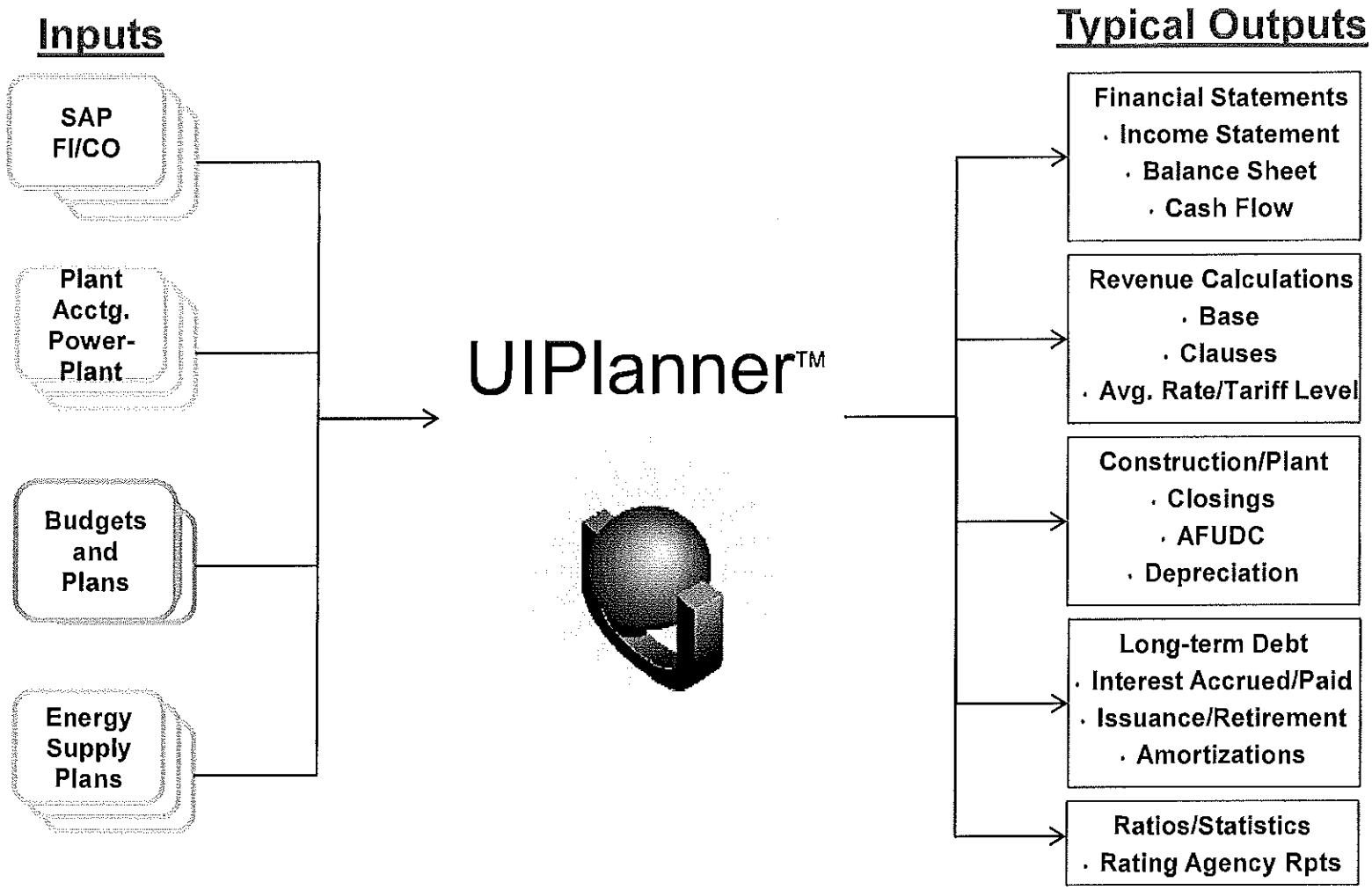
- UIPlanner can interface budget, forecast, plan results directly from a Company's ERP or General Ledger System to either the UIP Budget System or Financial Model

- Many Utilities utilize the Financial Modeling tool to manage their financial planning and regulatory outcomes



UIPlanner Overview

UIPlanner integrates data from multiple sources



UIPlanner Overview

Process Improvements

Move to multi-year forecasts

- Expand beyond current year
- Unlimited planning horizon (e.g. 5, 10, 20 year)
- Budget process practices

Improve variance explanation process

- Focus on business drivers
- Avoid unknown variances
- Shorten the cycle time to explain and respond

System Improvements

Technology for multi year forecasts

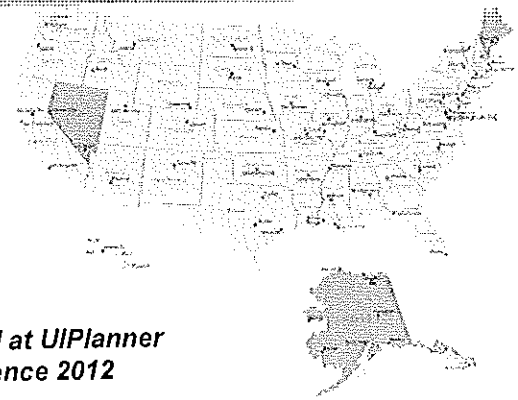
- Merge actuals with forecast
- Lock months of actuals
- Refer to prior forecasts

Technology for variance explanation

- Drilldown into logic and data
- Ability to add comments to reports by department/cost center

UIPlanner integrates all aspects of the budgeting and planning process

UIPlanner Overview



- **The 30 largest U.S. Utilities using the UIPlanner financial modeling tool – *not all clients shown are utilizing the UIPlanner budget entry system***
- **Proven across jurisdictions – regulatory calculations in 47 states**

Client list presented at UIPlanner Users Conference 2012

Exelon ✓ | Pacific Gas and Electric Company ✓ | AES ✓ | ✓ Sempra Energy | Ameren ✓

Duke Energy ✓ | Edison International ✓ | ppl ✓ | PSEG | Bonneville Power Administration

nationalgrid The power of action ✓ | MidAmerican Energy Holdings Company ✓ | Entergy ✓ | Xcel Energy ✓ | Northeast Utilities ✓

Southern Company Energy to Serve Your World ✓ | FirstEnergy ✓ | conEdison | nrg | CenterPoint Energy

FPL ✓ | TVA ✓ | Energy Future Holdings | ✓ DTE Energy | NiSource ✓

AEP ✓ | Dominion It all starts here ✓ | Progress Energy ✓ | elpaso | Los Angeles Department of Water & Power ✓

✓ = Client ✓ = Not client; attended conference

Budget Forecast Plan Key Process Overview

Key Process Changes

- Budget entry and analysis will not be managed in SAP. UIPlanner will now perform all budget related functions.

- Long-term planning (5 year) will be integrated with current year budget and forecast processes
  - Current year monthly and quarterly multi-year forecasting process is being implemented
  - Actuals will be interfaced to UIPlanner on a monthly basis
    - Cost collector, cost element and GL level
  - Transaction detail will not be interfaced to UIPlanner but will be available in the Common Data Source (CDS)
- Budget close processing performed within UIPlanner for all years entered
- Close process for actuals continues in SAP
- UIPlanner replaces xRPM as the Corporate capital planning tool and FES/FEG One List

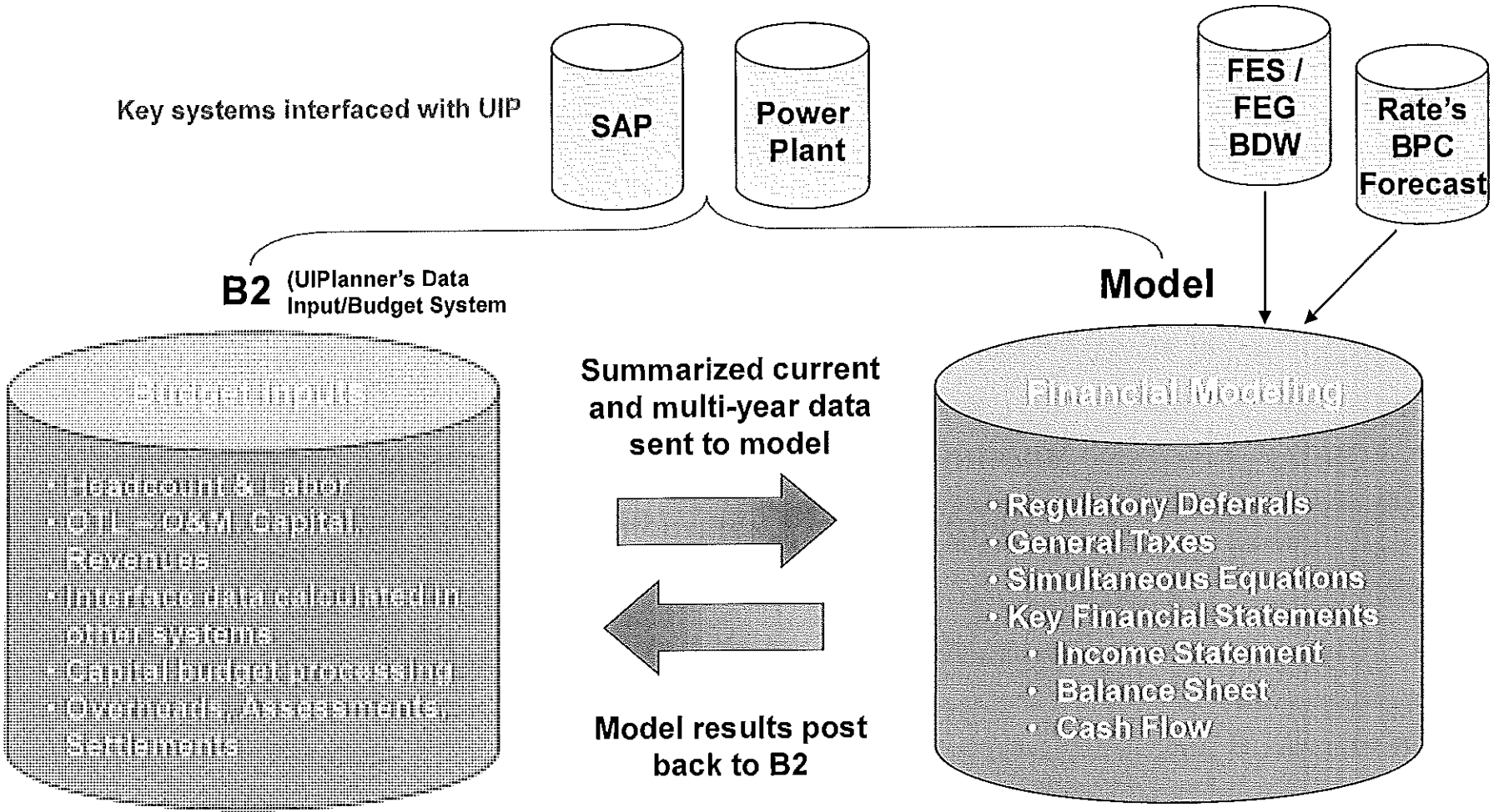
Key Process Benefits

- Consistent approach for budget, forecast, and plan; standard and efficient processes with integrated software tools
- Automated interfaces to source data reducing manual data manipulation
- Reduced cycle time to close budget
- UIPlanner replaces Midas (FE's current financial modeling tool) which is no longer supported by the vendor
- Monthly processing eliminates pencil changes and captures adjustments each forecast run
- Enhancement of integrated forward-looking scenario analysis for the company

The current year annual budget and forecast process provides the Company with a method to quantify and report the current year's expectations and help drive the Company toward achieving financial and operational objectives. The budget and forecast process also assists with facilitating the efficient usage of the Company's financial resources and allows the measurement of actual performance against projections.

Budget, Forecast, Plan Environment

UIPlanner Integrated Planning Tool
Current and Multi Year



Budget, Forecast, Plan Process

Today

Three separate processes for budget, forecast, and plan

Annual Budget

- Current year annual projection of staffing (employee headcounts), revenues, and expenses (Income Statement, Capital and Other)

Current Year Forecast

- Revised projection of the current year annual budget. Revisions to the current year annual budget (e.g. 3+9, 6+6, 9+3)

Multi Year Plan

- Two or more years of projected financials. Also referred to as the multi-year plan

Post FiT

Migrating to an integrated budget, forecast and plan process

A **Annual Budget / Multi Year Plan**

- Current year (year 1) annual projection of staffing (employee headcounts), revenues, and expenses (Income Statement, Capital and Other)
- Includes multi year plan (years 2-5) identifying business initiatives and primary business drivers

B **Current and Multi Year Forecast**

- Revised projection of the current year annual budget. Monthly revisions to the current year annual budget (e.g. 3+9, 4+8, 5+7, 6+6, etc.) and multi year plan with formal multi year reporting on the quarter close

Process Steps and Key Activities

A Annual Budget / Multi Year Plan

B Current and Multi Year Forecast

1 Maintain UIPlanner System & Process
- Create New Scenario (annual/monthly)
- Run Applicable Interfaces
- Develop / Update Budget, Forecast Plan Guidelines
- Create Annual Activity Prices
- Perform Other System Functions

2 System Entry
- Employee Labor
- Allocate Labor and Non Labor
- Create/Maintain Budget Group Budget Items
- Project Planning and Tracking
- Validation Reporting
- Business Unit/Department Center Locking

3 System Administrator Activities
- Validation Reporting, Center Locking, Budget/Forecast Close, Derive FERC

4 Financial Modeling
- Move B2 Results to Model
- Move Model Results to B2

5 Reporting
- Move Processed Financial Results to Common Data Source
- Standard Reporting

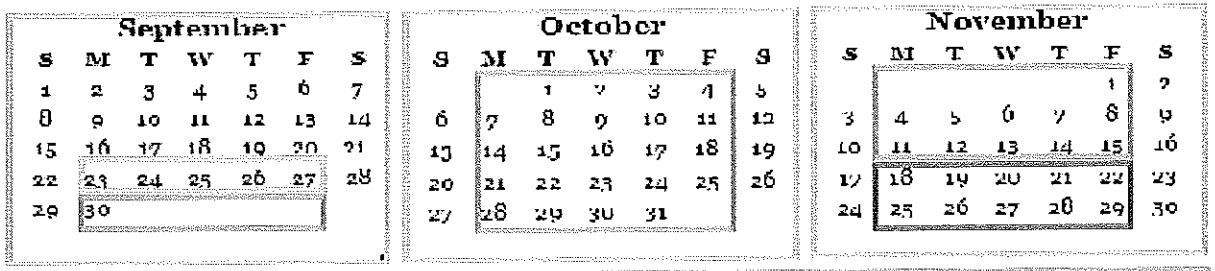
Annual Budget / Multi-Year Plan Process

Annual Budget / Multi-Year Plan Process

A Annual Budget / Multi Year Plan Process

- Traditionally starts late third quarter each year
- Results available for November Board Meeting – approval of five year plan

Year 1

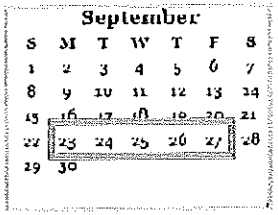


Years 2 - 5

- **Key Activities**
  - Create New Scenario (annual)
  - Run Applicable Interfaces
  - Develop Budget, Forecast, Plan Guidelines
  - Calculate Annual Activity Prices
  - Perform Other System Activities
  - Employee Labor
  - Allocate Labor and Non Labor
  - Create/Maintain Budget Group Budget Items
  - Project Planning and Tracking
  - Validation Reporting
  - Business Unit/Department Center Locking
  - System Administrator Functions
    - Validation Reporting, Center Locking, Budget Close, Derive FERC
  - Move B2 Results to Model
  - Move Model Results to B2
  - Move Processed Financial Results to Common Data Source
  - Standard Reporting

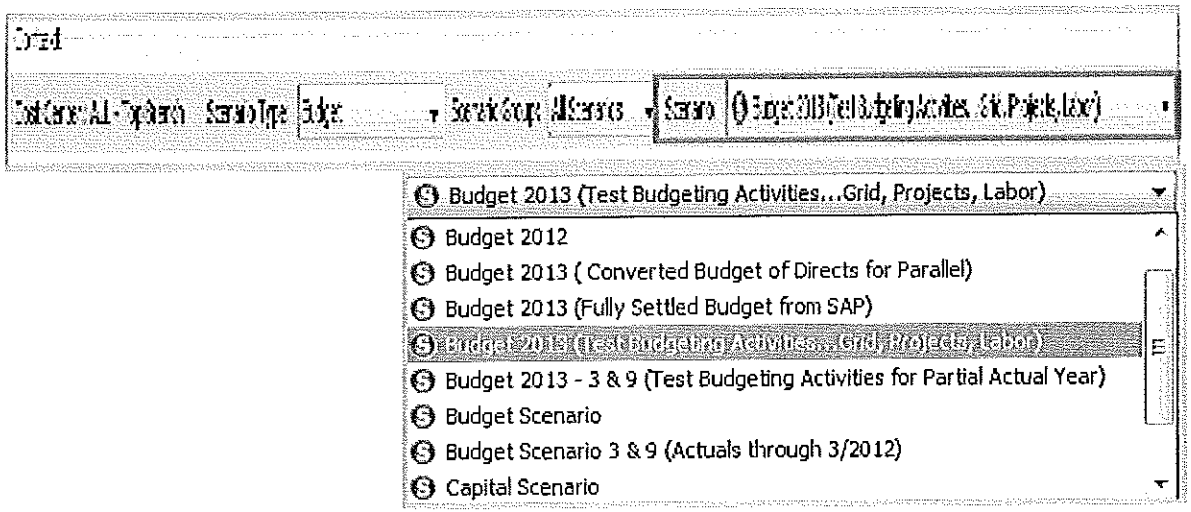
Annual Budget / Multi-Year Plan Process

1 Create New Scenario



Scenarios are similar to versions in SAP. UIPlanner will manage all the different scenarios needed throughout the year for the budget, forecast, and plan process

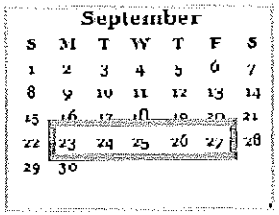
- A new scenario will be created for the annual budget process and for each monthly forecast update
- Additional scenarios can be created based on management's request
- Available scenarios will be listed via drop down box on the main menu



Annual Budget / Multi-Year Plan Process

2 Run Applicable Interfaces

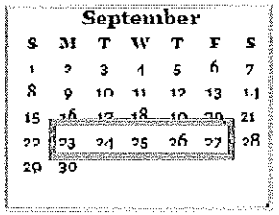
SAP will interface data to UIPlanner near real time, nightly and monthly



Near Real Time	Nightly	Monthly
• Cost Centers • Orders • Projects *(WBS project definition and WBS elements)* • Cost Elements • General Ledger Accounts • Profit Centers	• Activity Types • Companies • All related trees	• Controlling Actuals • General Ledger Actuals • Overheads • Assessments • Settlements • FERC • HR employee data • Power Plant
• Users will continue to create and manage master data in SAP • Near real time approximately every 30 minutes • On demand available	• Individual data fields available near real time – actual tree update will occur nightly	• Actuals loaded to support monthly processing • Budget close performed in UIPlanner • On demand available

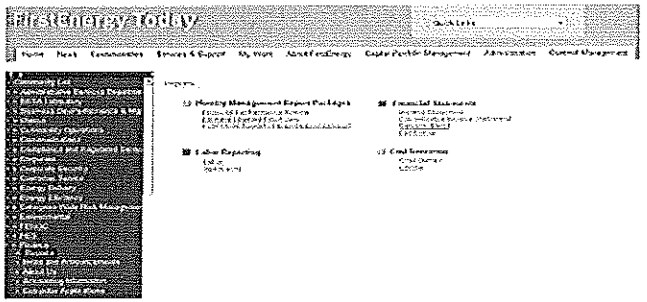
Annual Budget / Multi-Year Plan Process

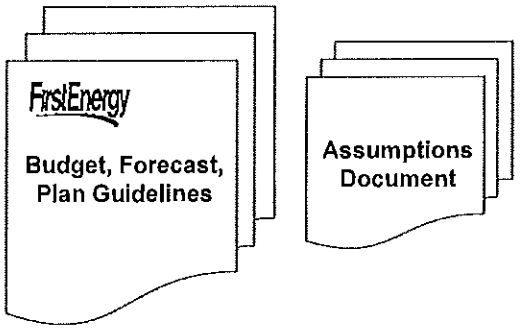
3 Develop Annual Budget, Forecast, Plan Guidelines



Guidelines will be developed and maintained to assist persons responsible with the direct input of data into UIPlanner as they prepare the annual, budget, forecast and plan

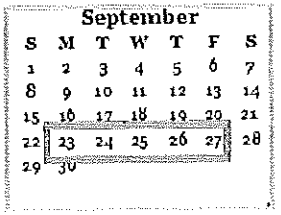
- Guidelines will cover the annual process along with the current year and multi year forecast process. Items included will cover annual calendar of events, plan assumptions, timing, person responsible and applicable targets
- Related processes such as creating and maintaining master data, financial accountability model guidelines, and reporting will be included (other FiT linked processes)
- A common data repository will be available on the FE Portal under the Finance Community. Key documents will be stored to facilitate the budget, forecast, plan process. Available in 2014
- Guidelines will be updated throughout the year, if needed, to reflect major changes as part of the monthly/quarterly forecast process





Annual Budget / Multi-Year Plan Process

4 Calculate Annual Activity Rates

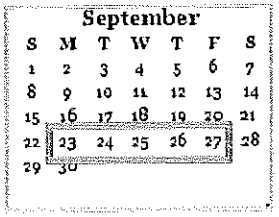


Annual activity rates will be calculated in UIPlanner prior to the start of the annual budget process. SAP HR employee data will be interfaced to UIPlanner to support this process

- **Run HR interface**
  - Import Employee data containing employee salaries, vacation, PAD, holiday, etc,
- **Calculate employee loaded salary**
  - Labor additives (benefits, incentive compensation, payroll taxes)
  - Update union and non union wage schedules
- **Calculate productive hours by employee**
  - Vacation, PAD, holiday, meetings, and other non productive
- **Calculate activity rates**
  - Total dollars / total hours
  - Rates will be automatically calculated for the plan horizon

Annual Budget / Multi-Year Plan Process

6 Perform Other System Functions



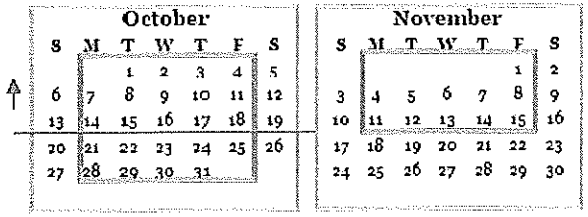
Other activities include administering user security, maintaining global assumptions, ensure system validations are current, publishing datasets and reports, etc.

- **Administer user security**
  - Add, edit, delete
  - Maintain FERC code of conduct and required reporting
- **Maintain global system assumptions**
  - Update related datasets
- **System Validations**
  - Maintain rules and validations for appropriate screens
  - Maintain interfaces
- **Other Miscellaneous**
  - Publish standard reports
  - Trouble shoot system problems
  - General system maintenance

Annual Budget / Multi-Year Plan Process

6 Employee Labor

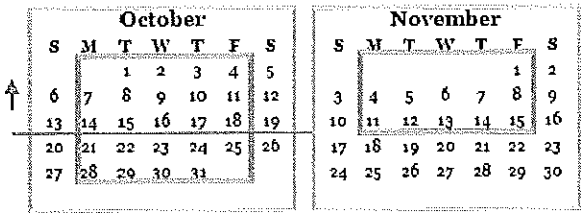
View and verify SAP HR interfaced employee data



- SAP HR data will be interfaced to UIPlanner initially for calculation of activity prices but also monthly to show employee changes and unproductive time usage
- Verify employee data - employee names, cost centers, etc.
- View/update labor data at the individual employee or summary cost center level
- Additional employee information such as vacation eligibility, available payroll hours, etc will be summarized to help facilitate building of the labor budget and monthly forecast process
- Access to the labor screens will be secured based on role and business unit/department
- User will be presented with hours and dollars at the individual employee level and summary level by Company, Cost Center, Pay Calendar, Personnel Subarea, Activity Type

Annual Budget / Multi-Year Plan Process

6 Employee Labor *(continued)*

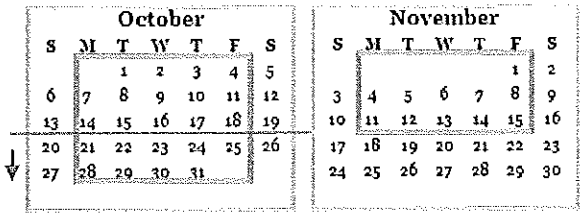


Determine number of headcounts, FTE's, vacation and PAD allocation, total hours, and total dollars by either individual employee or summary level

- Verify employee data - employee names, cost centers, etc.
- Update staffing - headcounts and FTE's
  - Additions
  - Exits (planned retirements)
  - Internal transfers
- Allocation of unproductive time - PAD, vacation, deferred vacation
- Manual salary adjustments - promotions, non ICP bonuses
- Determine overtime hours or dollars
- Note: Other than labor entry can also occur in conjunction with developing employee labor
- Cost Center Labor Hours and Dollars Available to budget in grid

7 Allocate Labor and Non Labor

Allocate hours and dollars to the various cost collectors (cost center, internal order, WBS) for capital and noncapital

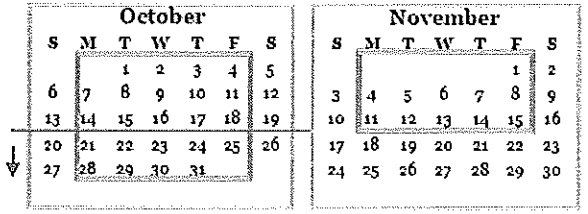


- System design follows the Financial Accountability Model where each cost collector has one owner
- Cost collector owners will be responsible for budgeting and forecasting all other than labor
- Master Data guidelines will be in place to ensure consistency across the Company
- Cost collector combinations are entered into UIPlanner via a budget grid or Excel upload
  - Budget records will be displayed for the active department or cost center selected
  - An additional project screen available to further define budget inputs
- Both hours and dollars available on grid
- Contractor hours/dollars calculation available to assist users with developing their other than labor budgets

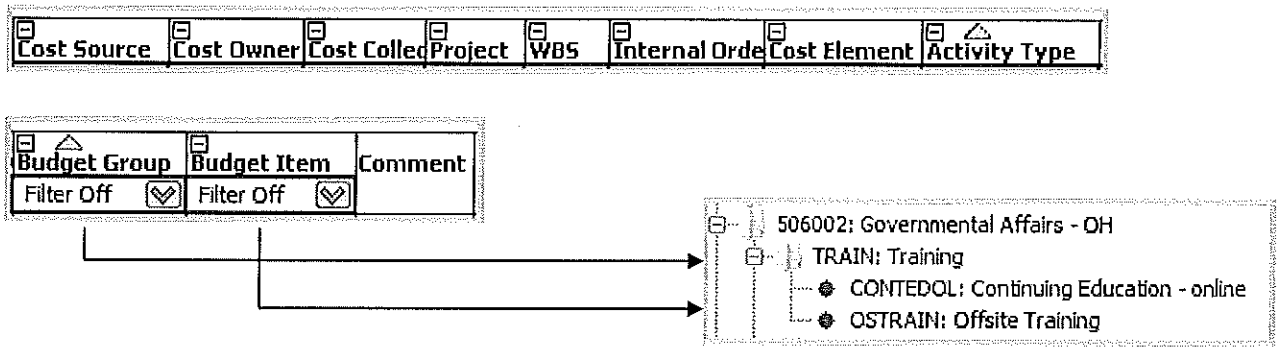


8 Create / Maintain Budget Group Budget Item

Budget groups and budget items will be utilized as part of the budget grid entry to further categorize data inputs. Utilized to assist with budget/forecast approvals. Data fields are optional



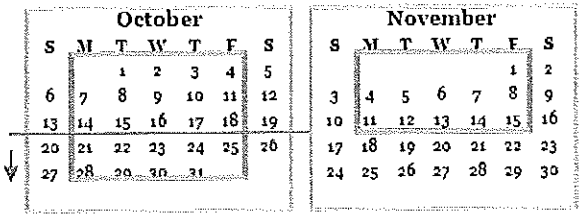
- Budget groups and budget items can be assigned to any node in the cost center tree
- The availability for use will depend on the assignment and level in the cost center tree
  - If a budget group budget item is assigned to an individual cost center then it will only be available for use with a grid combination for that particular cost center
  - Budget group and budget items set at the "all node" or top level will be available for all users



Annual Budget / Multi-Year Plan Process

9 Project Planning and Tracking

A separate project screen is available where users can house additional project information in one common place. Planning projects can be created in UIPlanner to assist with long term planning

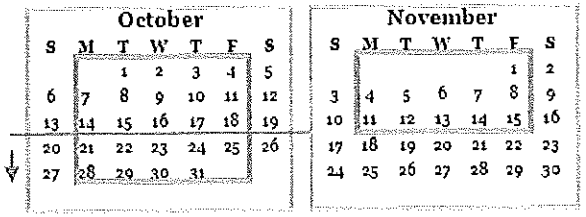


- Users will input additional project information such as project description, project sponsor, project status, etc for both SAP projects and UI Planning Projects
- Project attributes will be both required and optional
- UIPlanner will allow users to create projects for multiyear planning without having to create the project definition and WBS elements in SAP
- "Project Templates" will be interfaced and utilized from SAP as a starting point
  - Allows the project attribute values of the SAP project to be applied to the new Planning Project (project definition and WBS element level)
  - Mirroring the SAP project to the UI Planning Project ensures important attributes such as the costing sheet data is applied accurately
- When planning projects are approved during the budget year, the project definition and WBS elements will be created in SAP and interfaced in UIPlanner

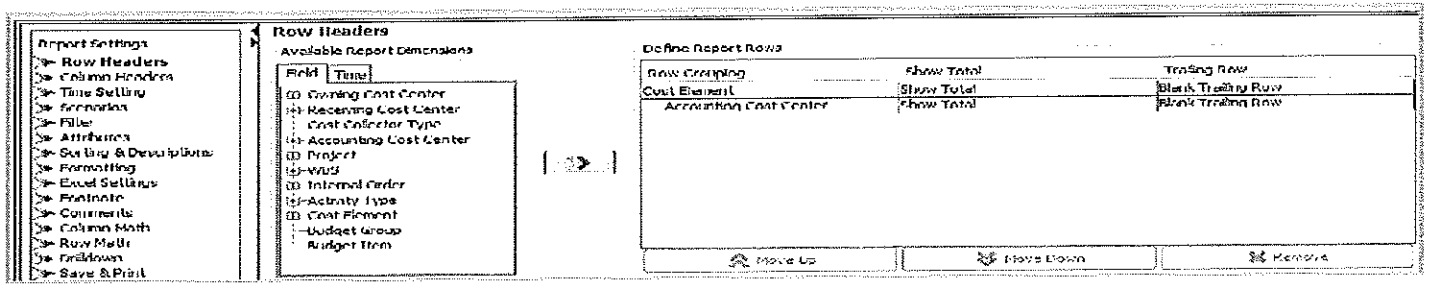
Annual Budget / Multi-Year Plan Process

10 Validation Reporting

System validation reports will be available to check user entry for budget and forecast inputs

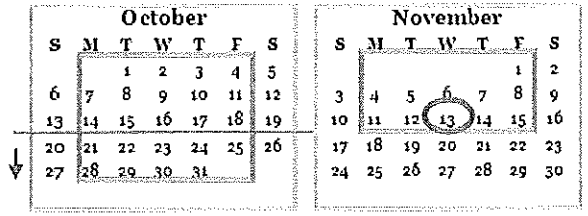


- UIPlanner reports will be available to validate system entry
- Multiple ways to view data
  - **View Reports -** standard reports by major category
  - **Create Reports** - on-the-fly reporting - menu driven. Ability to edit report rows and columns, add and delete fields, subtotal and total, formatting
  - **Report Administration** - enables user to create reports you want to quickly rerun, distribute, or edit in the future
- Certain data fields will be derived through reporting such as cost type, company code, profit center, etc.



Business Unit / Department Center Locking

Business Unit/Department approval will be required. Select users will be able to lock the cost centers for their respective areas prior to the final budget close

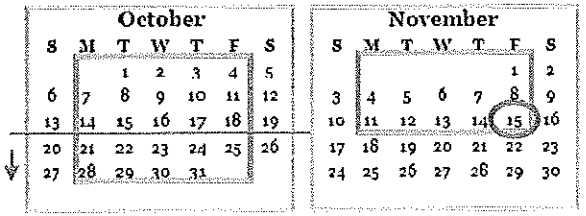


- Select users will be granted access to lock their individual business unit/department cost centers or entire group/department once the Business Unit Controller/Department Head has reviewed and approved the results
- Center locking will be considered an approval and signifies to the System Administrator that the group has completed their work and is ready for final processing
- Center locking is date stamped and identifies who locked and at what time

Annual Budget / Multi-Year Plan Process

12 System Administrator Activities

System Administrator will perform additional activities to finalize the budget/forecast process



- **Validation Reporting**
  - Verify all areas are locked
  - Review miscellaneous reports

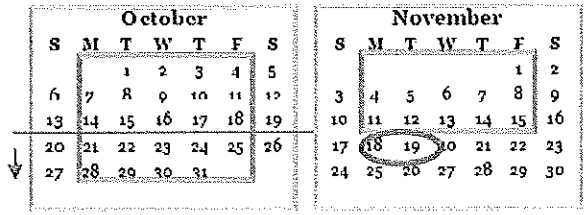
- **Administrator Center Locking**
  - Once the Business Unit/Department locks their individual groups, the System Administrator can perform an administrative lock over the entire cost center tree which signifies the scenario has been locked
  - System Administrator has the authority to open up individual centers for a particular user in the event a budget correction is needed

- **Budget / Forecast Close Process**
  - The Budget Close will be processed in UIPlanner and System Administrator will run the budget close at different intervals of the process giving the user insight into the final settled numbers
  - The close will process all years in scenario
  - A schedule will be published as part of the budget guidelines allowing users to plan accordingly
  - Budget close processing time is expected to be significantly shorter than FE's current process. Exact time for compiling and run time is not yet known
  - FERC will be derived as part of the close process

Annual Budget / Multi-Year Plan Process

13 Move B2 Results to Financial Model

Select budget entry items will be migrated from B2 to the Financial Model for further processing



- Dependent data items (interest, deferrals / riders, income taxes, general taxes) are calculations that will be automated in the model

- The model "links" the calculation of dependent data
  - Eliminates the need for manual handoffs
  - Allows for quick turnaround of changes

- New process will generate integrated financials, not just an Income Statement
  - Better insight on cash impacts
  - Monitor key financial drivers including regulated entities rate base

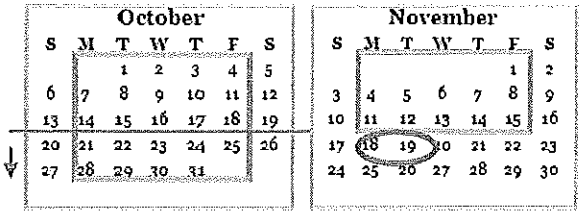
- Separate model security limits access to data
  - Not all B2 users will have access to the financial model

- Additional Model activities
  - Creating scenarios and "what if" analysis
  - Target setting and financial metrics

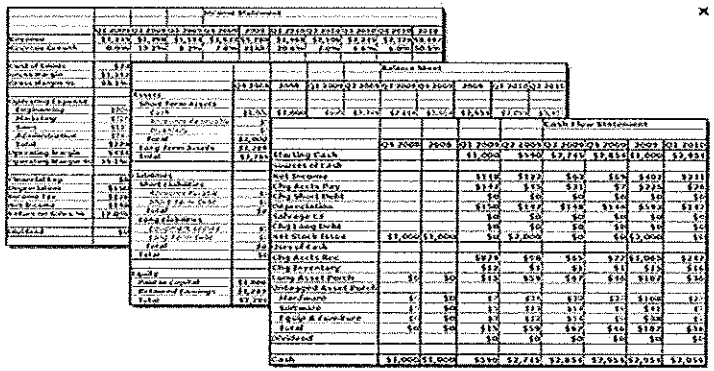
⇒ *Develop internal multi-year financial guidance and targets*

14 Move Financial Model Results to B2

Once model processing occurs, results will be posted back to B2 for users to view. Level of details and posting method is still under development



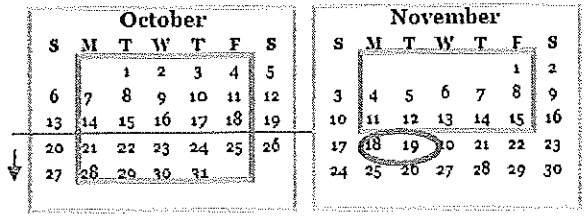
- Results from the data calculations within the model will be posted back to the B2 environment
- Calculated results will be available to view within a dataset and report
- Owners will review and validate results as part of process
- The key financial statements (income statement, cash flow, balance sheet) will also be generated as part of model processing
- Internal income statement results will be available for users to view in B2



Annual Budget / Multi-Year Plan Process

15 Move Processed Financial Results to Common Data Source

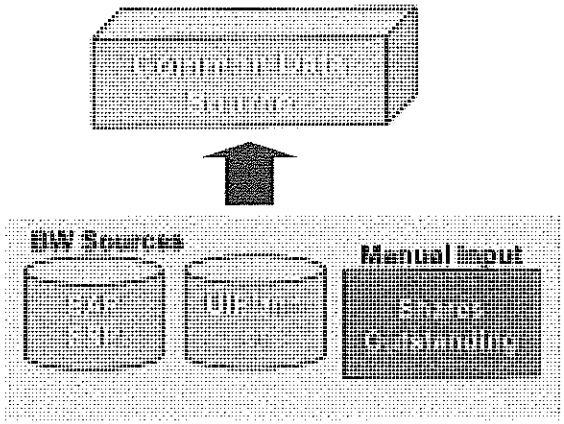
Provide standard management reporting sourced from a single, common database. Standard reporting available to ensure results are viewed consistently across the organization



- **Final processed results will be moved to the Common Data Source**
  - Separate Summary Cube allows faster report processing
  - Separate Detailed Cube simplifies variance analysis
  - Multi-year forecast data will not be sent to the BW

- **FiT Available Reports**
  - Financial Statements,
  - Monthly Management Reports
  - Cost Reporting
  - Employee Labor Reporting

Source Systems



Current and Multi-Year Forecast Process

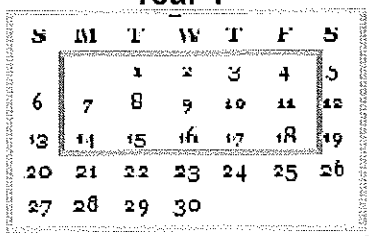
Current and Multi-Year Forecast Process

B

Current and Multi-Year Forecast Process

- Recast current month and remaining months in current year
- Update of multi-year plan
- Standard reporting will be utilized with fixed timing (FiT Reporting)
- Forecast results available each month to manage current and multi year

Year 1



Years 2 - 5

- **Key Activities**

1
- Create New Scenario (monthly)
- Run Applicable Interfaces (monthly)
  - Update Budget, Forecast, Plan guidelines
  - *Calculate annual activity prices (N/A)*
- Perform Other System Activities (if needed)
  - *Move B2 Results to Model*
  - *Move Model Results to B2*
  - *Move Processed Financial Results to Common Data Source*
  - *Standard Reporting*

2
- Employee Labor
- Allocate Labor and Non Labor
- Create/Maintain Budget Group Budget Items
- Project Planning and Tracking

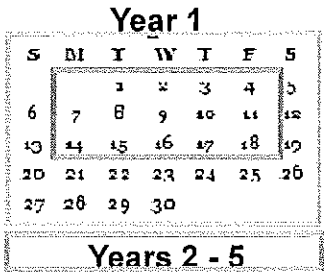
→ Reflect labor and non labor changes

  - *Validation Reporting*
  - *Business Unit/Department Center Locking*
- *System Administrator Activities*
  - *Reporting, Center Locking, Budget Close, Derive FERC*

Current and Multi-Year Forecast Process

1 Maintain UIPlanner System & Process

The current and multi-year forecast process will follow the same steps as the annual budget/multi-year plan process with several activities being modified to reflect monthly versus annual



- Create New Scenario
  - Create new version to capture recast
- Run Applicable Interfaces
  - Interface SAP monthly actuals (budget level)
  - Interface HR employee data
- Update Budget, Forecast Plan Guidelines
  - Update scenario assumptions (if needed)

Actuals load to UIP ***Recast remaining months and multi year***

Amount Type	2013					
	2013 - Jan	2013 - Feb	2013 - Mar	2013 - Apr	2013 - May	2013 - Jun
Dollars	$35	$35	$35			
Hours	1.0	1.0	1.0			

Reference row available to compare values from previous scenarios

Amount	2013	2014	2015	2016	2017	2018
Type	2013 Total	2014 Total	2015 Total	2016 Total	2017 Total	2018 Total
Dollars	$0	$0	$0	$0	$0	$0
Hours	0.0	0.0	0.0	0.0	0.0	0.0

Current and Multi-Year Forecast Process

2 System Entry

Users will identify changes and reflect labor and other than labor changes

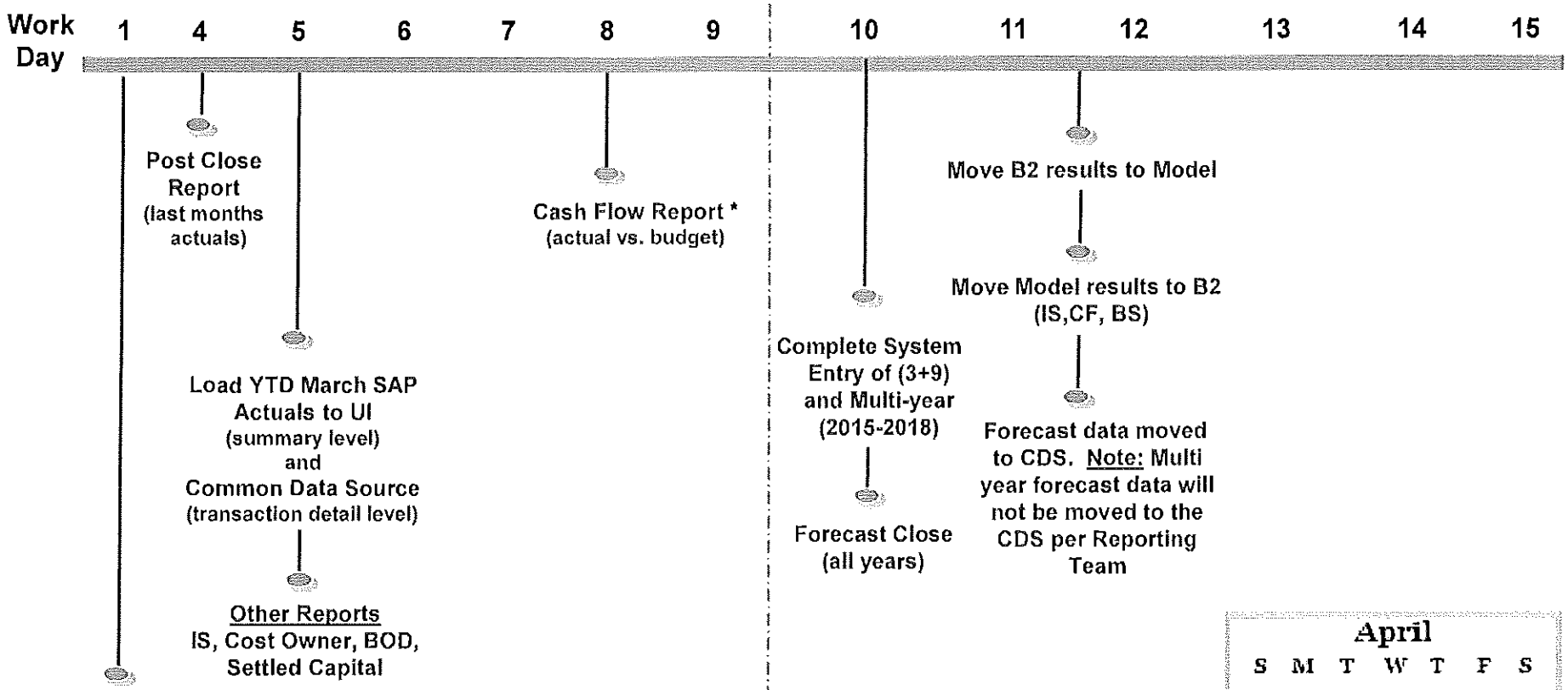


- Employee Labor
  - SAP HR data will be interfaced to UIPlanner initially for calculation of activity prices, but also monthly to reflect employee changes such as pay adjustments, vacation and PAD usage
  - Interface will automatically run the first workday each month
  - Labor balances should be reviewed as part of the forecast process
- Allocate Labor and Non Labor
  - Adjust cost collector dollars/hours for remaining months
- Create/Maintain Budget Group Budget Items (optional)
  - Create new budget groups budget items to capture new cost collector additions
- Project Planning and Tracking
  - Identify new projects
  - Identify project changes and status

Current and Multi-Year Forecast Process

Illustrative

- Schedule included with annual guidelines
- Standard reports will be utilized to manage results



- New scenario created for 3+9. System open for entry
  (scenario can be created in previous month)
- Run applicable interfaces (e.g. monthly HR data)

Specific calendar days will utilize standard reports

- System generated cash flow reports will not be available until BPC go-live 5/9/14. Actual to budget/forecast cash variance reporting will continue to be created using the current process

April

S	M	T	W	T	F	S
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23	24	25	26
27	28	29	30			

- **Multi-Year Plan / Forecast**
  - Performed in conjunction with the annual and monthly forecast process
  - Multi year approach
    - Focus on one year out (year 2) – identification of known key events and business unit initiatives
    - Years 3 - 5 identification of primary business drivers
  - Allow users the ability to develop a detailed forecast or adjust at a summary level
  - Budget close will process all years in scenario

Build and refine forecast data for detailed annual budget
Ability to align earnings and cash projections with long-term strategy

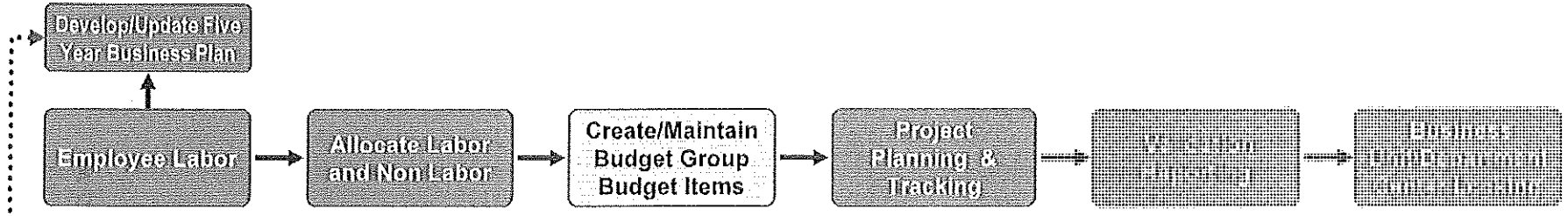
Year 1 (current year)	Year 2	Year 3	Year 4	Year 5
Annual Budget	**Multi-Year Plan / Forecast**			
Current Year Forecast				
• Cost center level details • Identification of specific capital and noncapital projects • Identified strategies • Execute and monitor performance	• Known key events • Business Unit Initiatives	• Primary Business Drivers		
	Key Variable Inputs			
	• *Load* • *Special programs (e.g. forestry, energy efficiency)* • *Transmission* • *Regulatory strategy* • *Power prices* • *Plant outages* • *Fuel*	• *Human Resources special items* • *Tax strategies* • *Treasury activities* • *Accounting treatment* • *Business development strategies*		

Budget, Forecast, Plan Process Summary

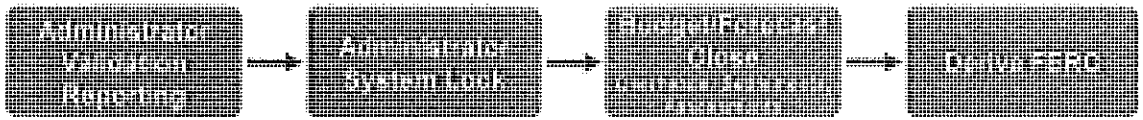
1. Maintain UIPlanner System & Process



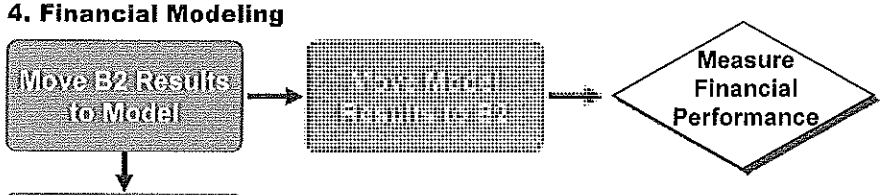
2. System Entry



3. System Administrator Activities

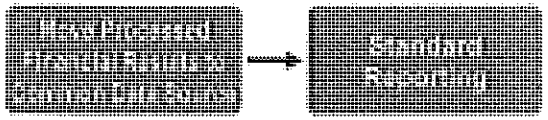


4. Financial Modeling



- *Improve decision making with what-if analysis*
- *Identify and implement financial initiatives and strategic alternatives*
- *Develop internal multi-year financial guidance and targets*

5. Reporting



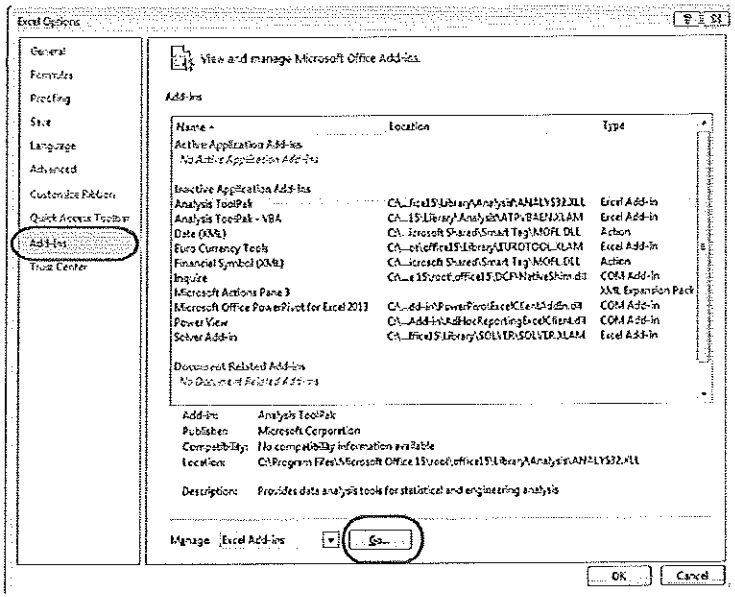
UIPlanner Log In Process

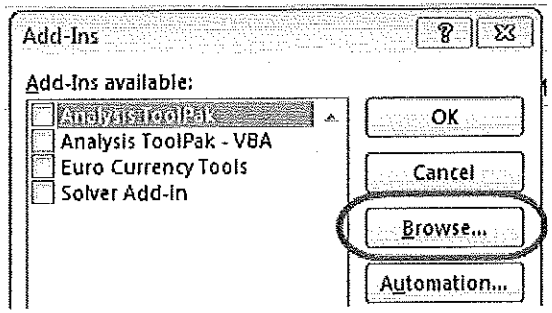
Install Excel Add-Ins

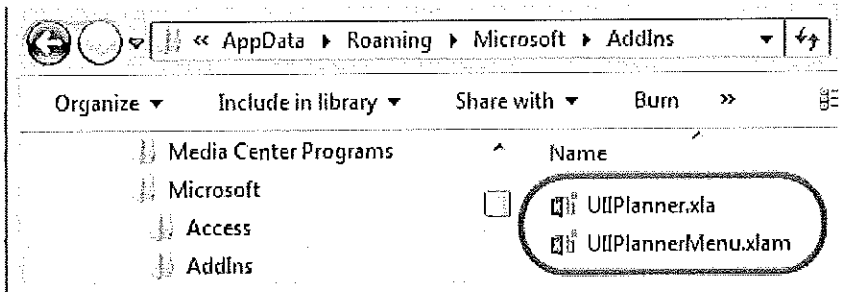
- **UIPlanner Excel Add-Ins are used for Excel upload / download functionality**
- **Add-Ins are User ID and computer specific**
- **Follow these steps to copy the Add-Ins files to your Excel session on the computer you will use to access UI Planner**
  - **Step 1 – Locate the files to be copied**
    - Open Windows Explorer, navigate to the U: shared drive to your appropriate group folder and leave this window open.
      - U:\FE\Competitive - FES\FiT Project\UIPlanner\Excel Add Ins
      - U:\FE\EnerAff\FiT Project\UIPlanner\Excel Add Ins
      - U:\FE\RegEnt\FiT Files\UIPlanner\Excel Add Ins
      - U:\FE\ShrSvc\FiT\UIPlanner\Excel Add Ins
  - **Step 2 – Copy the files from the U drive to your C drive through Excel**
    - Follow the instructions pertaining to your version of Excel (see next slides)
    - Excel will direct you to where the files should be copied
  - **Step 3 – Confirm the Add-In was installed**
    - Follow the instructions pertaining to your version of Excel (see next slides)

Excel Add-Ins – Step 2

- **For Excel version 2010 or 2013**
  1. Open Excel (version 2010 or 2013)
  2. Click File > Options
  3. From the Excel Options window, select **Add Ins** then click **GO**
  4. From the Add Ins pop up, click **Browse**
  5. Excel will take you to the location where the files should be (It will be empty)
  6. Navigate to your Windows Explorer session and copy the two Add-In files
  7. Navigate to your Excel session and paste the two files into the 'AddIns' folder Excel has selected for you

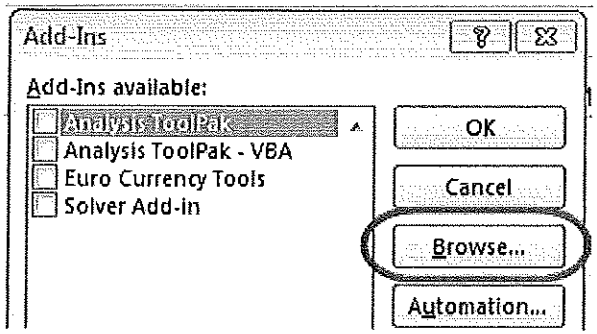


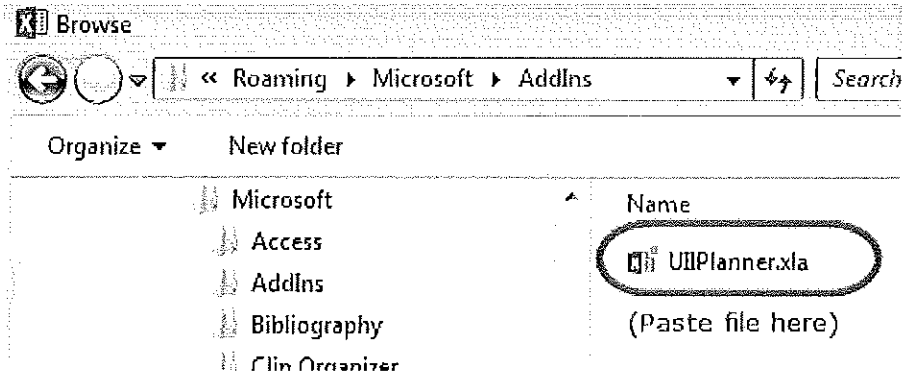




Excel Add-Ins – Step 2 (continued)

- **For Excel version 2003 or 2007**
  1. Open Excel
  2. From the menu bar, select Tools > **Add Ins**
  3. From the Add Ins pop up, click **Browse**
  4. Excel will take you to the location where the files should be (It will be empty)
  5. Navigate to your Windows Explorer session and copy one Add In file UIPlanner.xla
  6. Navigate to your Excel session and paste the file into the 'AddIns' folder Excel has selected for you

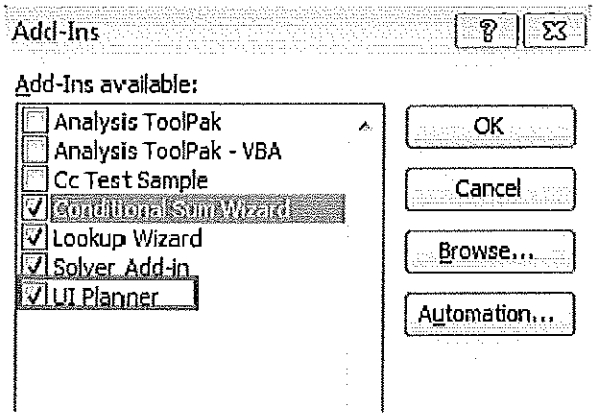




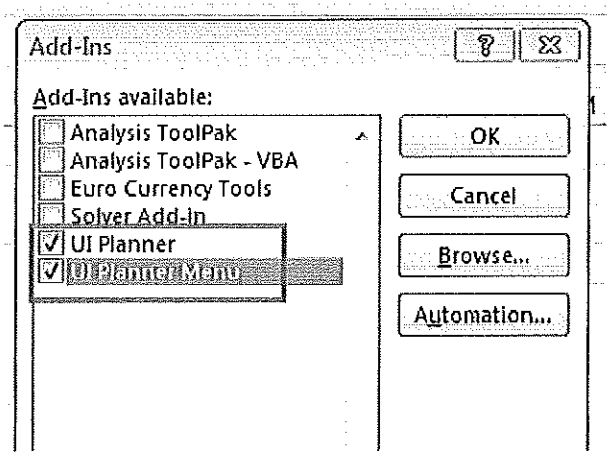
Excel Add-Ins – Step 3

Confirm the Add-In was installed

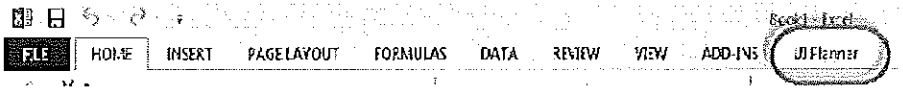
- ***For Excel 2003 or 2007***
  - Click 'Tools' menu
  - Select 'Add-Ins'
  - Confirm 'UI Planner' is checked



- ***For Excel 2010 or 2013***
  - Click File > Options > Add-Ins > GO
  - Confirm 2 UIPlanner Add-In files are checked



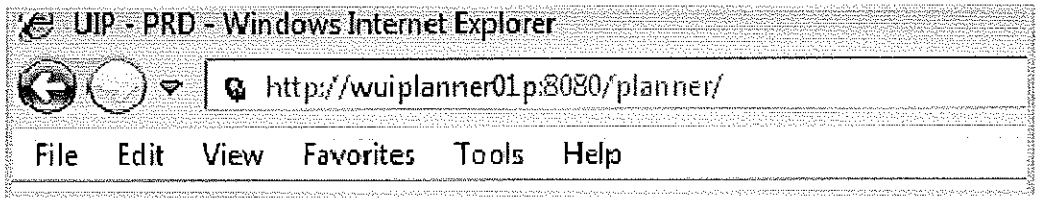
  - New 'UI Planner' Menu option appears

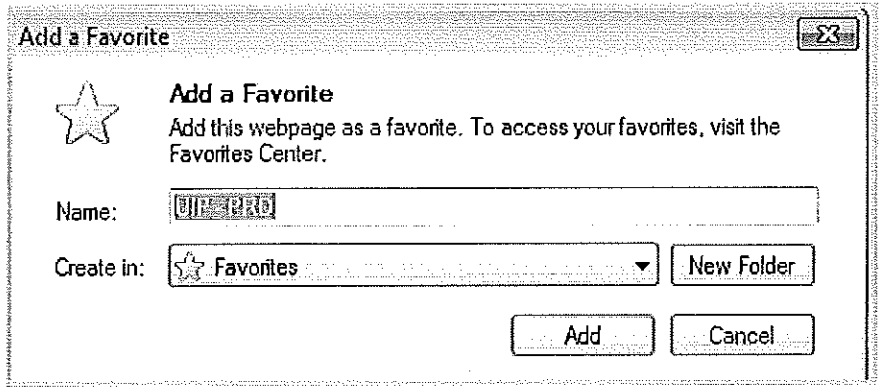


UIPlanner Log In

1. • Enter the link on the browser line
   - http://wuiplanner01d:8080/planner/ - Development
   - http://wuiplanner01t:8080/planner/ - Test
   - http://wuiplanner01p:8080/planner/ - Production

- Add to Favorites

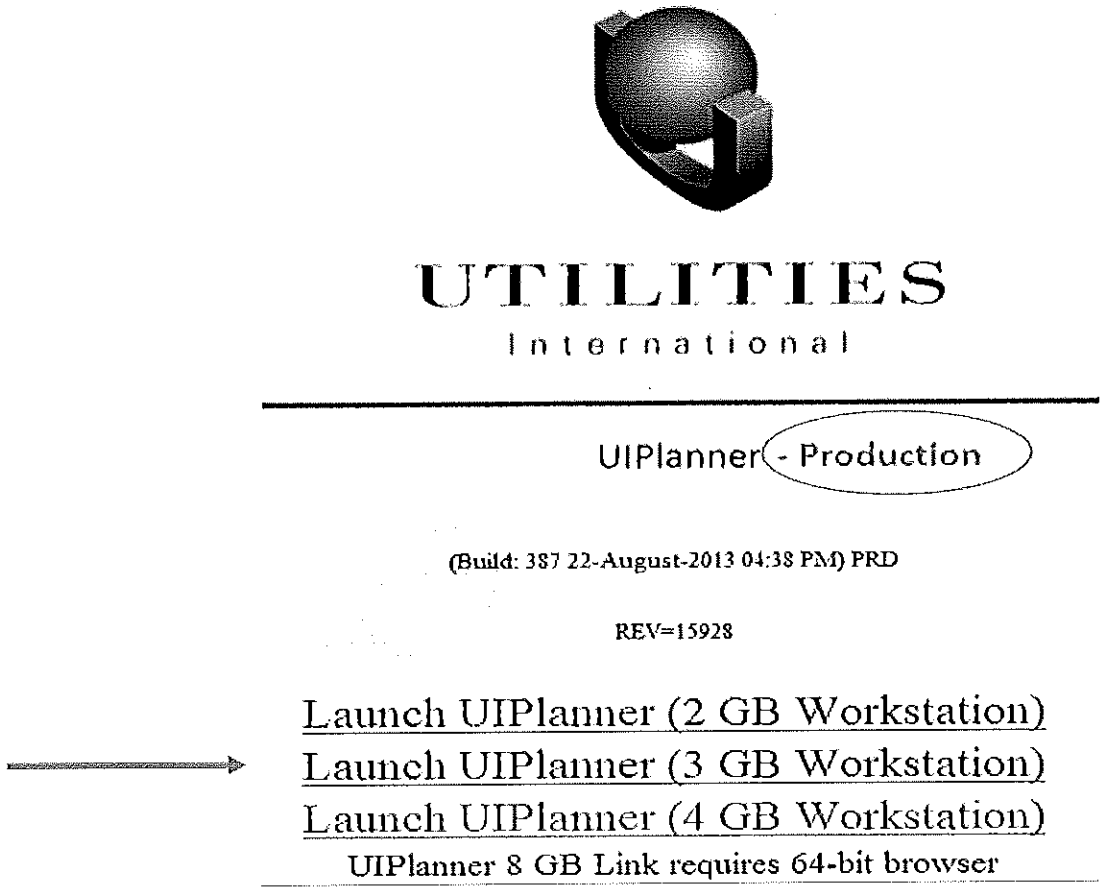




UIPlanner Log In

2

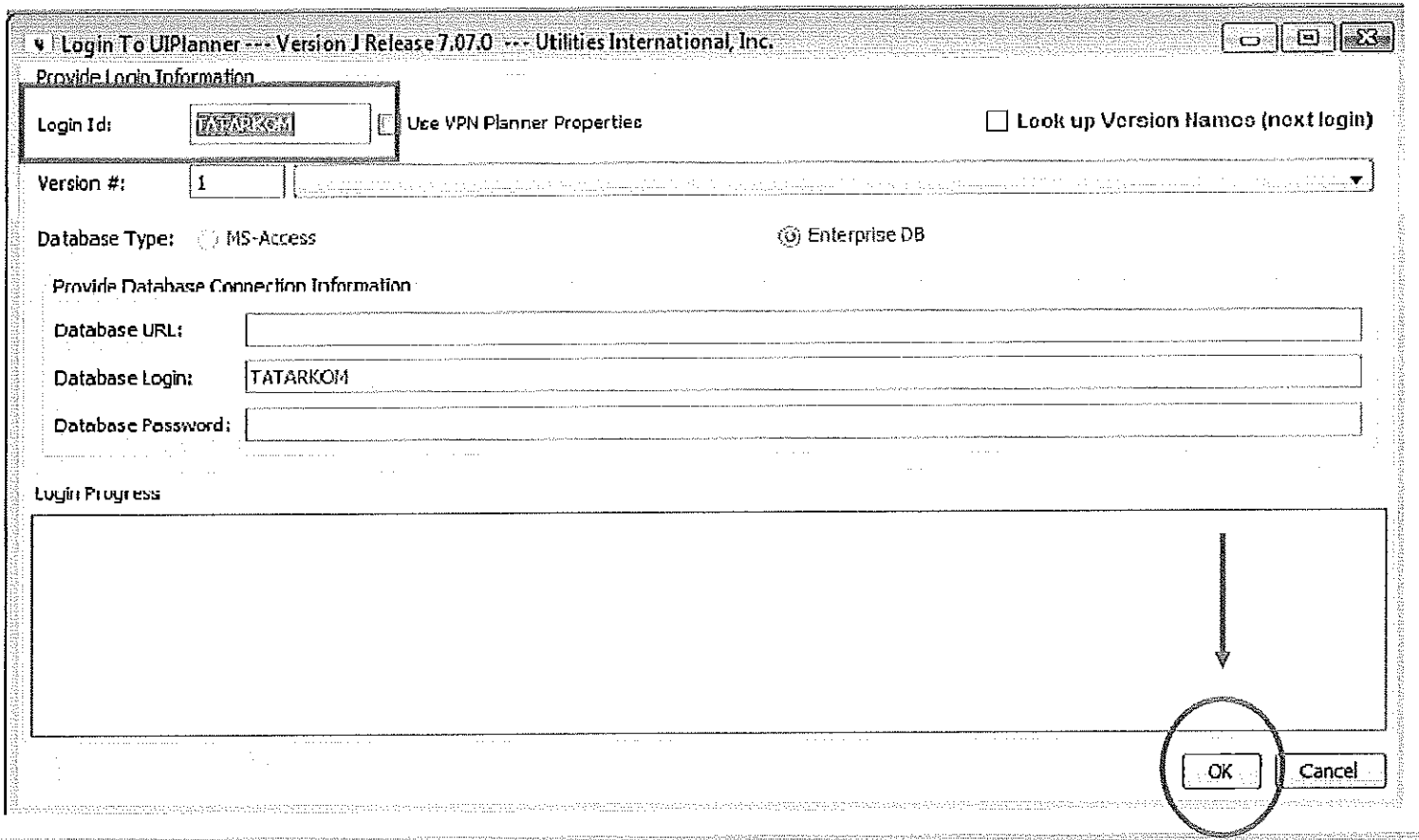
- After entering the link, the UIPlanner software main screen will display
- Click on (3 GB or 4 GB Workstation)



UIPlanner Log In

4

- User Login ID will display
  - UIPlanner has single sign on capability and authenticates on your network login ID
- Click OK



UIPlanner Security

UIPlanner Security

- UIPlanner security will be established using the Financial Accountability Model hierarchy (ZBWCAM0000) and granted at the node level within each business unit/department

- Multiple roles or levels of security will be granted

  - **Budget Security**
    - Controls access to Budget-specific features and data
    - Includes Application Rights, which control access to screens and tools, and Cost Center Rights which limit access to data based on the user's context within a "Center" hierarchy

  - **Model Security**
    - Controls access to create and delete system-wide model related objects (e.g. Entities, Attributes) and administrative tools (e.g. Manage Menus, Archive)

Key UIPlanner Security Roles

- **System Administrator:**
  - Centralized group that will manage and maintain both B2 and Financial Model
  - Individuals will have all rights to system and can perform functions the average user can not, such as: system configuration, bounce server, deploy new releases

- **Budget Administrator**
  - Centralized group that will manage and maintain B2 system
  - Individuals will have rights to system and can perform all system, business and process functions
    Examples include creating budget scenarios, running interfaces, process budget/forecast close, administer security, system admin locking, maintaining datasets, global assumptions, etc.

- **Budget Coordinator**
  - Individuals having rights to their entire business unit or department
  - Access to all user functions such as viewing and validating individual employee labor data, allocating labor and non labor, project planning, create budget group budget items, budget approval/center locking, and publish reports for their respective areas

- **Budget Input**
  - Individuals having rights to either their entire business unit or department or a specific group or center
  - Individuals will be granted access to all basic budget functions but will not be able to view individual employee labor data, create budget group budget items, and center lock

- **Budget View Only**
  - Individuals can only view published results and view reports

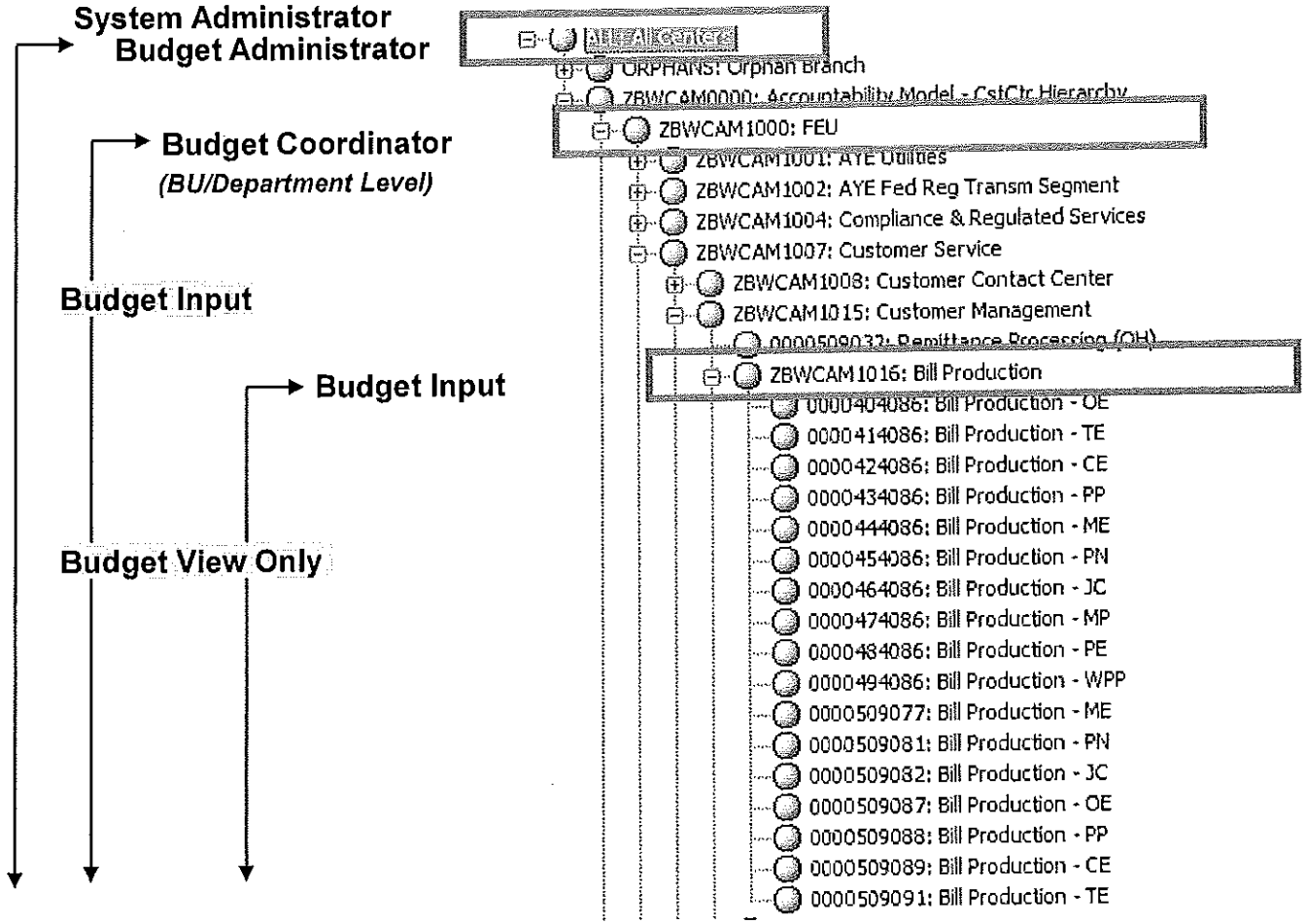
Key UIPlanner Security Roles

- **Budget Coordinator / Model Input**
  - Individuals responsible for both managing labor and other than labor functions for their area and has responsibility for key model inputs

- **Model Administrator**
  - Individuals having rights to the financial model and can perform all model functions

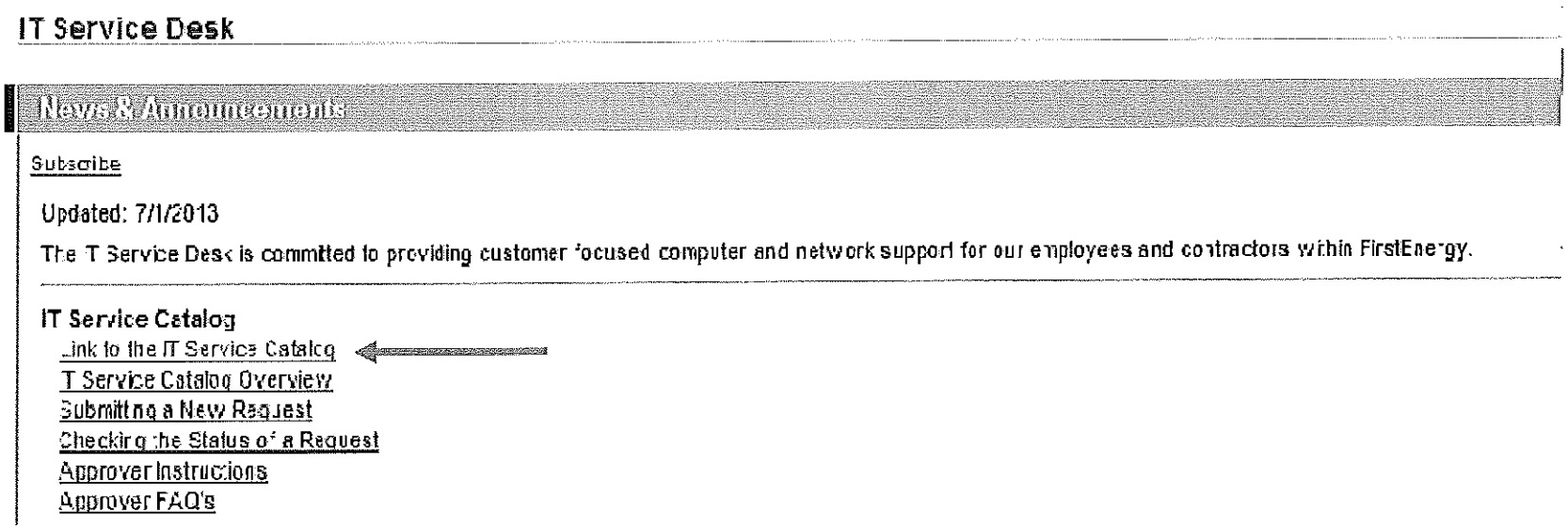
Cost Center Hierarchy and Security

- Budget Security will be established using the Financial Accountability Model hierarchy and granted at the node level within each business unit/department
- Multiple roles or levels of security will be granted



UIPlanner Security Requests

- **UIPlanner Security requests will be managed via the IT Service Catalog**
  - Security requests include: establishing new security, changing security, and removing security for either data collection or financial modeling
  - This process is used for both employees and contractors
- **The IT Service Catalog can be accessed in one of two ways via the portal:**
  1. Path: Services and Support>Work Related>IT Service Desk>Link to the IT Service Catalog
  2. IT Service Catalog can also be accessed by typing 'ITcatalog' into the Internet Explorer Address Bar



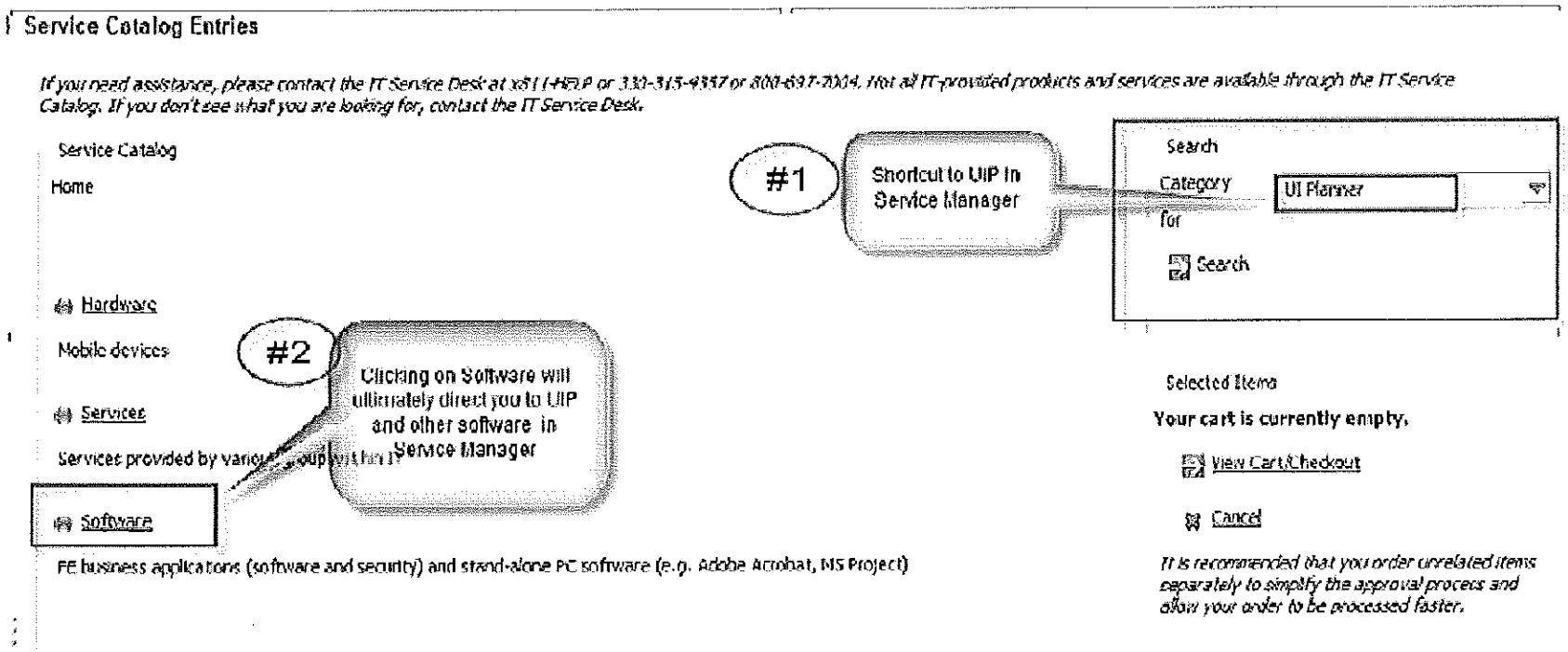
How to Request UIPlanner Security

- **To request UIPlanner security for data collection or financial modeling perform the following processes once in the IT Service Catalog:**
  - Search for UIPlanner by selecting "UIPlanner" in the Category field of the Search (see #1 below)

    OR

    Navigate to

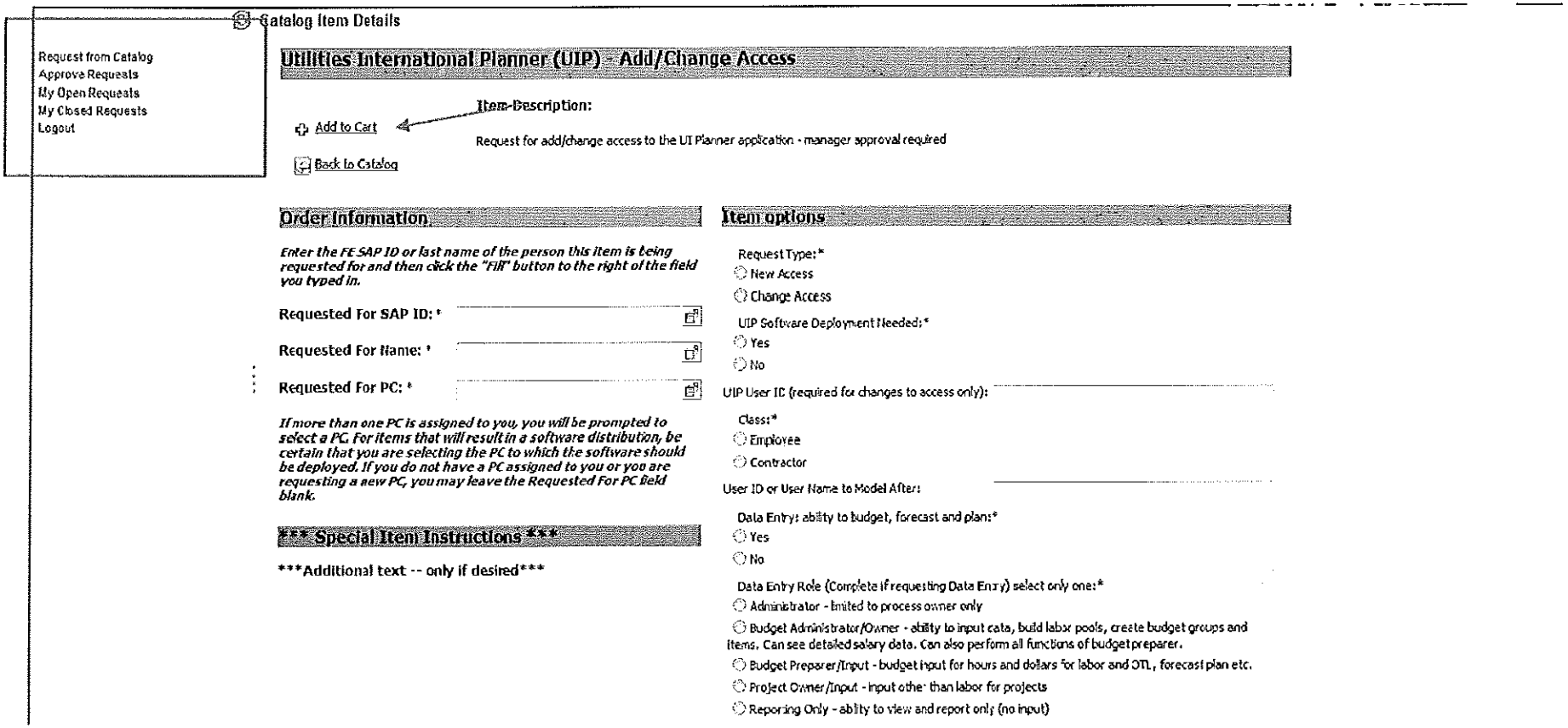
    Software>FE Business Applications>Corporate Business Applications>Finance Business Applications>UIPlanner
  - Select UIPlanner – Add/Change Access (see #2 below)
  - Follow instructions on form
  - For further information on UIPlanner security, refer to the UIPlanner Security Management Policy located at: Portal >Communities> Finance> Policies> FiT



Requesting or Changing User Security

After completing the form

1. Click "add to cart". A message box will appear that it has been added.
2. Click "view cart/checkout" when finished.
3. The request will be routed for approval.
4. To view the status of the request, follow the links on the left of the screen



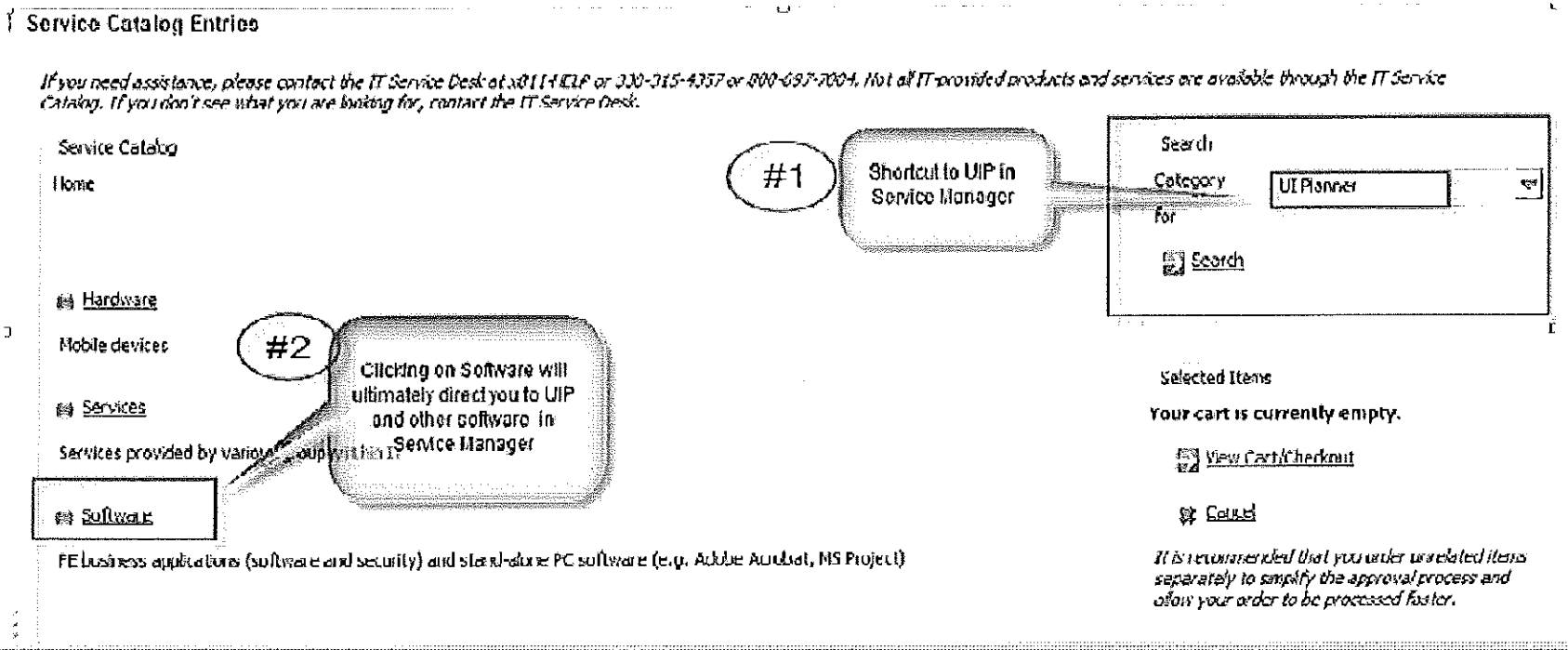
Removing UIPlanner Security

- **To Remove UIPlanner security for data entry and/or financial modeling perform the following process:**
  - Search for UIPlanner by selecting "UIPlanner" in the Category field of the Search (see #1 below)

    OR

    Navigate to

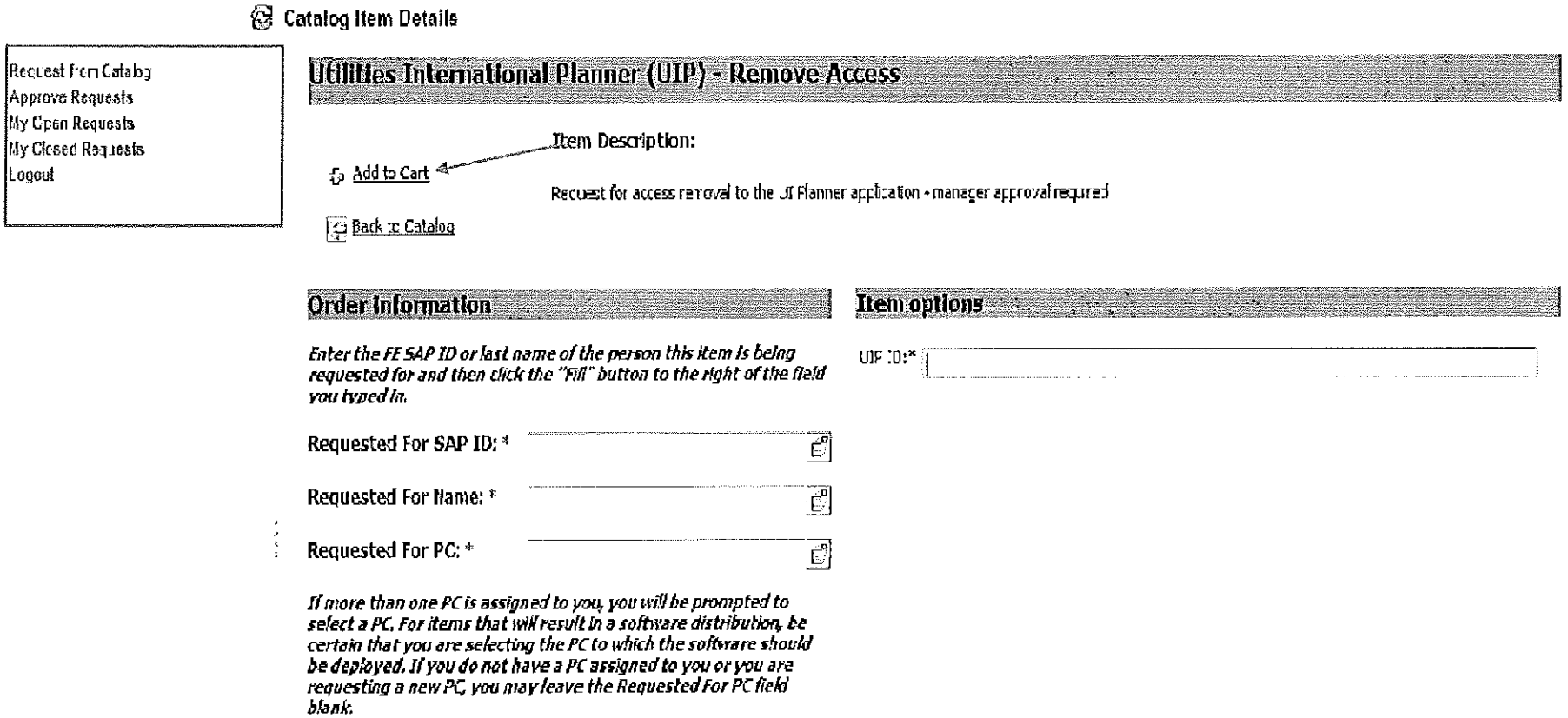
    Software>FE Business Applications>Corporate Business Applications>Finance Business Applications>UIPlanner (see #2 below)
  - Select UIPlanner – Remove Access
  - Follow instructions on form
  - For further information on UIPlanner security, refer to the UIPlanner Security Management Policy located at: Portal >Communities> Finance> Policies> FiT



Removing UIPlanner Security

After completing the form

1. Click "add to cart"
2. The request will be routed for approval.
3. To view the status of the request, follow the links on the left of the screen



Obtaining Help

- **IT Service Catalog help is available on the on the IT Service Desk Portal page as well as contacting the IT Service Desk**

IT Service Desk

News & Announcements

Subscribe

Updated: 7/1/2013

The IT Service Desk is committed to providing customer focused computer and network support for our employees and contractors within FirstEnergy.

New USB Removable Device Policy

Please go to the Cyber Security Policies page to review the new policy listed as IT-SEC-POL-013 Computer and Network Usage - 08.15.13.

USB Removable Media Device Restrictions FAQs

IT Service Catalog
- Link to the IT Service Catalog
- IT Service Catalog Overview
- Submitting a New Request
- Checking the Status of a Request
- Approver Instructions
- Approver FAQ's

Contact the IT Service Desk by phone for immediate assistance, or send an email to FE Help Desk and your request will be addressed as quickly as

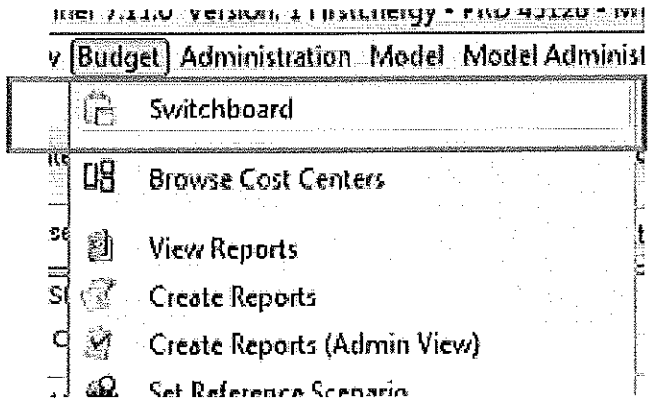
Internal	External	FAX
811-HELP 811-4357	330-315-4357 800-697-7004	801-6867 330-374-6867

- **For more information on requesting access refer to policies on the portal at: Communities > Finance > Polices & Procedures > FiT**
  - **UIPlanner – Security Management**

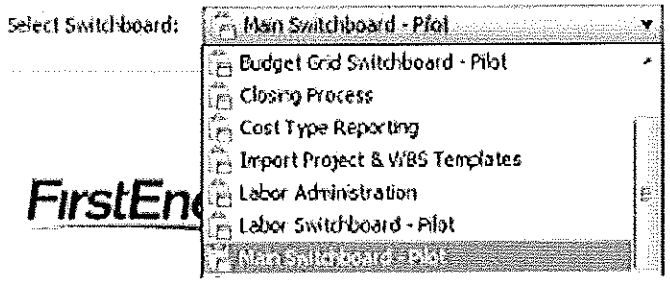
Navigating in UIPlanner — Browse Cost Center

Navigating in UIPlanner

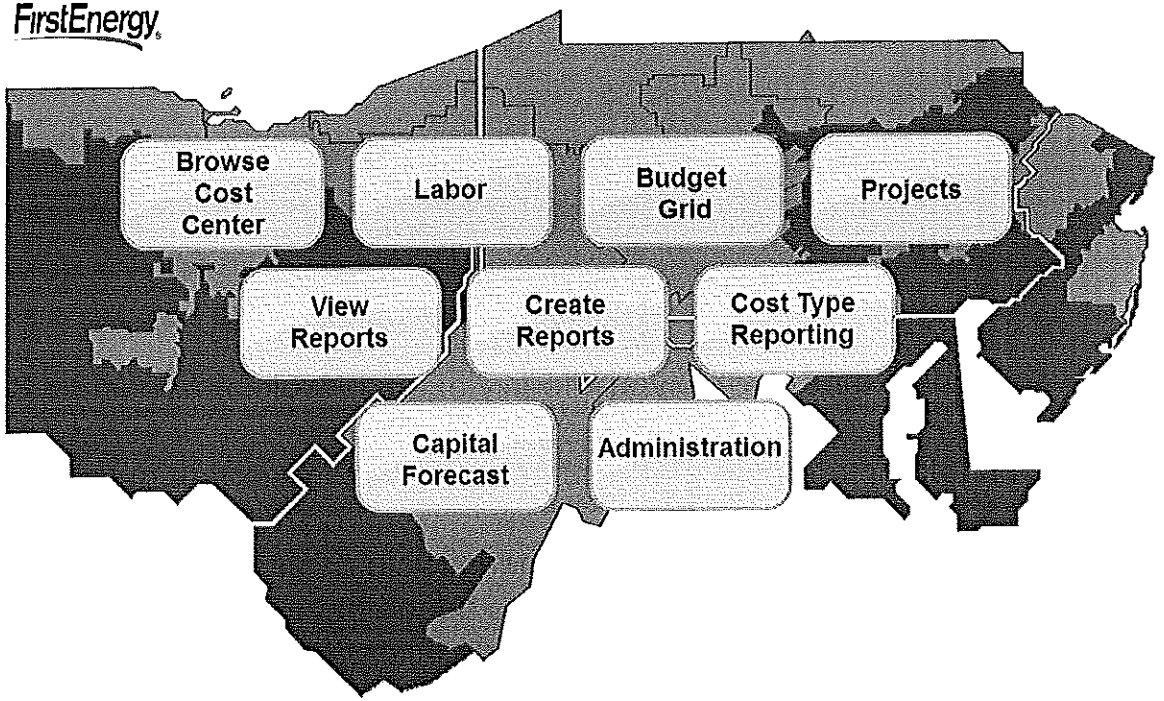
1. • Select Budget
   • Click Switchboard



2. • Select Main Switchboard-Pilot



- Switchboards allow users to visually navigate through various screens
- User can map processes and features to a diagram created in Power Point or Visio
- Hot-spotted areas on a switchboard can open menu items, run reports, open files, and open other switchboards
- Switchboards will be maintained by the System Administrator

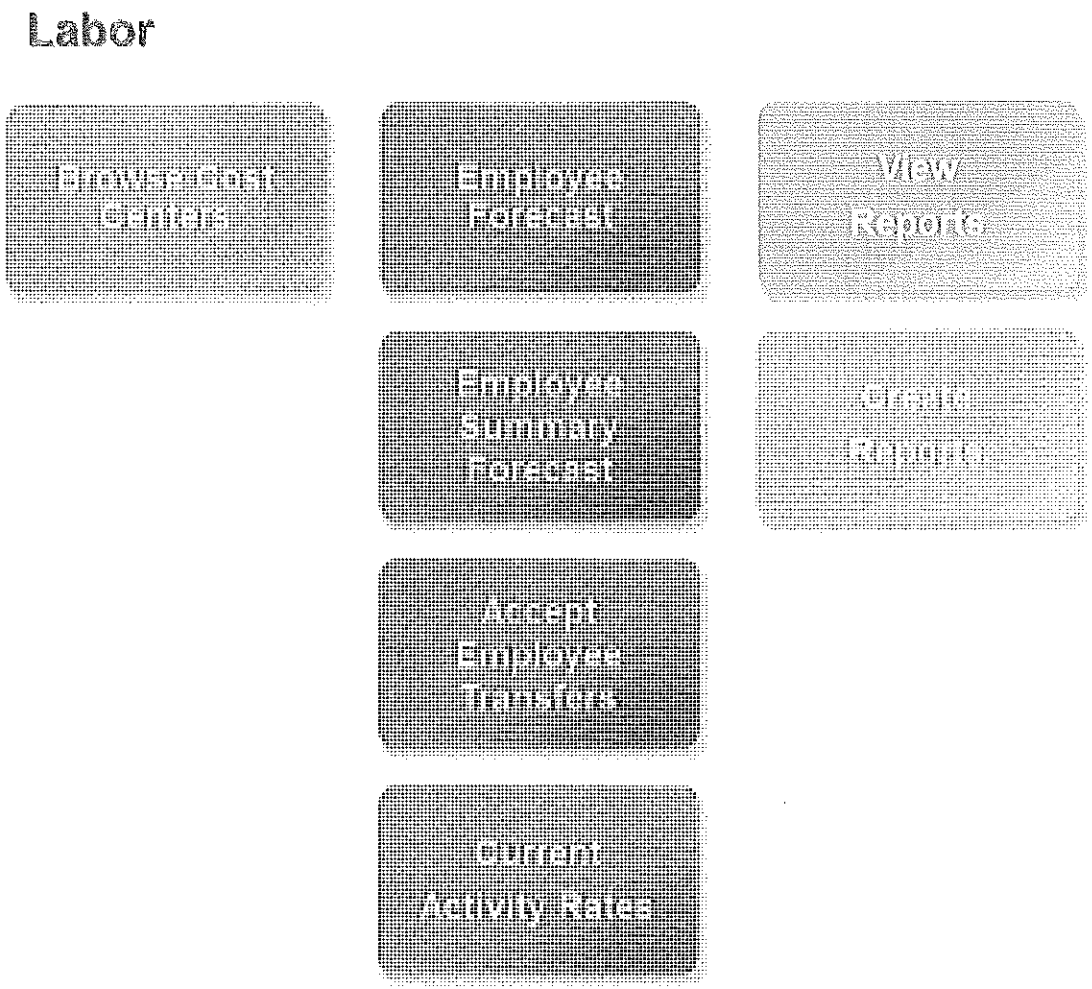


Navigating in UIPlanner

Secondary switchboards exist for the following screens/activities:

- Labor
- Budget Grid
- Projects
- Import Projects
- Cost Type Reporting
- Capital Forecast
- Administration
- Labor Administration

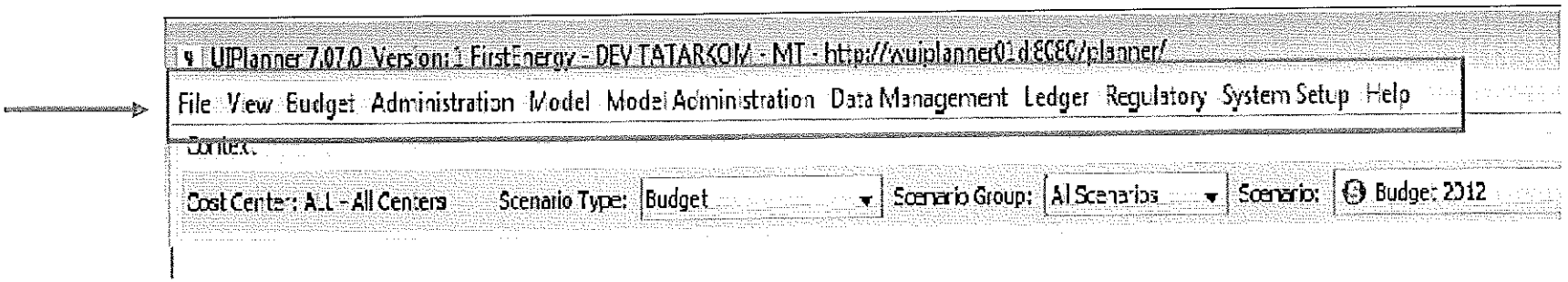
Example of Labor switchboard:



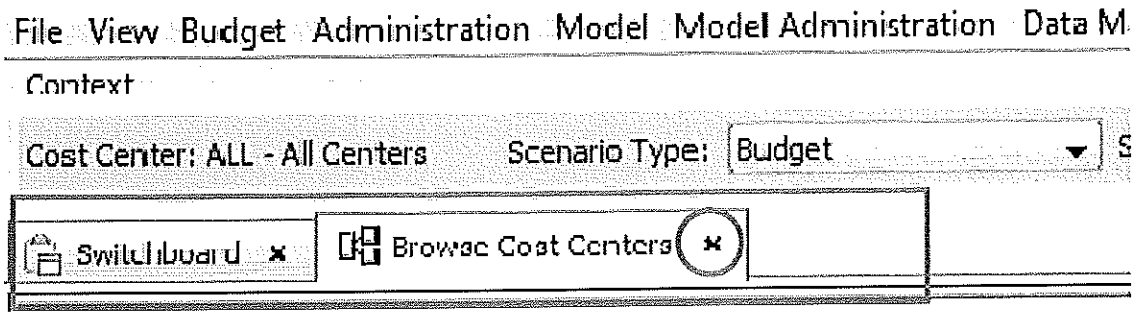
Navigating In UIPlanner

3

- Once logged into UIPlanner, menu options will appear across the screen
- Depending on your security, certain menu items may not be available



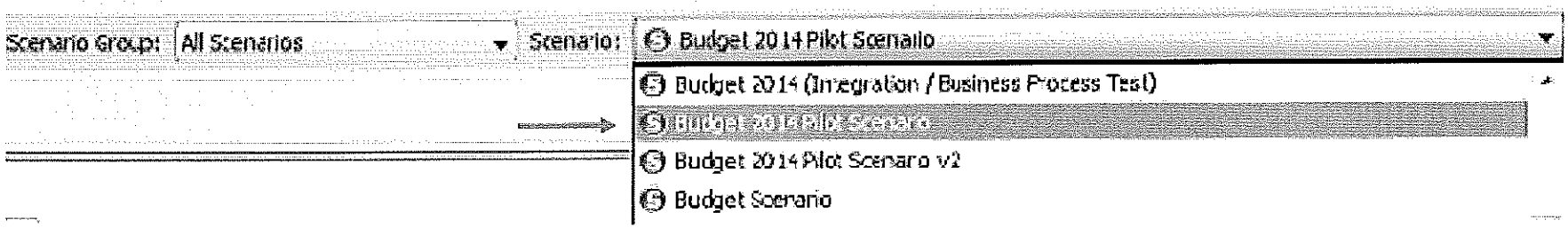
- As menu items are opened, the tab for each menu item will stack across the screen
- Menu items can be closed by clicking the X



Navigating in UIPlanner

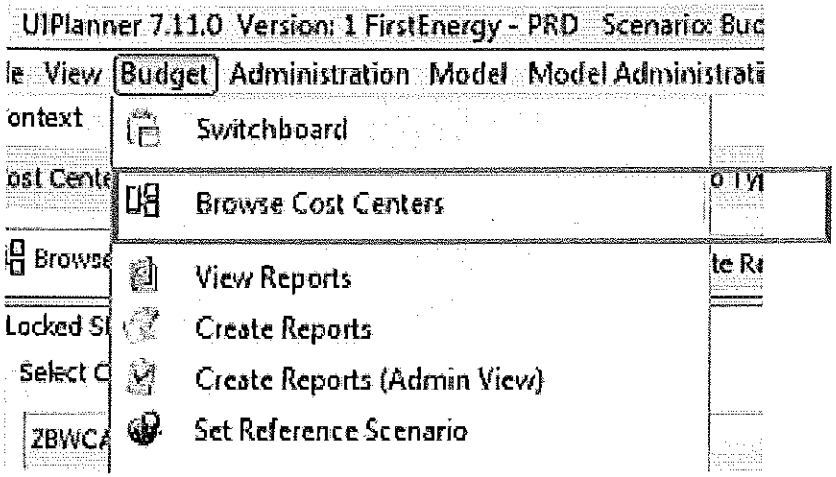
4

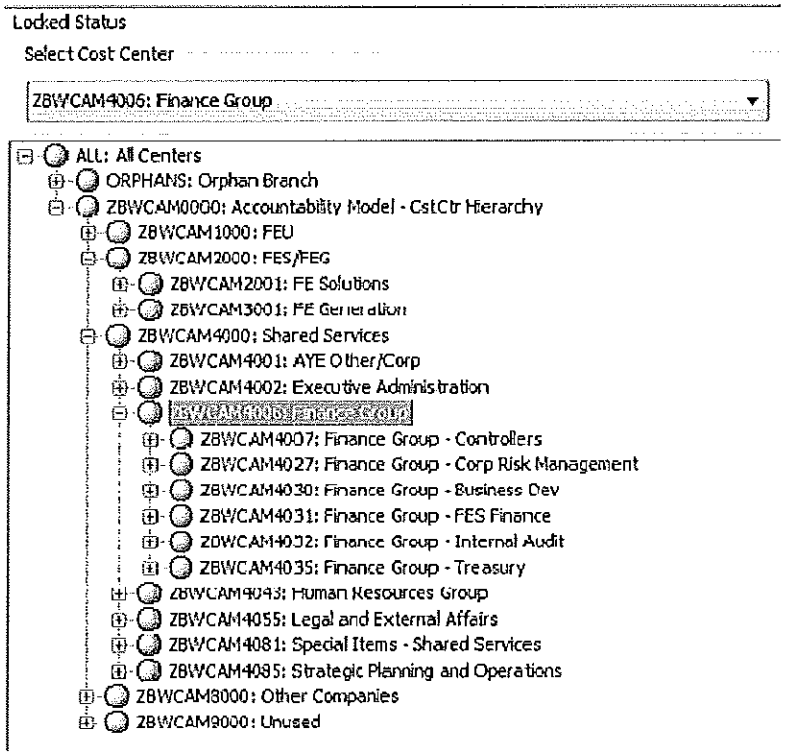
- UIPlanner categories determine the environment to administer the budget, forecast and plan
  - Cost Center: Displays the Cost Center or Cost Center group level selected
  - Scenario Type: Budget or Model
    - Select Budget
  - Scenario Group: Grouping of like scenarios for either Budget or Model
    - Select All Scenarios
  - Scenario: Various iterations and versions of the budget, forecast and plan such as the 3+9, 2013 annual budget, etc. Scenarios will be available within the Scenario drop down box. Scenarios will be created and managed in B2
    - Select Budget 2014 Pilot Scenario



Browse Cost Center Overview

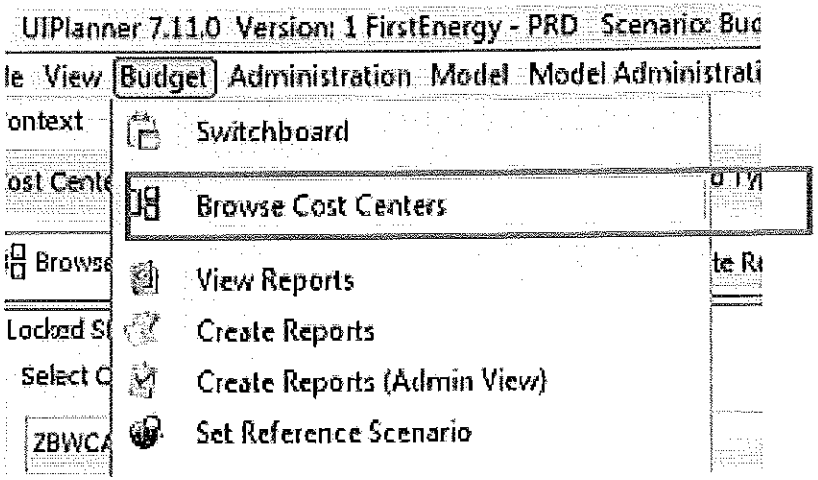
- The Browse Cost Centers function is used throughout UIPlanner to view data for budget, forecast and plan activities
- The Select Center screen is used to select a cost center or department, manage status and monitor changes within UIPlanner
- The Cost Center or Cost Center node selected is carried forward as a filter on department to all budget screens





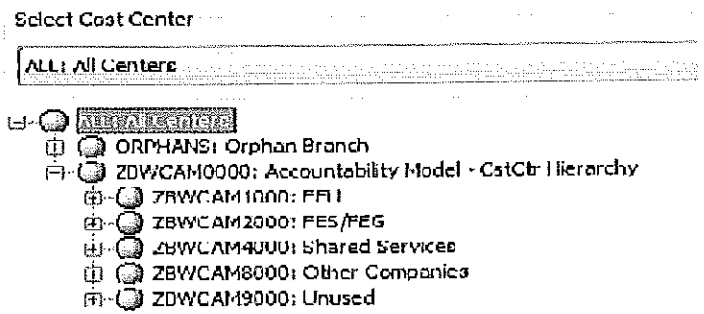
Browse Cost Center

5 • Select **Budget**
• Click **Browse Cost Centers**

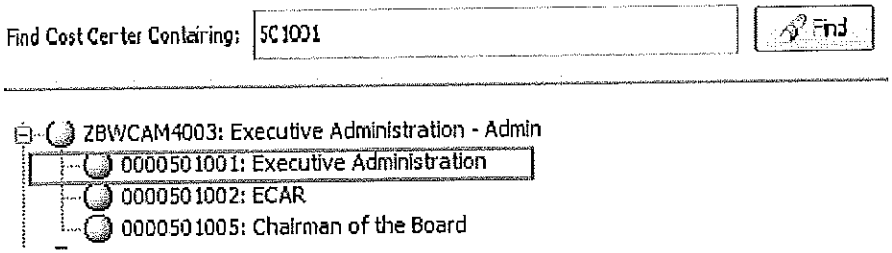


- The Finanical Accountability Model hierarchy is available in UIPlanner and SAP
  - SAP transaction KSH3 – ZBWCAM0000
- Hierarchy is based on cost ownership
- The responsible cost center hierarchy will no longer be available starting 2014

6 • Expand Hierarchy by clicking ⊕

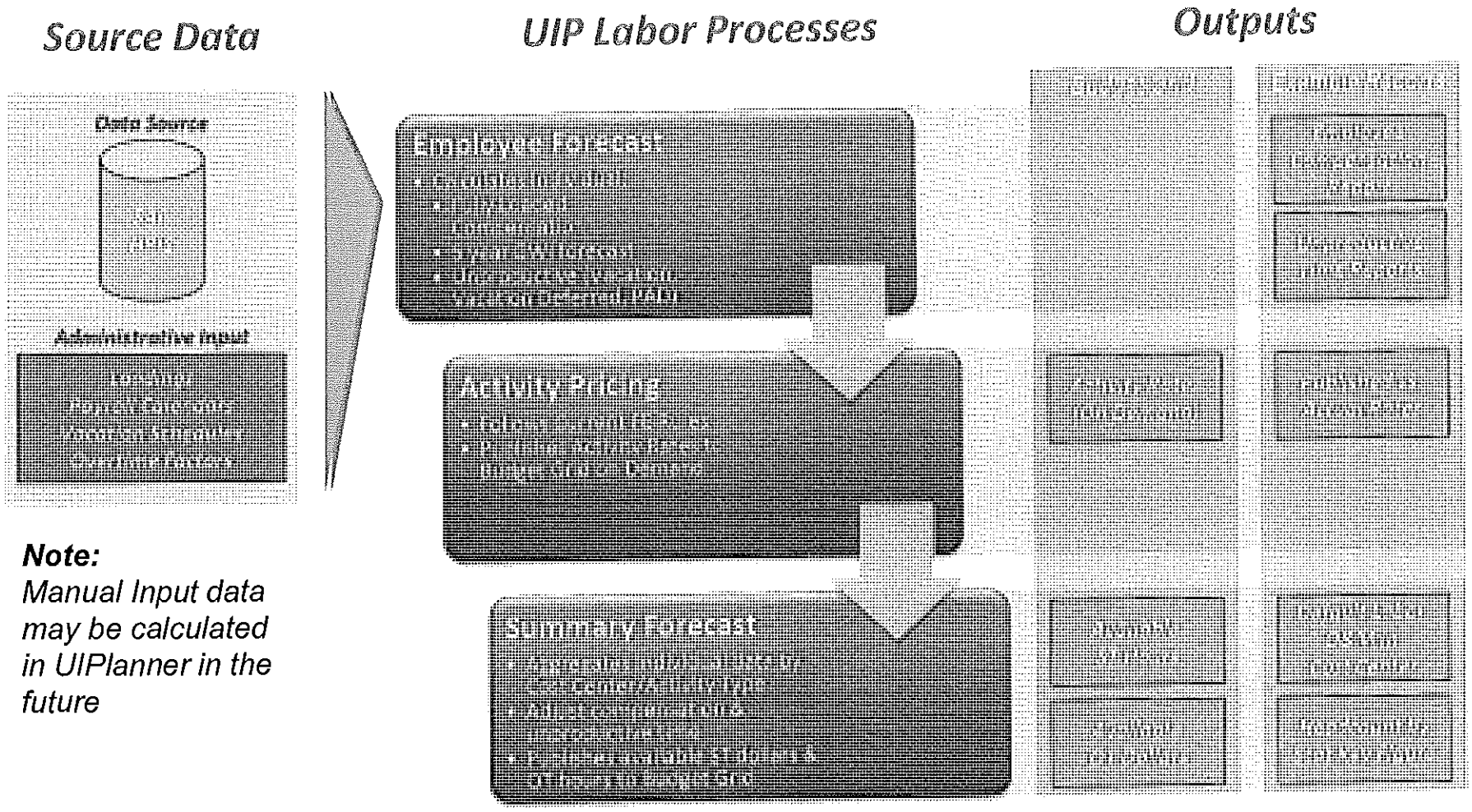


7 • Search Cost Centers in the Hierarchy
• Enter Cost Center or Cost Center description and Click **Find**



Labor Overview

UIPlanner Labor Schematic



Note:
Manual Input data may be calculated in UIPlanner in the future

The new Labor process ensures that activity rates will be available prior to the budget process while enhancing data security and transparency

System Entry - Budget Grid Functions

Budget Grid Overview

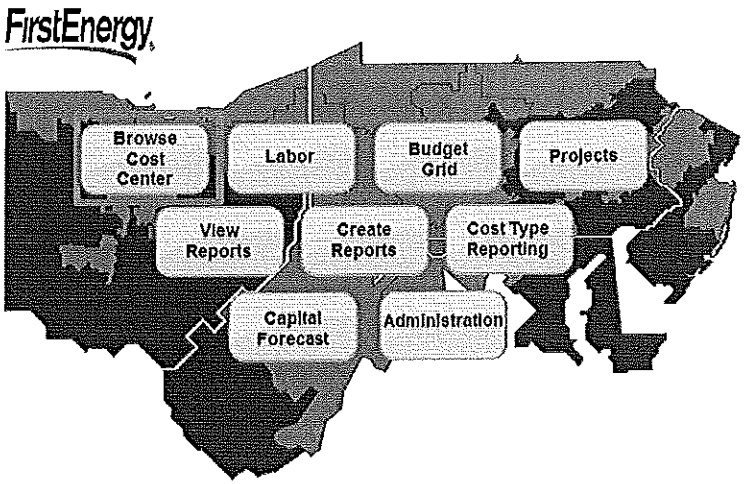
- The Budget Grid is where users enter their Labor and Other-Than-Labor (OTL) budget, forecast, and plan data by the various cost collectors.
- Used only for ALLOCATING hours and dollars --- use "View Reports" to see complete Cost Center view
- Specific budget grid fields comprise the code block combinations necessary to validate system entry

Budget Grid Data Fields

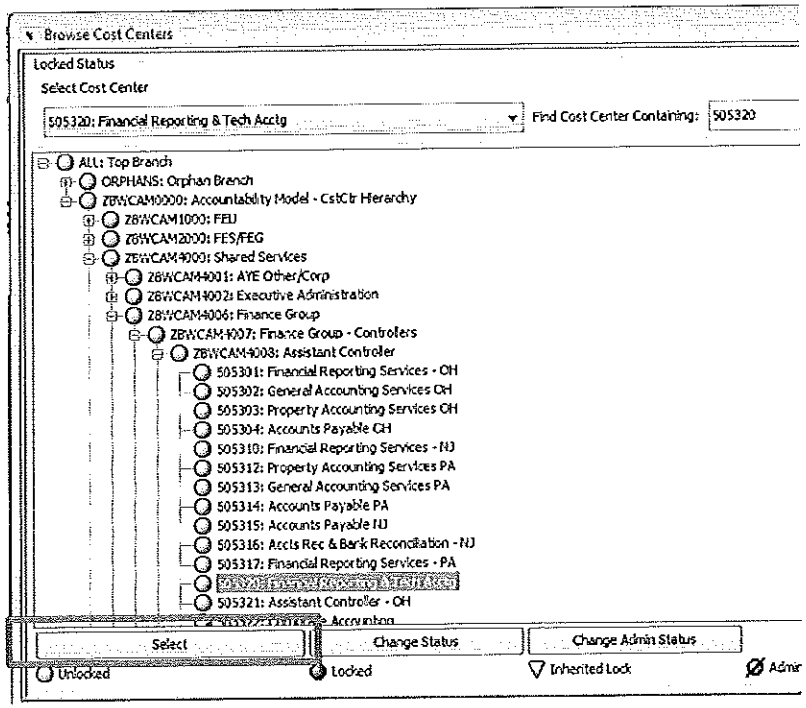
Field	Input vs. Derived	Notes
Cost Source	Input	Cost Source is the Cost Center where employee labor resides. Available Cost Centers will be limited based on user security
Cost Owner	Input	Cost collector owner. When budgeting Labor, this will be the Cost Center being billed for the Labor. When budgeting OTL, Cost Owner and Cost Source will be the same
Cost Collector Type	Input	Types : Cost Center, Internal Orders and WBS
Planning Project	Input	Project Definition of either SAP WBS or the UI Planning Project being budgeted
Planning WBS Element	Input	SAP WBS Elements or the UI Planning Project Elements
Internal Order	Input	Valid and budgetable internal orders
Activity Type	Input	Required only for Labor. Should be set to 'OTL' when budgeting OTL.
Cost Element	Input	Valid and budgetable cost elements
Budget Group	Input	Allows user to apply more detail to the budget. Budget Groups might include Travel or Office Supplies
Budget Item	Input	Allows user to apply more detail to the budget. Budget Items might include Airfare, Hotel and Meals for the Budget Group of Travel.
Comment	Input	Text field. Used for additional notes
Input Type	Derived	Hours if Labor and Dollars if OTL

Budget Grid Startup

1. Defining a Context Cost Center
   - Open the **FE Main Switchboard**
   - Click on **Browse Cost Center**

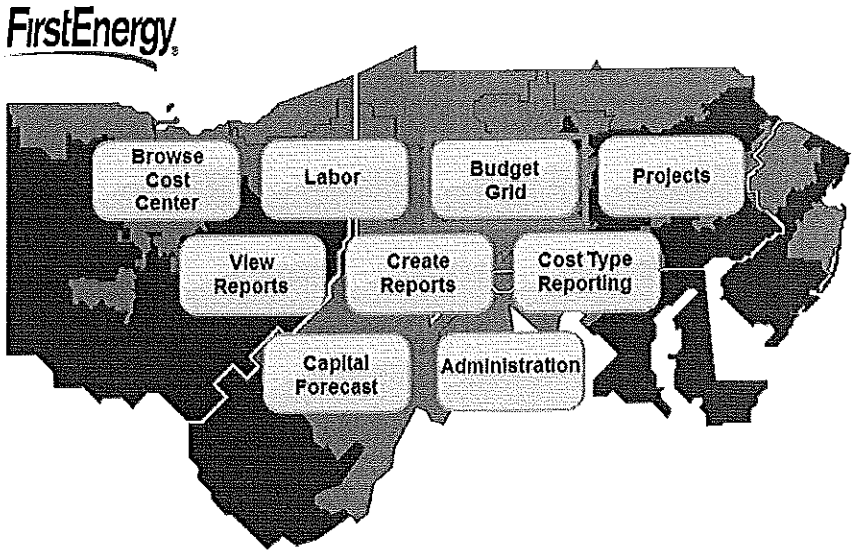


2. • Select a Cost Center (either double-click on or highlight a Cost Center and click the **Select** button at the bottom of screen)

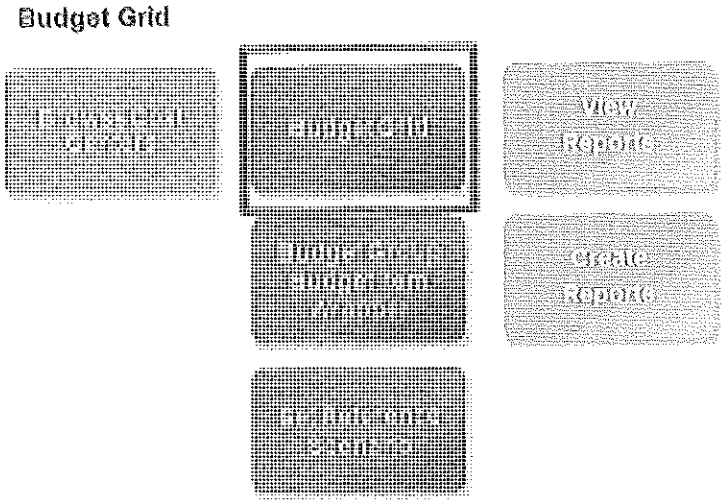


3 Opening the Budget Grid

- Open the **FE Main Switchboard**
- Click on **Budget Grid**

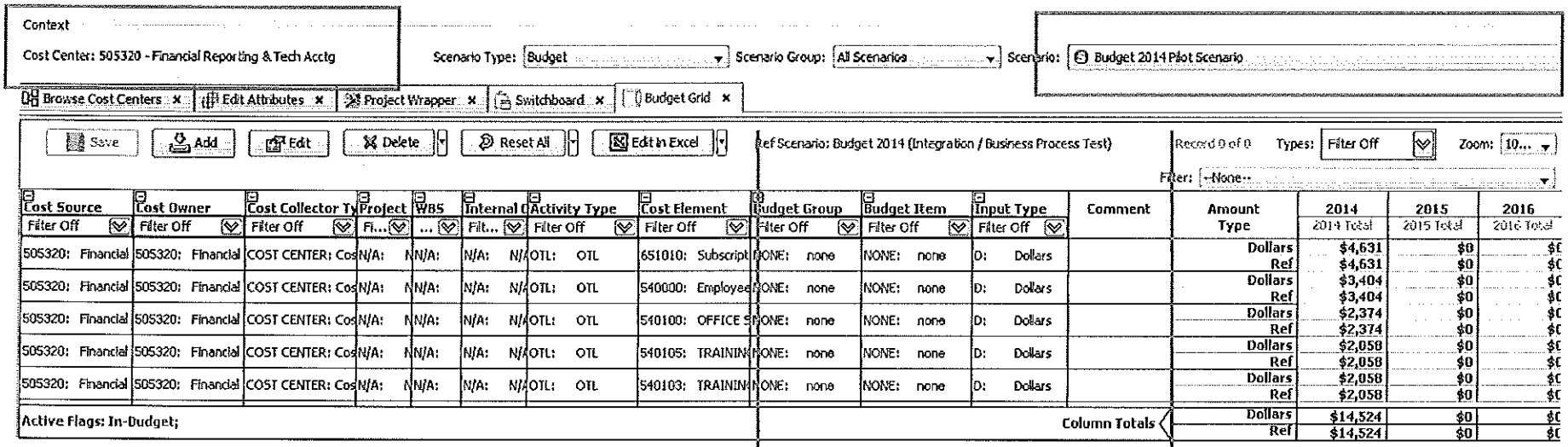


4 • Click **Budget Grid**



Budget Grid Layout Overview

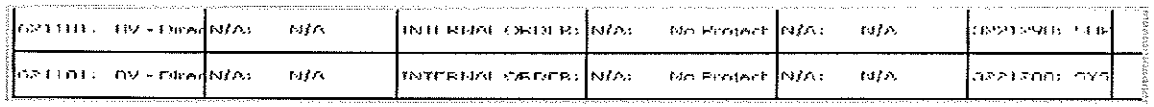
- The Budget Grid consists of required and optional entries
- User can customize grid and maintain user preferences
- Attributes are listed on the left hand side (Accounting) of the Grid
- Data entry takes place on the right hand side of the Grid



Codeblock combinations align with SAP actuals

User defined fields to facilitate budget, forecast, plan preparation and approvals

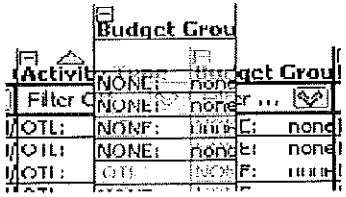
Rows displayed in red denote invalid combinations. Would occur if system validations were changed. User will not be able to enter invalid codeblock

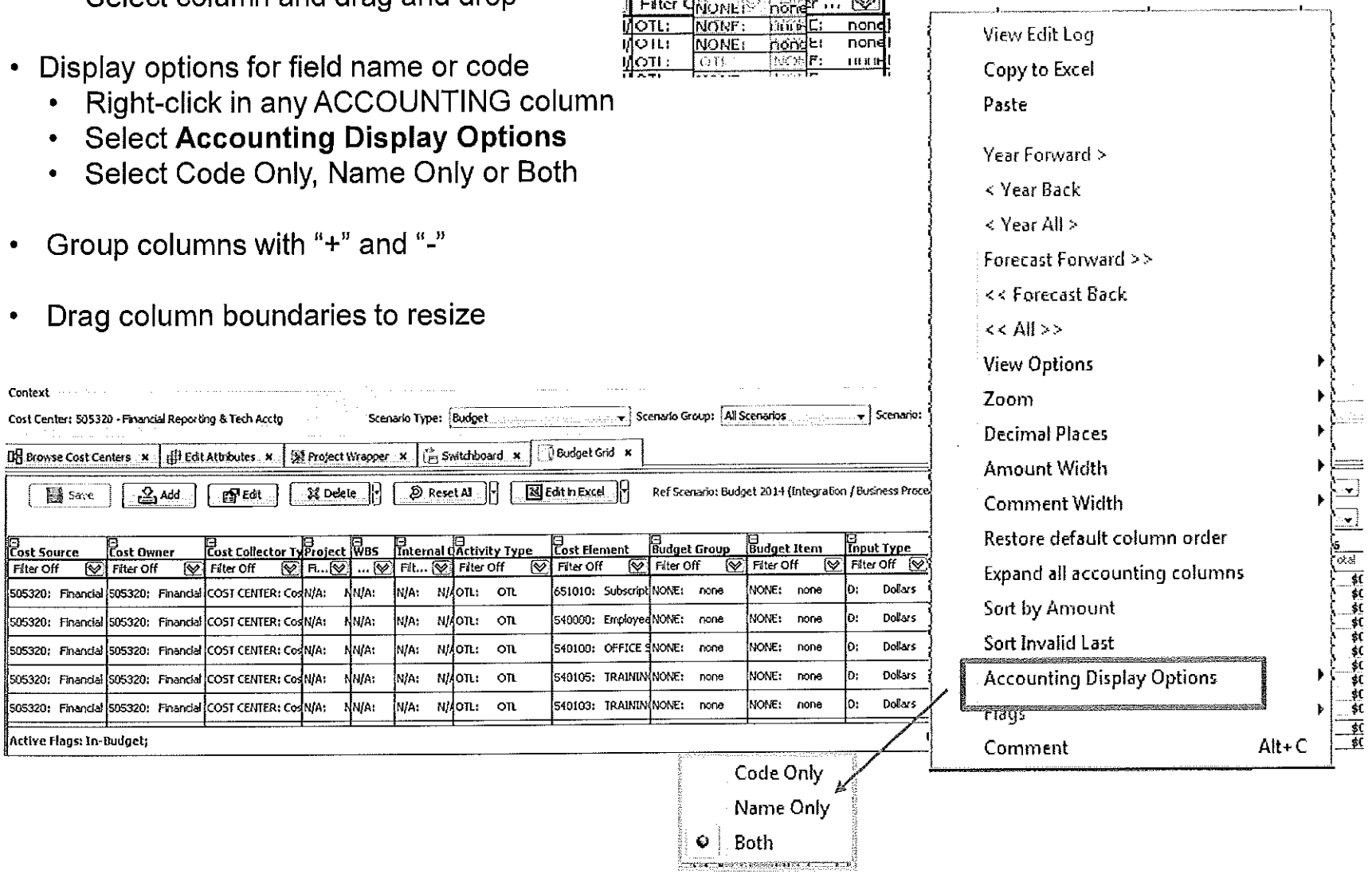


Budget Grid Functions - Display Options

5

- Column ordering
  - Select column and drag and drop
- Display options for field name or code
  - Right-click in any ACCOUNTING column
  - Select **Accounting Display Options**
  - Select Code Only, Name Only or Both
- Group columns with "+" and "-"
- Drag column boundaries to resize

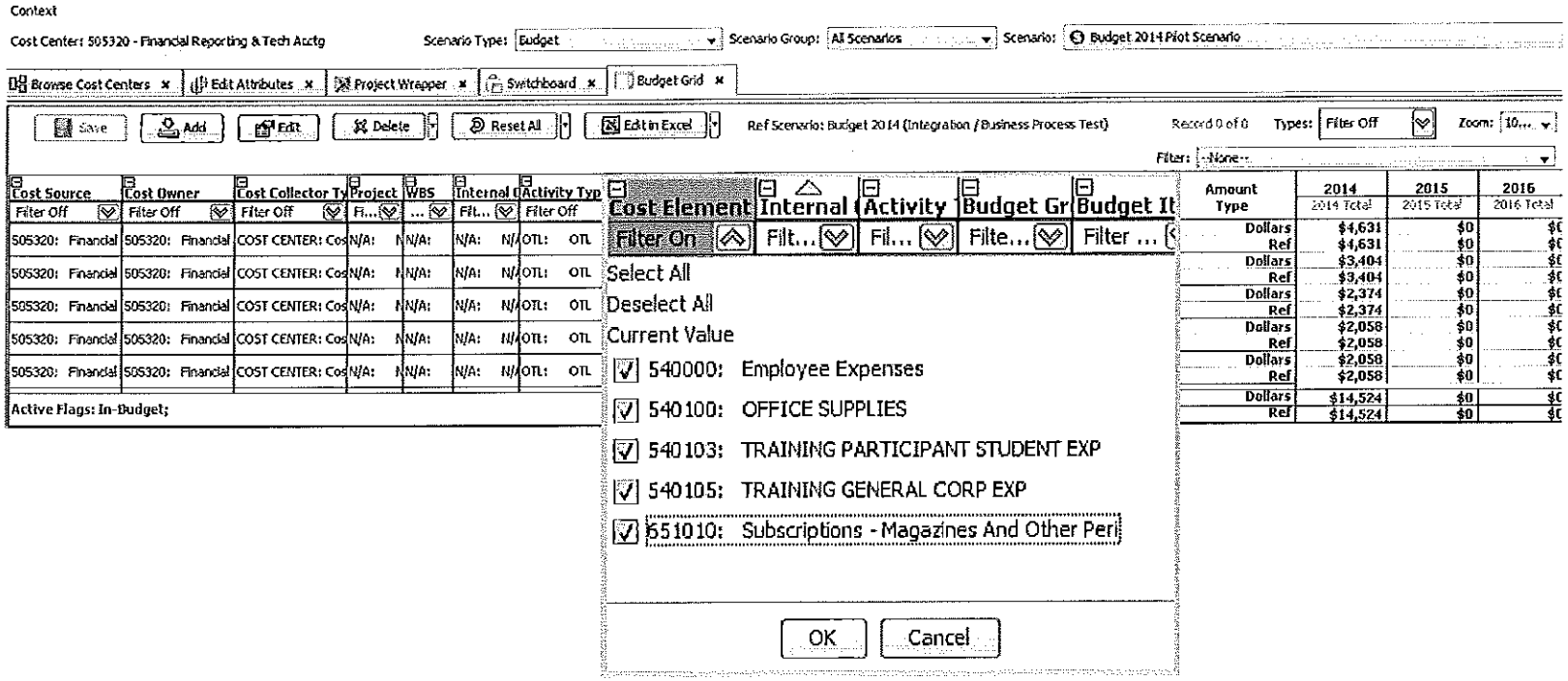




Budget Grid Functions - Filters

6

- Column filtering (e.g. cost element, activity type, etc)
  - All columns have filtering available
  - Select a column to filter
  - Click on filter (column heading turns red when filter is on)
  - Drop down available to select options



Budget Grid Functions - Data Display

- Monthly or annual view of data
  - Click on the year header to toggle between monthly and annual data

Context

Cost Center: 505320 - Financial Reporting & Tech Acctg Scenario Type: Budget Scenario Group: All Scenarios Scenario: Budget 2014 Pilot Scenario

Browse Cost Centers | Edit Attributes | Project Wrapper | Switchboard | Budget Grid

Save | Add | Edit | Delete | Reset All | Edit in Excel Ref Scenario: Budget 2014 (Integration / Business Process Test) Record 0 of 0 Types: Filter Off Zoom: 10... Filter: --None--

Cost Source	Cost Owner	Cost Collector Ty	Project	WBS	Inte	Comment	Amount Type	2014 2014 Total	2015 2015 Total	2016 2016 Total	2017 2017 Total	2018 2018 Total
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$4,631	$0	$0	$0	$0
							Ref	$4,631	$0	$0	$0	$0
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$3,404	$0	$0	$0	$0
							Ref	$3,404	$0	$0	$0	$0
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$2,374	$0	$0	$0	$0
							Ref	$2,374	$0	$0	$0	$0
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$2,058	$0	$0	$0	$0
							Ref	$2,058	$0	$0	$0	$0
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$2,058	$0	$0	$0	$0
							Ref	$2,058	$0	$0	$0	$0
Active Flags: In-Budget;						Column Totals	Dollars	$14,524	$0	$0	$0	$0
							Ref	$14,524	$0	$0	$0	$0

Context

Cost Center: 505320 - Financial Reporting & Tech Acctg Scenario Type: Budget Scenario Group: All Scenarios Scenario: Budget 2014 Pilot Scenario

Browse Cost Centers | Edit Attributes | Project Wrapper | Switchboard | Budget Grid

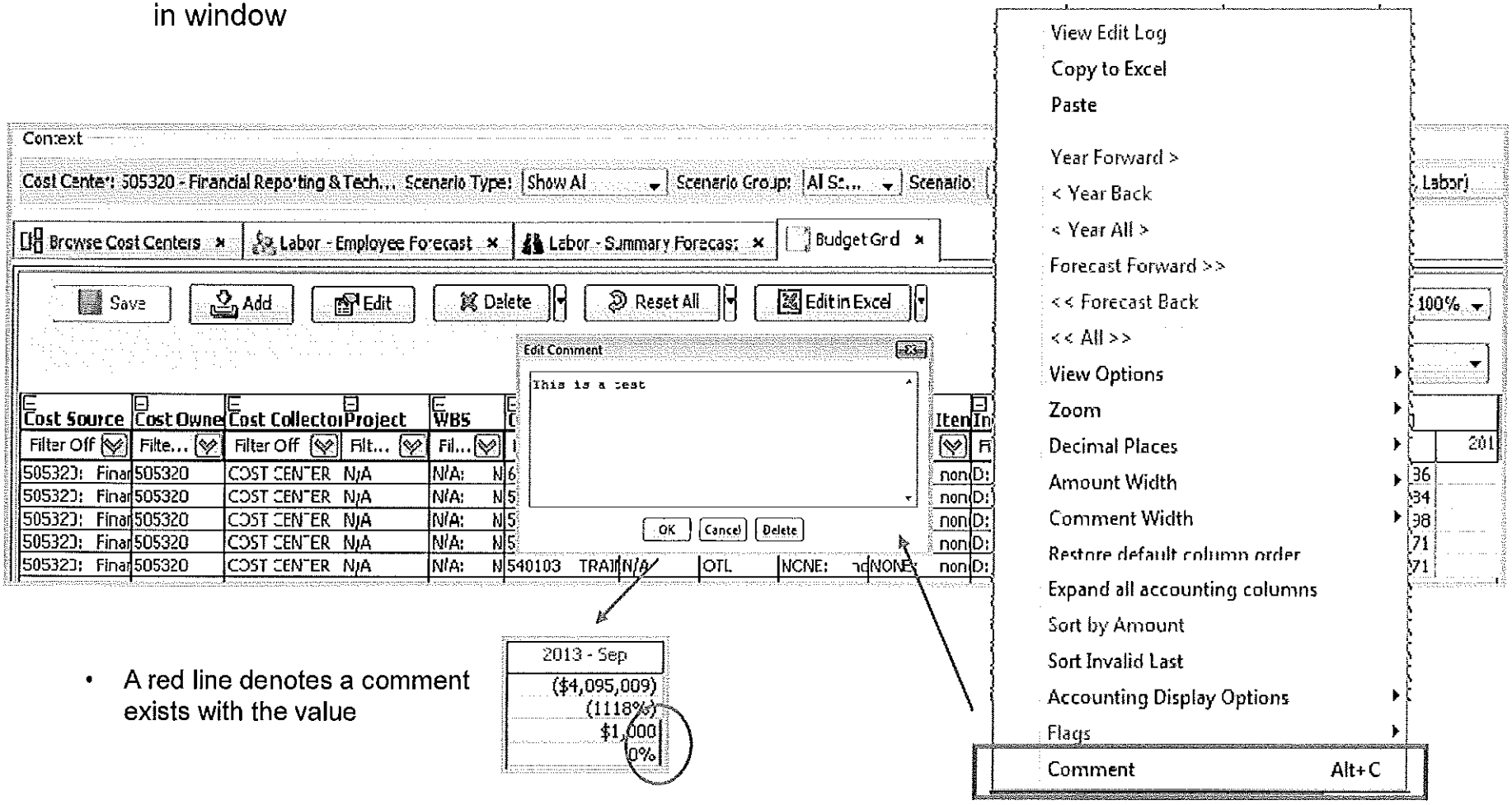
Save | Add | Edit | Delete | Reset All | Edit in Excel Ref Scenario: Budget 2014 (Integration / Business Process Test) Record 0 of 0 Types: Filter Off Zoom: 10... Filter: --None--

Cost Source	Cost Owner	Cost Collector Ty	Project	WBS	Inte	Comment	Amount Type	2014							
								2014 - Jan	2014 - Feb	2014 - Mar	2014 - Apr	2014 - May	2014 - Jun	2014 - Jul	2014 - Aug
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$386	$386	$386	$386	$386	$386	$386	$386
							Ref	$386	$386	$386	$386	$386	$386	$386	$386
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$284	$284	$284	$284	$284	$284	$284	$284
							Ref	$284	$284	$284	$284	$284	$284	$284	$284
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$198	$198	$198	$198	$198	$198	$198	$198
							Ref	$198	$198	$198	$198	$198	$198	$198	$198
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$171	$171	$171	$171	$171	$171	$171	$171
							Ref	$171	$171	$171	$171	$171	$171	$171	$171
505320: Financial	505320: Financial	COST CENTER: Cos	N/A: No Project	N/A: N/A	N/A:		Dollars	$171	$171	$171	$171	$171	$171	$171	$171
							Ref	$171	$171	$171	$171	$171	$171	$171	$171
Active Flags: In-Budget;						Column Totals	Dollars	$1,210	$1,210	$1,210	$1,210	$1,210	$1,210	$1,210	$1,210
							Ref	$1,210	$1,210	$1,210	$1,210	$1,210	$1,210	$1,210	$1,210

Budget Grid Functions - Comments

8

- Comment fields available on both grid and dollar/hour values
  - Right-click on the row you want to enter a Comment
  - Select Comment column and enter comment in window
  - Right-click on the actual dollar value and enter comment in window



- A red line denotes a comment exists with the value

Budget Grid Functions - Data Entry

9

- Enter values in data fields
- Change column or row level totals with automatic spread – annual or monthly
- Enter new column total for 2014 and press Enter
- Dollars spread proportionate to previous spread

Amount Type	2014 2014 Total
Dollars	$2,058
Dollars	$3,404
Dollars	$2,374
Dollars	$2,058
Dollars	$4,631
Dollars	$14,524

Existing total

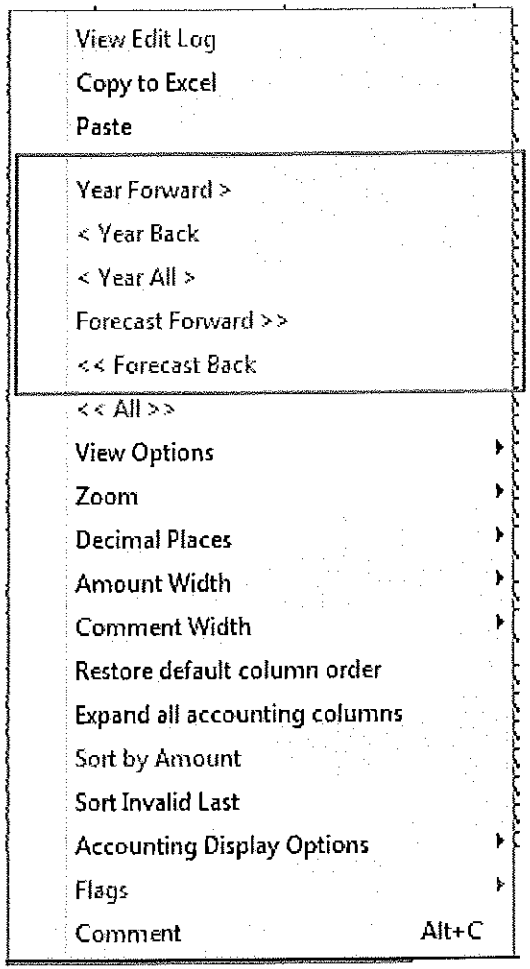
Amount Type	2014 2014 Total
Dollars	$14,166
Dollars	$23,439
Dollars	$16,347
Dollars	$14,166
Dollars	$31,882
Dollars	$100,000

Enter new total

Privileged & Confidential

Budget Grid Functions - Forecasting Options

- Year Forward - Year Back
  - Year Forward - Copy value from one month to remaining months in year
  - Forecast Forward - Copy value in current year to outer year

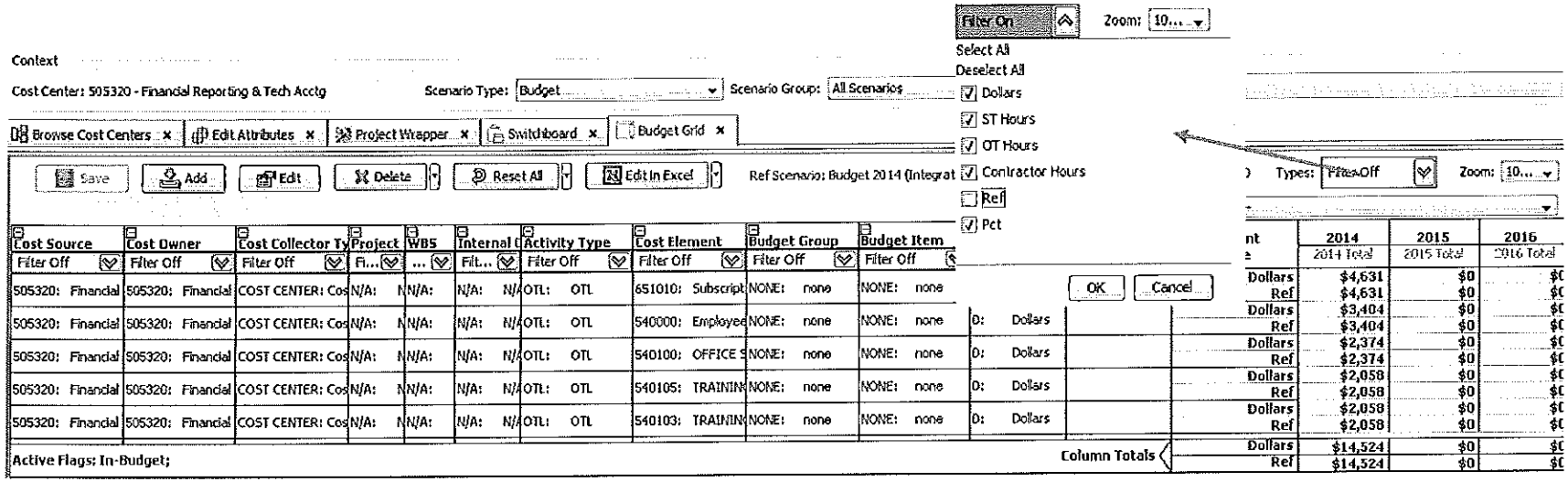


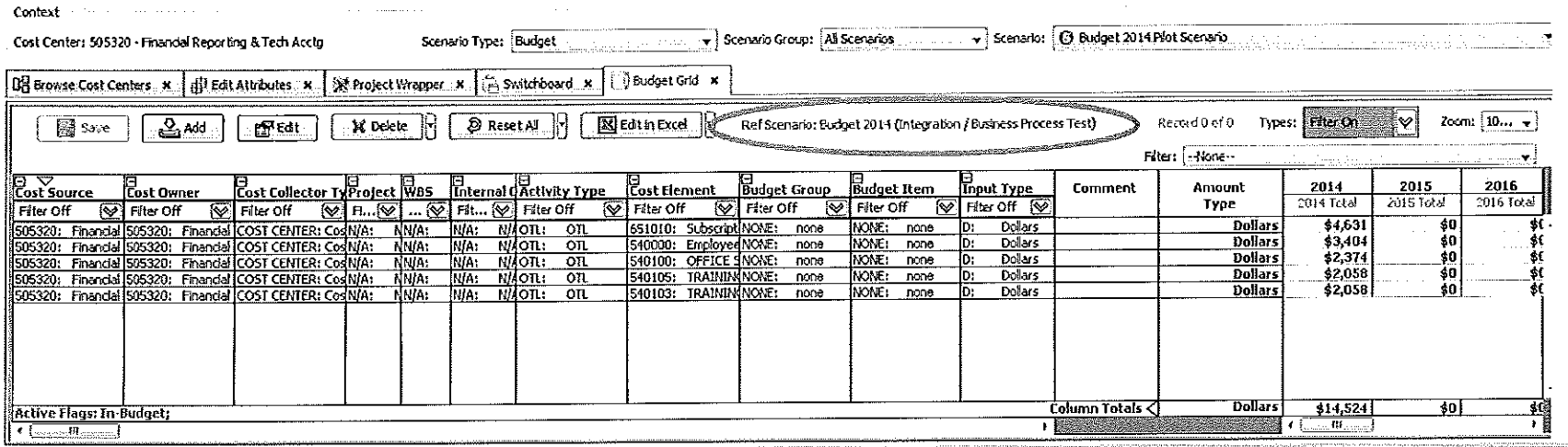
2013	2014				
2013 Total	2014 - Jan	2014 - Feb	2014 - Mar	2014 - Apr	2014 - May
$4,631	$100	$100	$100	$100	$100
$3,404	$0	$0	$0	$0	$0
$2,374	$0	$0	$0	$0	$0
$2,058	$0	$0	$0	$0	$0
$2,058	$0	$0	$0	$0	$0

Dollar value copies to remaining months

Budget Grid Functions - Reference Scenario

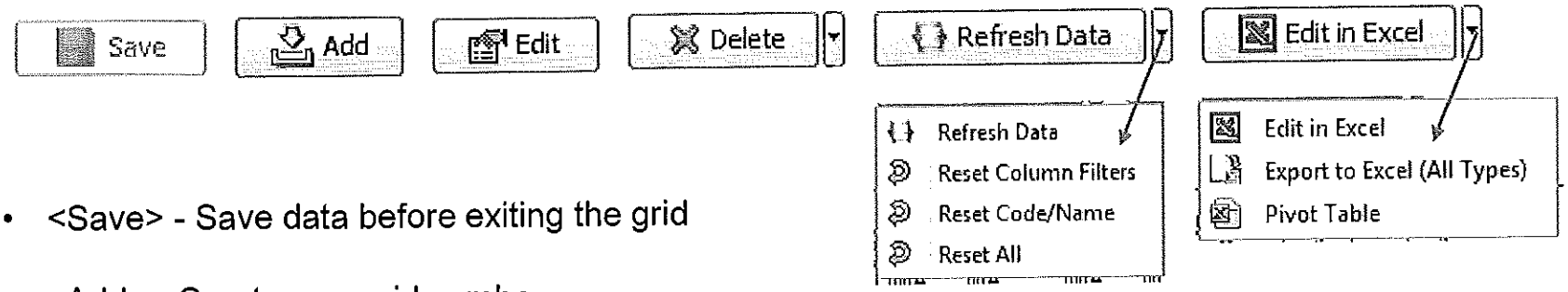
- UIP Grid allows for direct comparisons between scenarios (called "Reference Scenarios")
- Reference Scenarios are set by System Administrator
- Toggle by clicking on "Type" filter and selecting/deselecting "Ref"





12

- Basic Functions



- <Save> - Save data before exiting the grid
- <Add> - Create new grid combo
- <Edit> - Change a cost collector combo
- <Delete> - Remove a cost collector combo
- <Refresh Data> - Update grid with most recent changes/data
- <Reset Column Filters>
- <Reset Code/Name>
- <Reset All>

  } - Restores accounting data columns to original settings

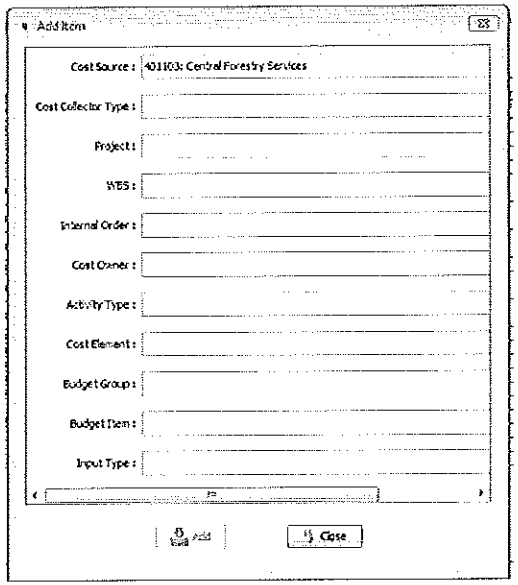
- <Edit in Excel> - Copies Grid data (Directs) to Excel for editing and then pastes it back into UIP.
- <Export to Excel (All Types)> - Sends ALL Budget Grid data to Excel to SAVE (can be imported).
- <Pivot Table> - Sends Budget Grid data to Excel and sets it up in Pivot Table format.

Add Budget Grid Data Overview

Multiple ways to enter data to the Grid



Add button with Edit Combo drop down

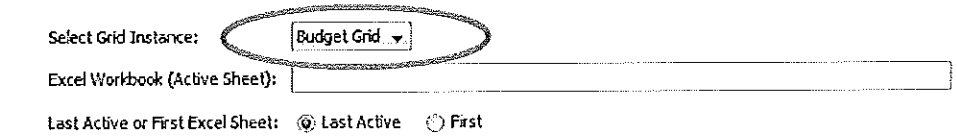


Edit in Excel or
Right Click in grid and
select *"Copy to Excel"*



	A	B	C
1			
2	Cost Center	Receiving Cost Center	Cost Collector Type
3	0000401001: Central Reg	0000401001: Central Regi	COST CENTER: Cost Ce
4	0000401001: Central Reg	0000401001: Central Regi	COST CENTER: Cost Ce
5	0000401001: Central Reg	0000401001: Central Regi	COST CENTER: Cost Ce
6	0000401001: Central Reg	0000401001: Central Regi	COST CENTER: Cost Ce

To import saved data return to Browse Cost Center screen and right click – select *"Import" (file must be on C: drive)*



All entries are validated prior to save to ensure accurate values were selected

Add Budget Grid Combination

Right click in box to either select value or enter directly

1. <Add> button with drop down

Cost Centers will be limited based on the user security →

Cost Collector defaults "N/A" if Cost Collector Type not selected. A drop down of valid cost collectors for owner selected will display →

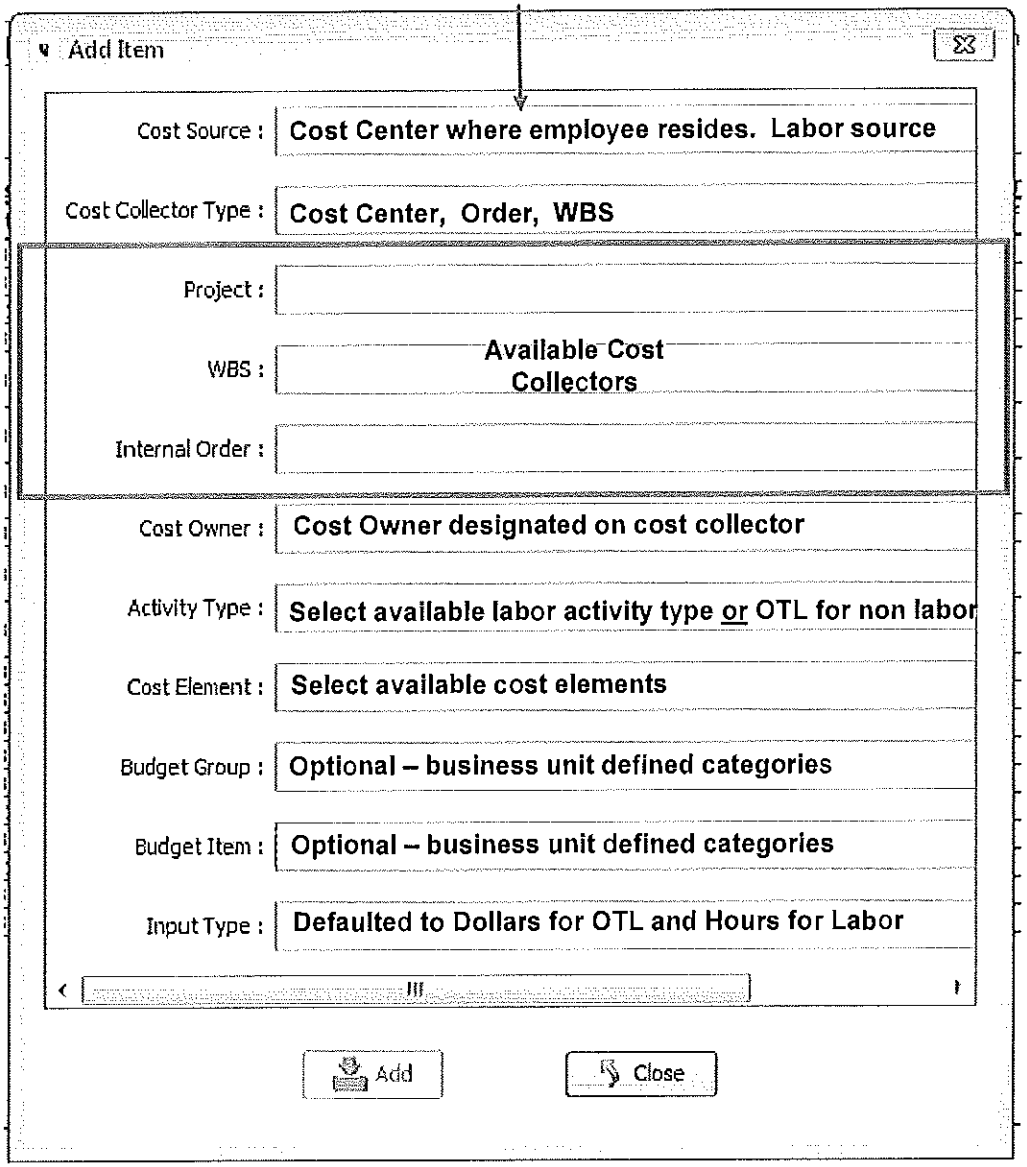
When budgeting Labor, this will be the Cost Center being billed for the Labor.
When budgeting OTL, this will be the same as the Cost Source →

Will be required only for Labor. Should be set to 'OTL' when budgeting OTL. Contractor hours and dollar value available →

Appropriate cost elements display (labor or OTL or Contractor/Prof Services). Ability to lock cost elements →

Allows user to apply more detail to the budget. Budget Groups might include Travel or Office Supplies. →

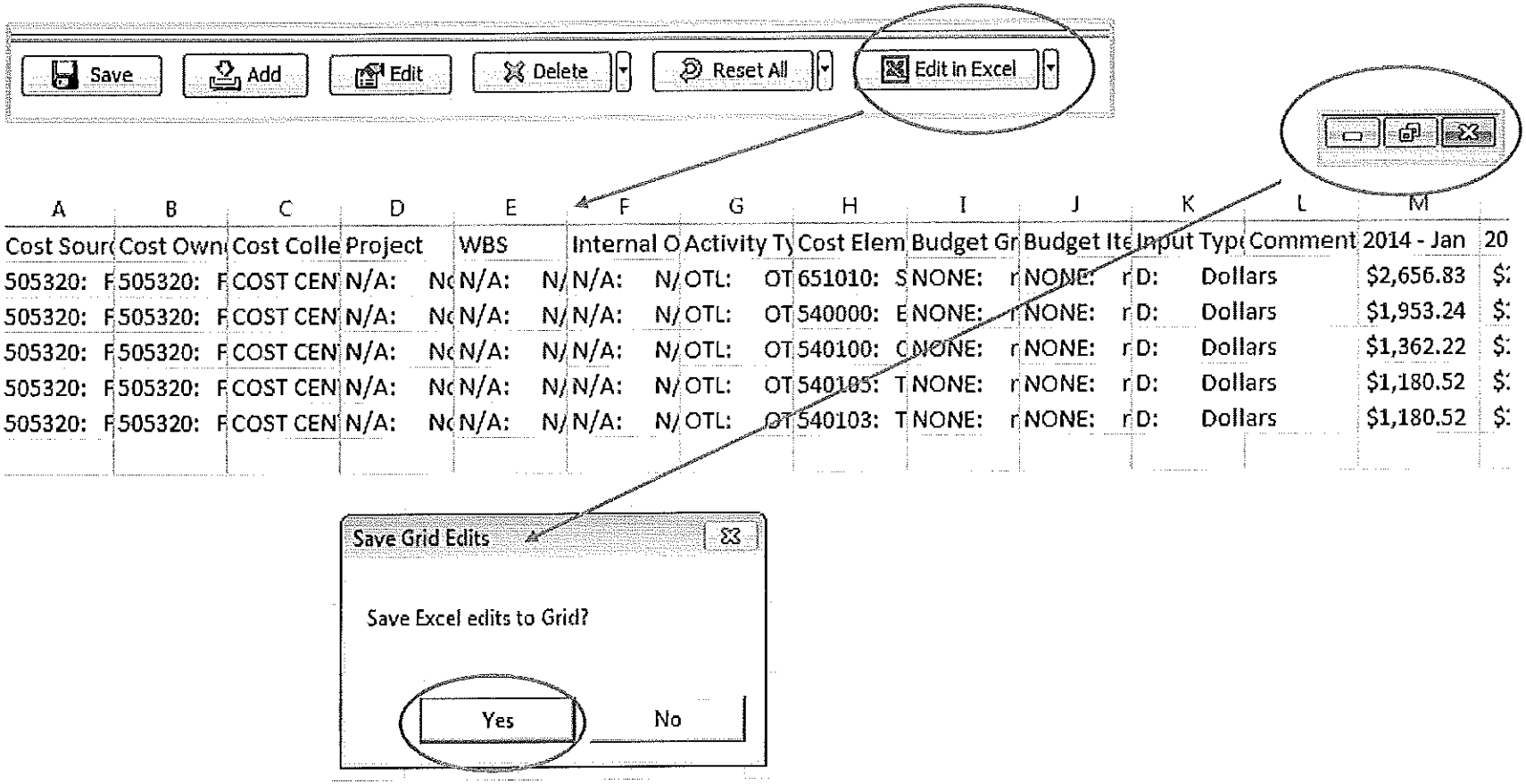
Allows user to apply more detail to the budget. Budget Items might include Airfare, Hotel and Meals for the Budget Group of Travel. →



Add Budget Grid Combination

2 Edit in Excel

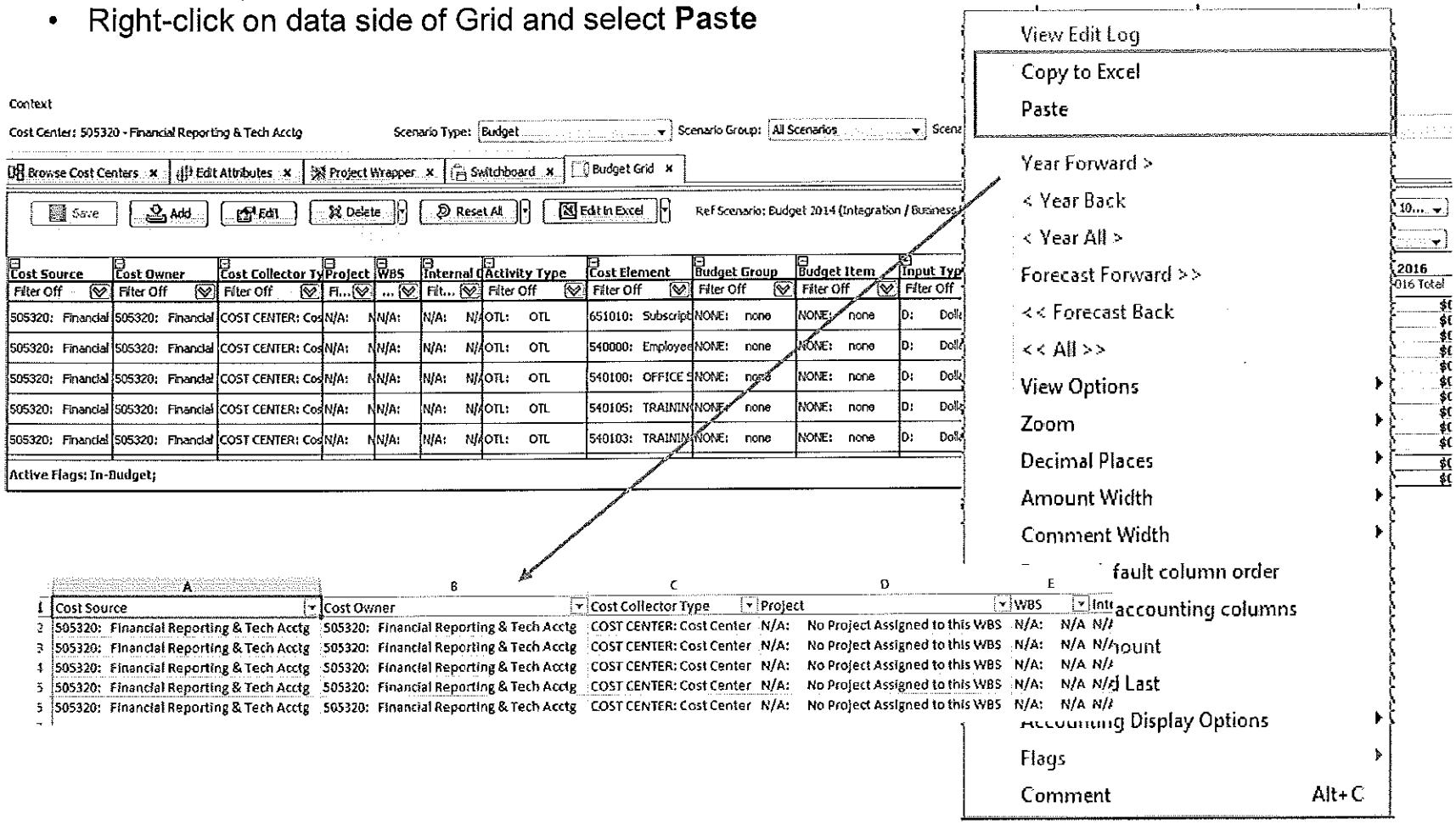
- Select **Edit in Excel** button
- When Excel opens, enter values in desired cells' dollars or make adjustments to existing values
- Click the "X" button to save back to the grid



Add Budget Grid Combination

3 Copy to Excel

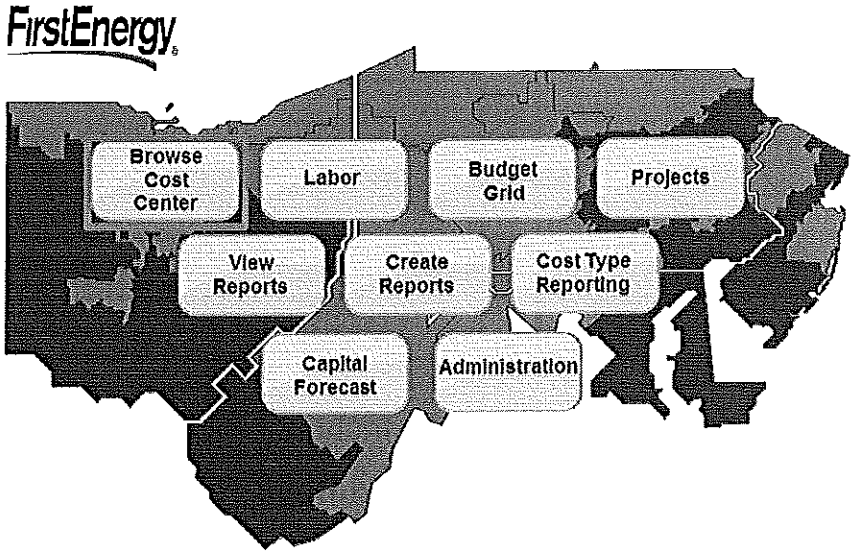
- Right-click on data side of Grid and select **Copy to Excel**
- Enter values in desired cells
- When completed, highlight sheet, select "copy"
- Right-click on data side of Grid and select **Paste**

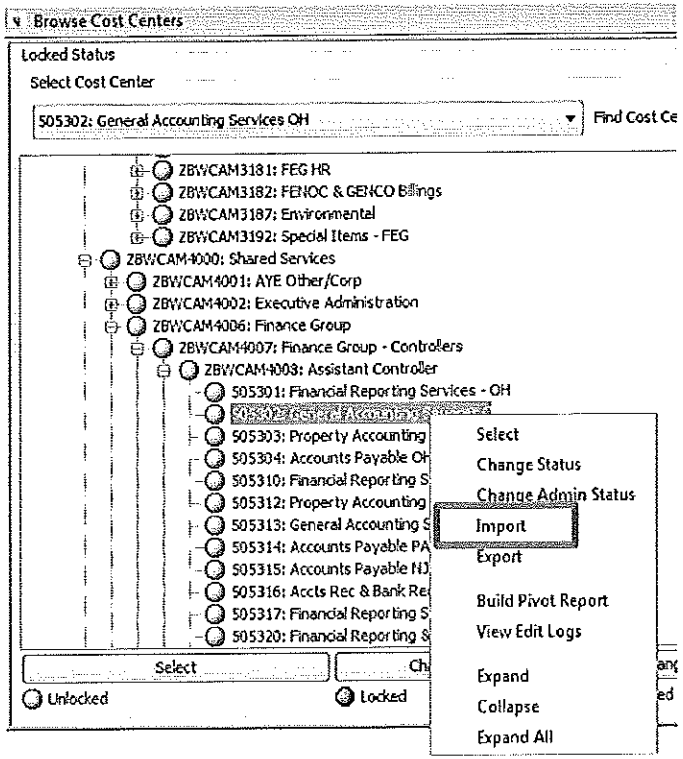


Add Budget Grid Combination

4 Import Budget Grid Data

- Open **FE Switchboard**
- Click **Browse Cost Center**
- Right click on any Cost Center
- Select "Import" from the menu window



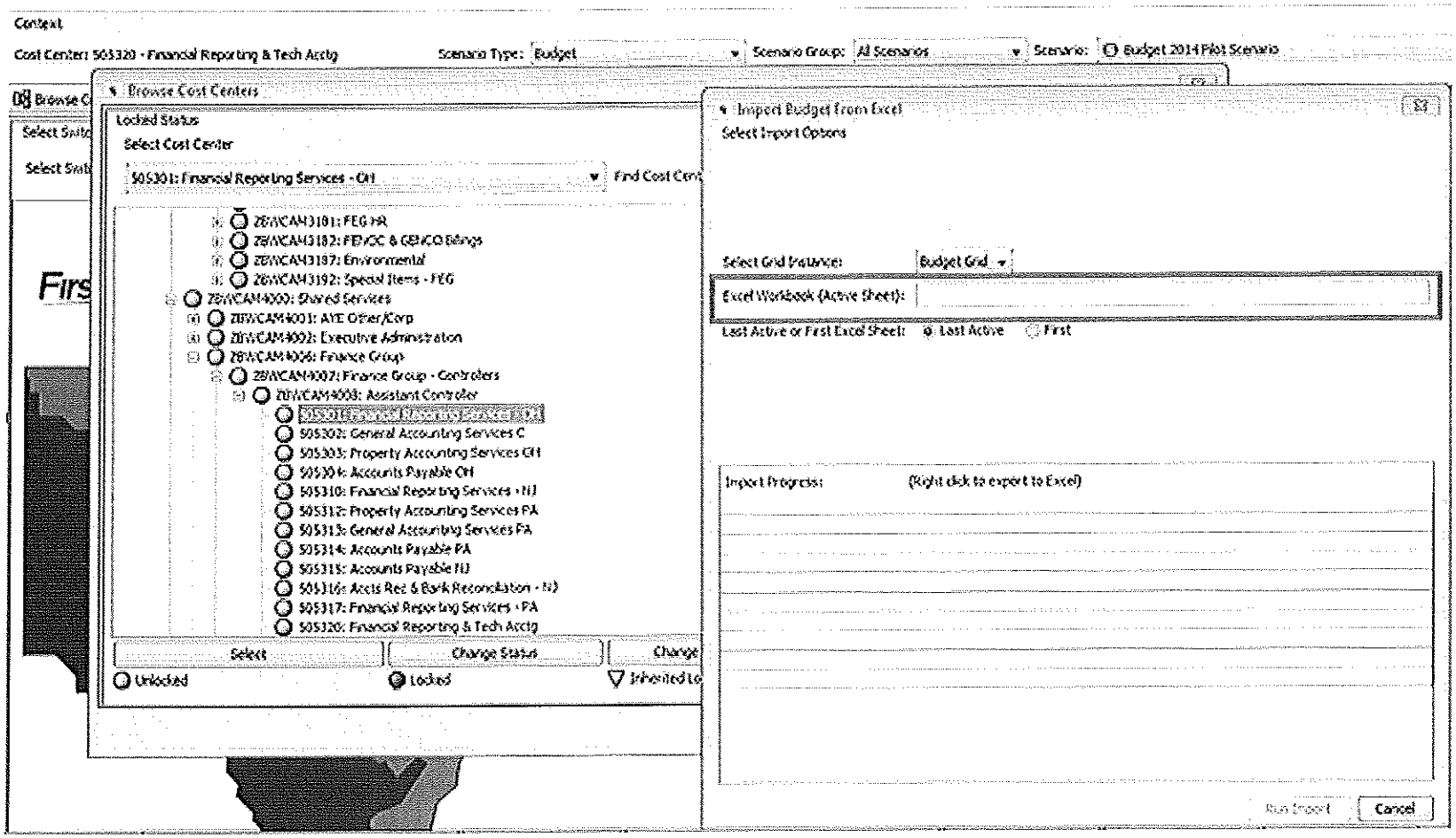


Note: This method is primarily used for data imports. Users should select the **Edit in Excel** button or **Copy to Excel** option for basic budget grid entry

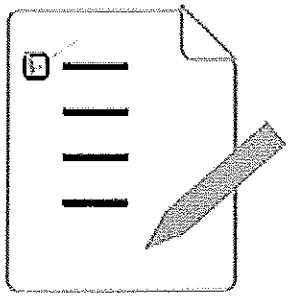
Add Budget Grid Combination

continued

4. Click in the "Excel Workbook (Active Sheet)" window
   - Browse through "C:/" drive to find import spreadsheet
   - NOTE: Spreadsheet must have all the same fields as displayed on the budget grid



Exercise #1 – Budget Grid Entry and Functionality



- Customize your Grid
- Add a budget grid combination by using the Add button
- Export the budget Grid to Excel and make additional changes. Populate multi-year. Copy back to Grid
- Perform other grid functions
- Add an existing Budget Group and Budget Item for a selected Cost Center
- Add comments to various Grid combinations
- Create a new Budget Group and Budget Item for a selected Cost Center
- Start developing your Budget Group and Budget Item categories for the 2014 budget process. *Users should complete their list on paper before creating in UIPlanner to ensure consistency and avoid duplication*

Project Planning and Tracking

Project Planning and Tracking Overview

- SAP Projects and WBS elements will be used for all current year projects
  - Project/WBS list from SAP will be refreshed every 60 minutes along with all attributes
- Planning Projects (conceptual projects) will be created and managed in UIPlanner for multi-year forecasts
  - Create Planning Projects using templates
  - UIPlanner will derive key attributes - user can populate remaining attributes
  - Some attributes will be required fields
- There is a process for when a Planning Project becomes "real", i.e., is in SAP
- Current list of attributes is on the next slide. Ability to create additional attributes

Current Year	Multi-Year
SAP Projects	**UI Planning Projects**
• Approved projects in the current year • Project definition and WBS elements exists in SAP • Ability to track actuals vs. budget	• Unapproved Projects in the queue • Planning projects (project definition and WBS elements) mirror real SAP structures but utilize UIP naming conventions • SAP project templates utilized as starting point

- Mirroring the SAP project to the UI Planning Project ensures important attributes such as the Costing Sheet data are applied accurately and automatically
- Budget close will work in the same manner for the multi-year planning process

PROJECT / WBS ATTRIBUTES IN UIPLANNER

PROJECT

From SAP
- Budget Profile
- Changed By
- Changed On Date
- Company (Required)
- Cost Object
- Created By
- Created On Date
- Definition
- Description
- Estimated In Service Date
- Forecast Finish Date (FRCST)
- Forecast Start Date
- In SAP (Y/N)
- Integrated Planning
- Interest Profile
- Investment Profile
- Name of Person Responsible
- Network Profile
- Number
- Object Class
- Object Number
- Owning Center
- Person Responsible
- Plant
- Profit Center
- Start Date (Required)
- Tax Jurisdiction

xRPM
- xRPM Number
- Bucket Name
- Business Unit Sponsor
- CART Data Fields (determine which ones)
- CART ID Number
- Detailed Description
- Multi-Year Flag

RPA
- RPA Number
- Sponsor (bulk, region, other)
- Sponsor Need Date
- Status
- Initiative Code (used by Transmission to provide additional visibility
- Lead (name)

One List
- One List Number
- Sponsor (actual name)
- Plant Designator
- Plant Unit # (BV1, etc)
- Investment Profile Text Field (define a sub category)
- Program Manager (actual name)
- Nuclear Fuels (Y/N)
- Outage Code (denotes which outage)
- Text Field (EUCG capital category for benchmarking)
- Text Field (text box for reporting owner name)

Other
- Profile
- End Date (Required)
- Budgetable (Y/N)
- In-Budget Flag

WBS

From SAP
- Company Code
- Cost Center
- Project
- Profit Center
- Object Class
- Estimated In-Service Date (PRPS)
- Closing Option
- Costing Sheet
- Project Type
- Element String
- Element (PSPID)
- Element (PSPNR)
- Interest Profile
- Base/Recoverable/Major Projects
- Created On (date)
- Created By
- Changed On (date)
- Changed By
- Requesting Cost Center

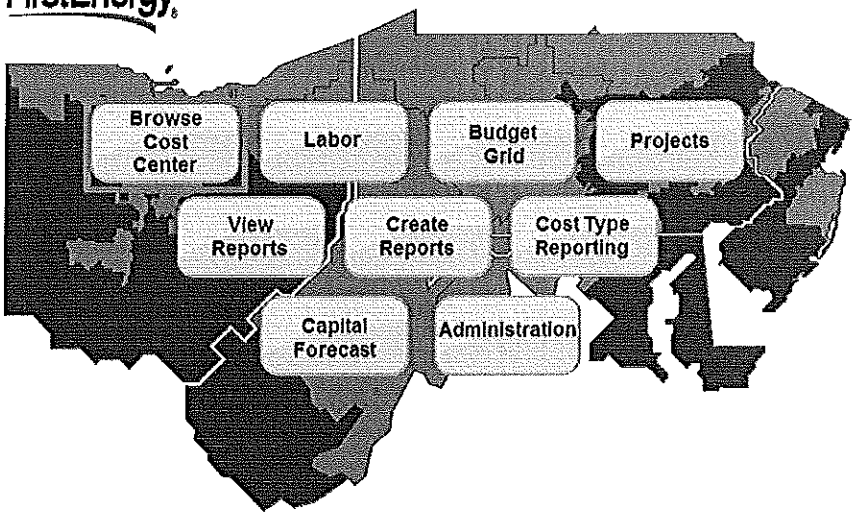
From SAP
- Investment Profile (mandatory, maintain, value add, improve)
- Scale of investment
- Reason for Environmental Investment
- Investment Reason
- Costing Variant
- Cost Object
- Object Number
- Planning Element
- Integrated Planning
- Priority
- Currency
- Level
- Technically Complete
- Tax Jurisdiction
- Name of Person Responsible
- Person Responsible
- Plant
- Overhead Key
- In SAP

PowerPlant
- Depr Group
- Estimated In-Service Date (PPLANT)
- Eligible for AFUDC
- Eligible for CPI
- AFUDC Type
- In PowerPlant

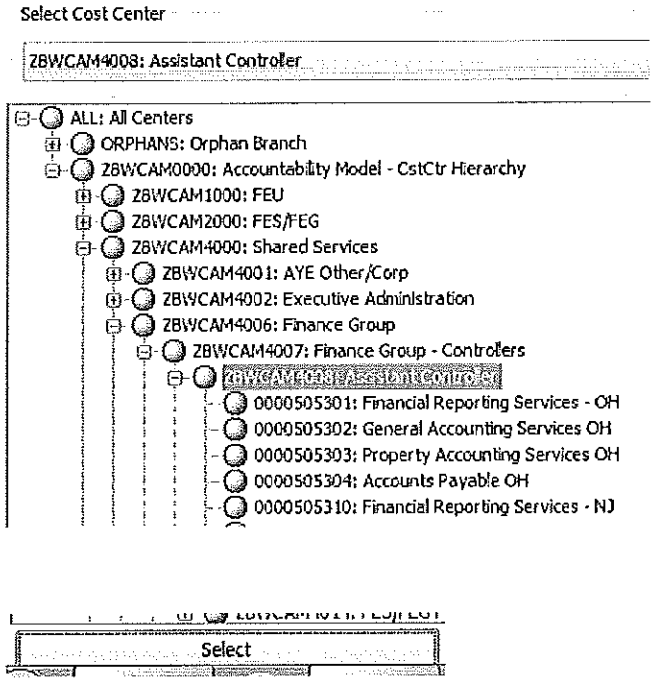
Other
- Budgetable (Y/N)
- Status
- Template (Y/N)
- Element Description

Project Planning and Tracking Startup

1. Define a Context Cost Center
   - Open the **FE Switchboard**
   - Click **Browse Cost Center**

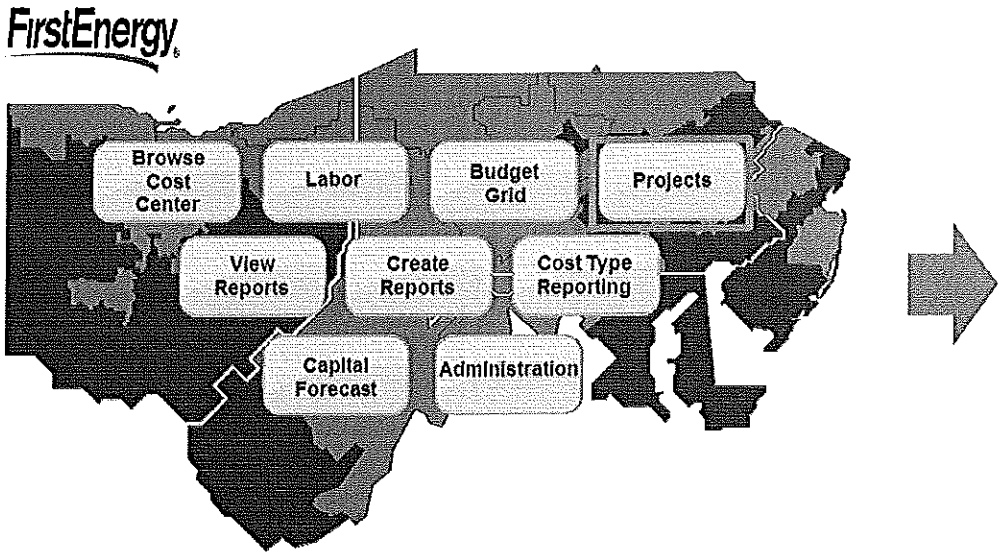


2.
   - Select a Cost Center (either double-click Cost Center or highlight Cost Center and click the **Select** button on the bottom of screen)
   - **Note:** Select the ALL node to view a full list of projects

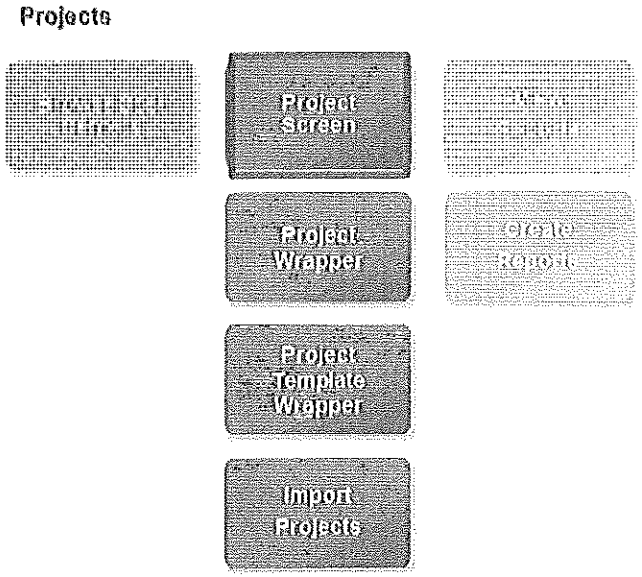


Project Planning and Tracking Startup

3 Open Project Screen
- Return to the **FE Switchboard**
- Click on the **Projects** button



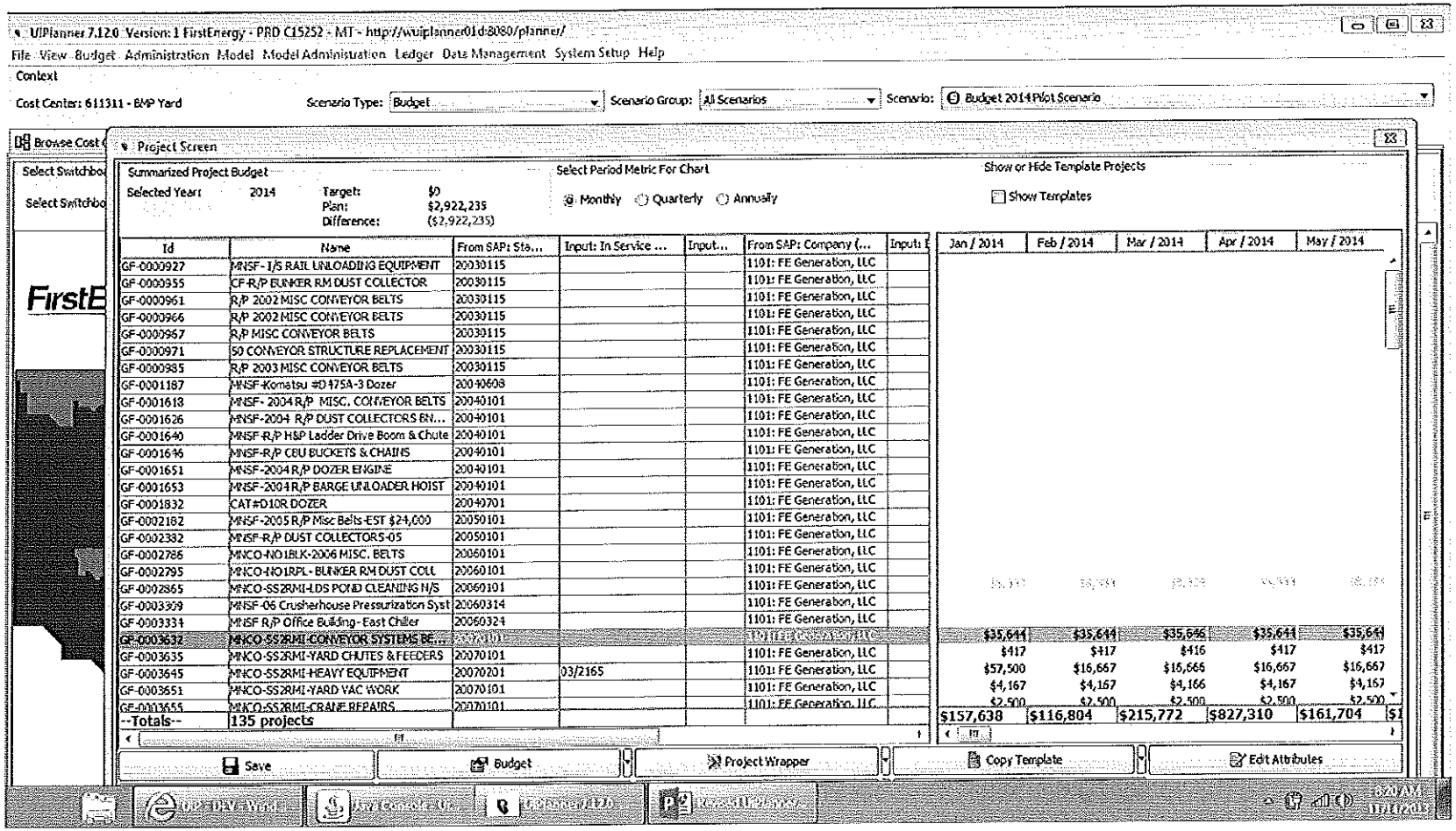
4
- Click **Project Screen** menu item



Project Planning and Tracking Screen Navigation

5

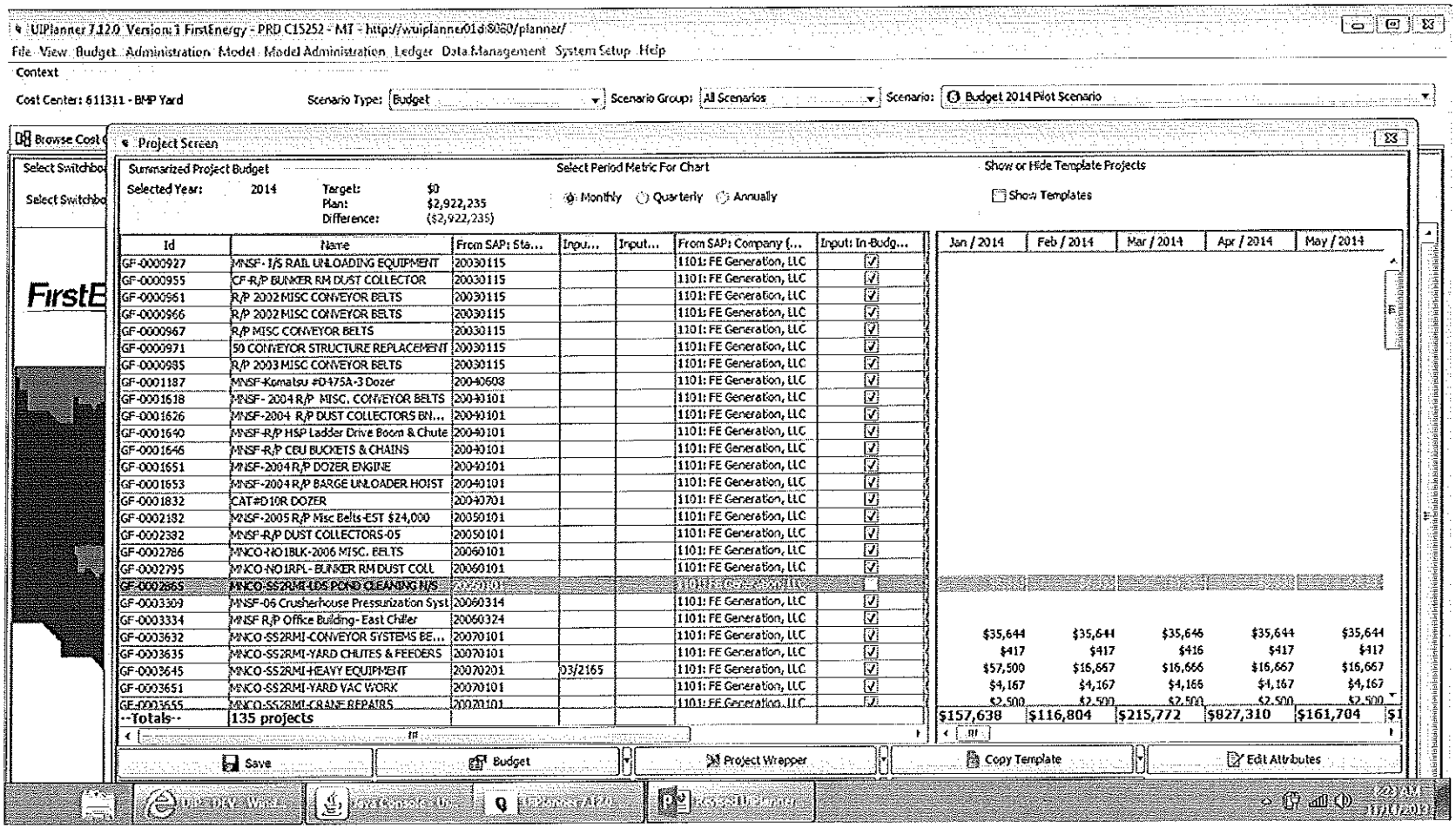
- Move projects from year to year
  - Select dollar amount for a given project and drag to a different year
  - Changes will automatically update Grid keeping the Project Screen and Budget Grid in sync
  - Note: you cannot drag projects that have already started (i.e. have amounts in actuals months)
- Change the column display (Monthly, Quarterly, or Annual)



Project Planning and Tracking Screen Navigation

6

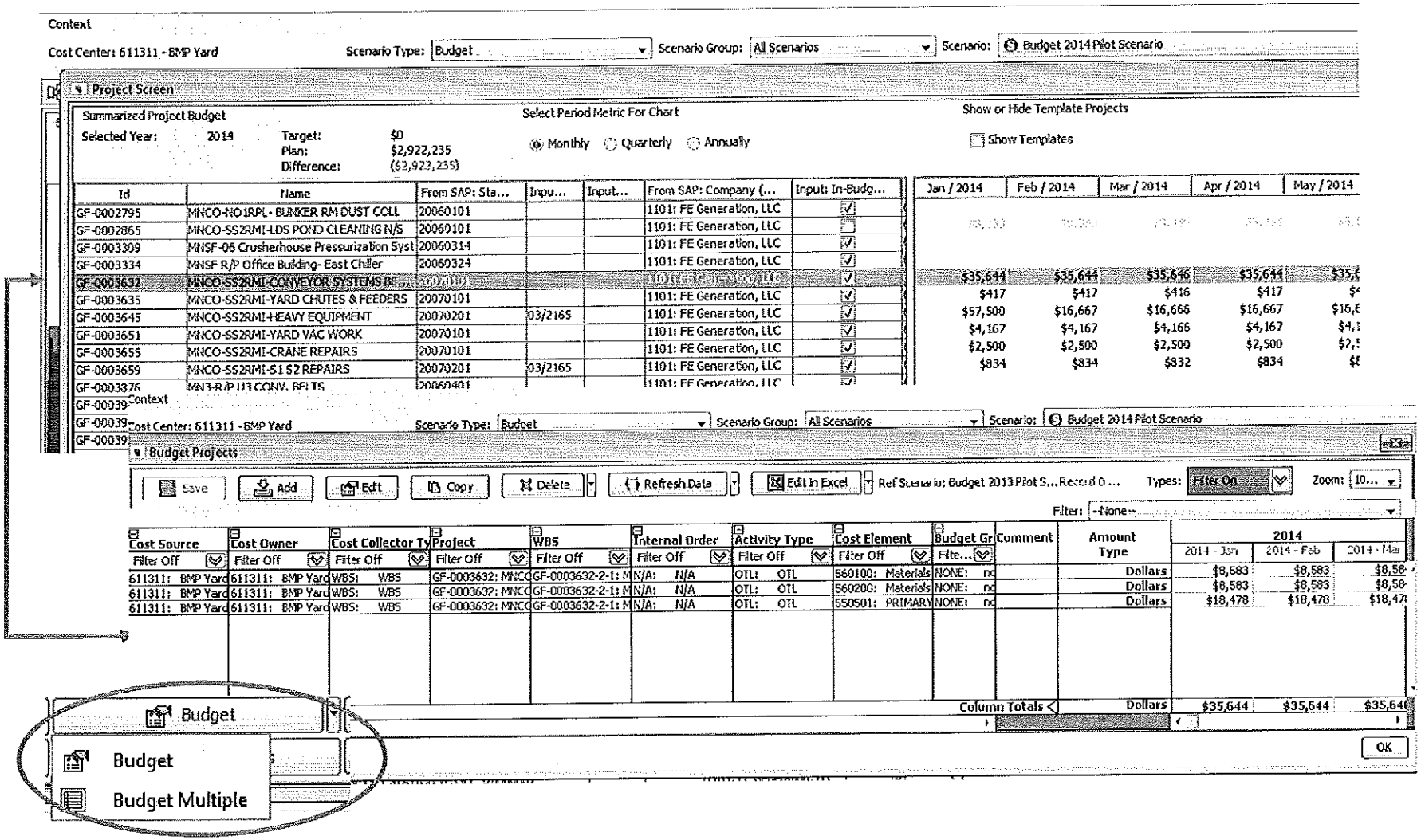
- Turn projects on and off (using the In-Budget flag)
  - The project spending will be grayed out
  - It will be excluded from the totals
  - Click on a column, and the top of the screen shows the totals against the target for that year



Project Planning and Tracking Budgeting

7

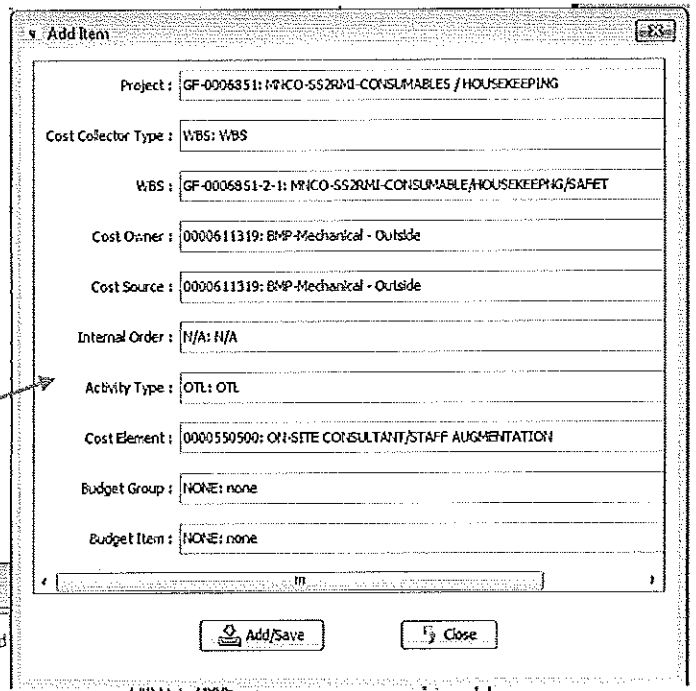
- Select Budget button on bottom of screen to view projects in the budget grid
- Use the droplist on the side of the button to choose whether to budget one project or multiple projects

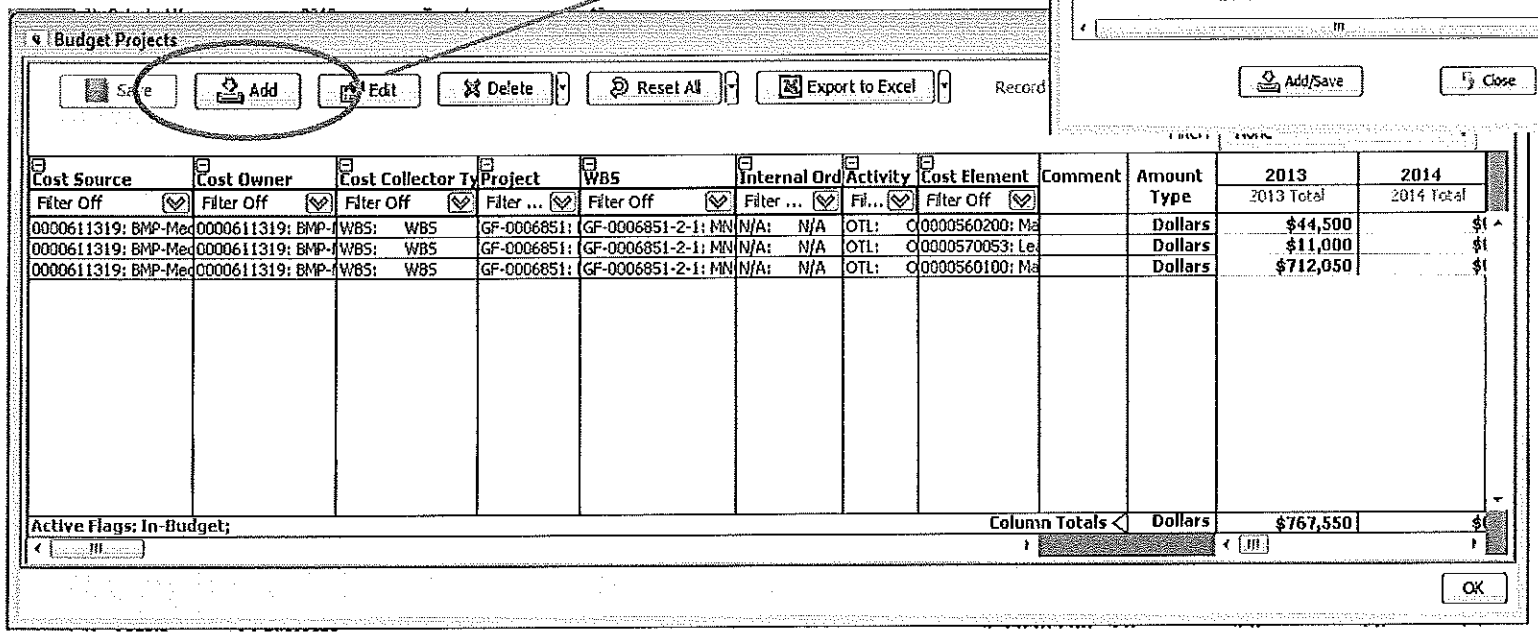


Project Planning and Tracking - Add Combo

8

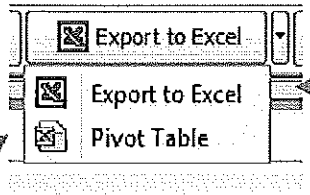
- Budget Grid - Project View
  - All Grid functionality
    - Dollars, Hours
    - Enter or paste from Excel
    - Monthly, Annual
    - Grouping and filters
    - Right-click options
  - Add Combos
    - Project Validations - fills in the available choices for the next field
    - Some fields are prepopulated





Project Planning and Tracking – Export to Excel / Pivot Table

9 • Select **Export to Excel/Pivot** button on bottom of screen to send the screen contents to Excel
  • Select the dropdown on the right of the button to choose raw Excel or a Pivot table



Microsoft Excel - Data Export 1375311570091.txt.xls

	A	B	C	D	E	F	G	H	I	J	K
1	Id	Name	Input: In-Budget Flag	From SAP: Interest Profile	F	Input: End Date (Required)	2,013	2,014	2,0	2,0	2,0
2	GF-0002866	MN03-SS2RMI-SO2 CONTRACTOR U3	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,061,231	200,000				
3	GF-0002872	MN01-SS2RMI-SO2 CONTRACTOR U1	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,061,231	74,000				
4	GF-0002873	MN02-SS2RMI-SO2 CONTRACTOR U2	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,061,231					
5	GF-0003520	MNCO-SS2RMI-SCR CLEANING UNIT 1, 2 & 3	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,471,231	425,000				
6	GF-0004017	MNCO-SS2RMI-SBS LICENSE FEE BMP	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,480,118					
7	GF-0004031	MNCO-SS2RMI-HYDROGEN BMP	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,480,118					
8	GF-0004032	MNCO-SS2RMI-CO2 BMP	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,480,118	25,000				
9	GF-0005041	MNCF-R/P NO 1 JOY INTERCOOLERS 2007	TRUE								
10	GF-0005075	MNCO-NO1RPL-SHIFT SUPERVISOR OFFICE REN	TRUE		0000	20,080,331					
11	GF-0005118	MNSF PURCHASE KAWASAKI MULE-2007	TRUE								
12	GF-0005119	MNCO- TELEDYNE MODEL2750 H2 GAS ANALYZER	TRUE								
13	GF-0005357	MNCO-SS2RMI-LUBRICANTS & KEROSENE OPS	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,201,231	280,660				
14	GF-0005358	MNCO-SS2RMI-FLOC STOCK OPERATIONS	FALSE	PRDSTMO: Steam Fossil O&M	0000	20,201,607		195,000			
15	GF-0006356	MNCO-SS2RMI-U1B U2 TRAIN CLG-OPS	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,091,231					
16	GF-0006357	MN03-SS2RMI-U3 ABS/REACTOR-OPS	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,091,231					
17	GF-0006358	MNCO-SS2RMI-REPLACEMENT-VIC P&H ETC	TRUE	PRDSTMO: Steam Fossil O&M	0000	20,091,231					

A2 fx From SAP: Profit Center

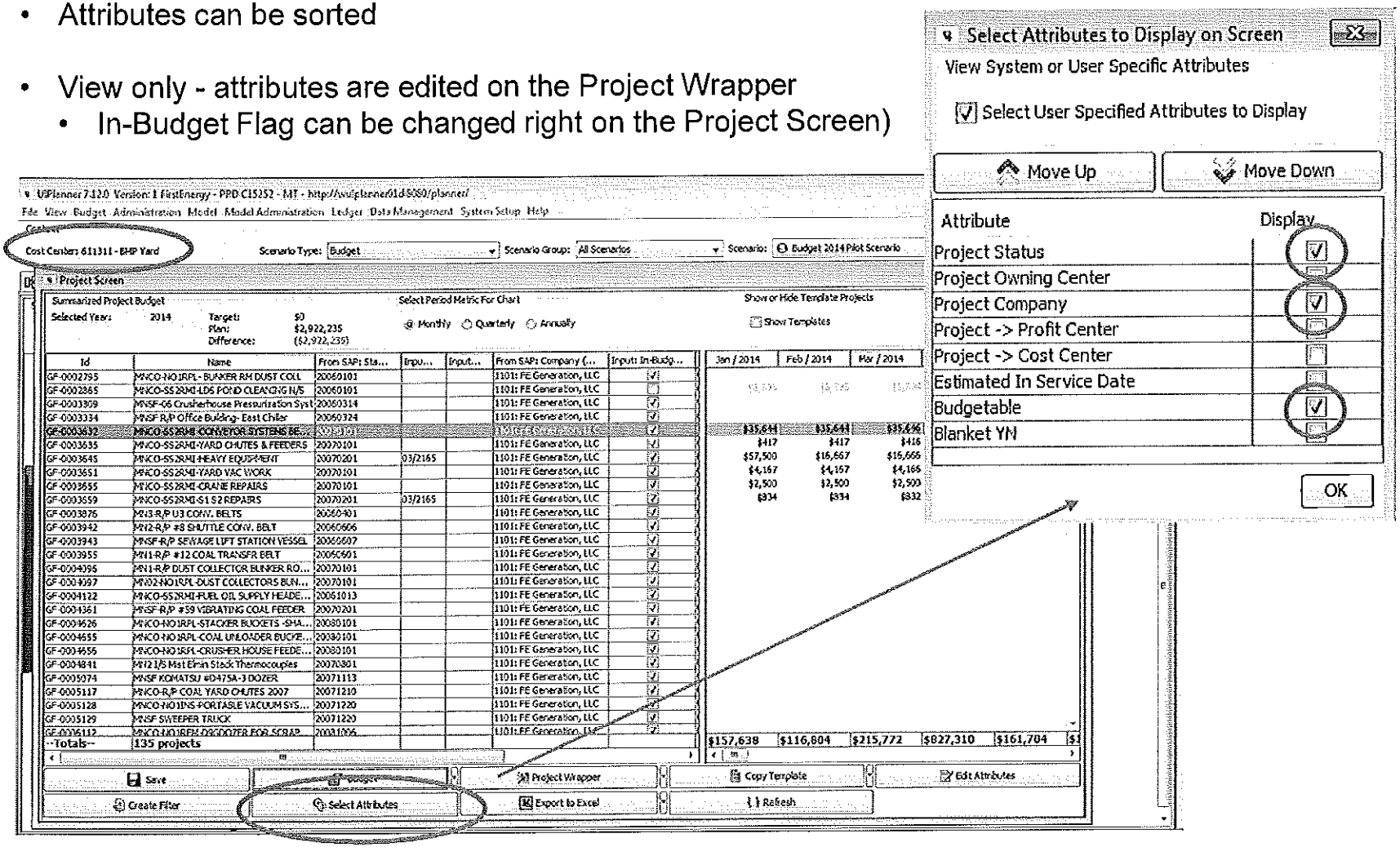
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	Input: End Date (Required)	(All)													
2	From SAP: Profit Center	(All)													
3	From SAP: Interest Profile	(All)													
4	Input: In-Budget Flag	(All)													
5	Last Used By	(All)													
6	Scenario	(All)													
7															
8	Sum of Value		Year	Month											
9			2014												2014 Total
10	Project	Last Used	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
11	GF-0002866: MN03-SS2RMI-SO2 CONTRACTOR U3	(blank)	16667	16667	16666	16667	16667	16666	16667	16667	16666	16667	16667	16666	200000
12	GF-0002866: MN03-SS2RMI-SO2 CONTRACTOR U3 Total		16667	16667	16666	16667	16667	16666	16667	16667	16666	16667	16667	16666	200000
13	GF-0002872: MN01-SS2RMI-SO2 CONTRACTOR U1	(blank)	74000												74000
14	GF-0002872: MN01-SS2RMI-SO2 CONTRACTOR U1 Total		74000												74000
15	GF-0003520: MNCO-SS2RMI-SCR CLEANING UNIT 1, 2 & 3	(blank)	35417	35417	35416	35417	35417	35416	35417	35417	35416	35417	35417	35416	425000
16	GF-0003520: MNCO-SS2RMI-SCR CLEANING UNIT 1, 2 & 3 Total		35417	35417	35416	35417	35417	35416	35417	35417	35416	35417	35417	35416	425000
17	GF-0004032: MNCO-SS2RMI-CO2 BMP	(blank)	2083	2083	2084	2083	2083	2084	2083	2083	2084	2083	2083	2084	25000
18	GF-0004032: MNCO-SS2RMI-CO2 BMP Total		2083	2083	2084	2083	2083	2084	2083	2083	2084	2083	2083	2084	25000
19	GF-0005357: MNCO-SS2RMI-LUBRICANTS & KEROSENE OPS	(blank)	23389	23389	23387	23389	23389	23387	23389	23389	23387	23389	23389	23387	280660
20	GF-0005357: MNCO-SS2RMI-LUBRICANTS & KEROSENE OPS Total		23389	23389	23387	23389	23389	23387	23389	23389	23387	23389	23389	23387	280660
21	GF-0005358: MNCO-SS2RMI-FLOC STOCK OPERATIONS	(blank)													
22	GF-0005358: MNCO-SS2RMI-FLOC STOCK OPERATIONS Total														
23	GF-0006957: MNCO-SS2RMI-NON-SO2 CONTRACTORS OPS	(blank)							27917	27917	27916	27917	27917	27916	167500
24	GF-0006957: MNCO-SS2RMI-NON-SO2 CONTRACTORS OPS Total								27917	27917	27916	27917	27917	27916	167500
25	Grand Total		151,556	77,556	77,553	77,556	77,556	77,553	105,473	105,473	105,469	105,473	105,473	105,469	1,172,160

Project Planning and Tracking - Select Attributes

10

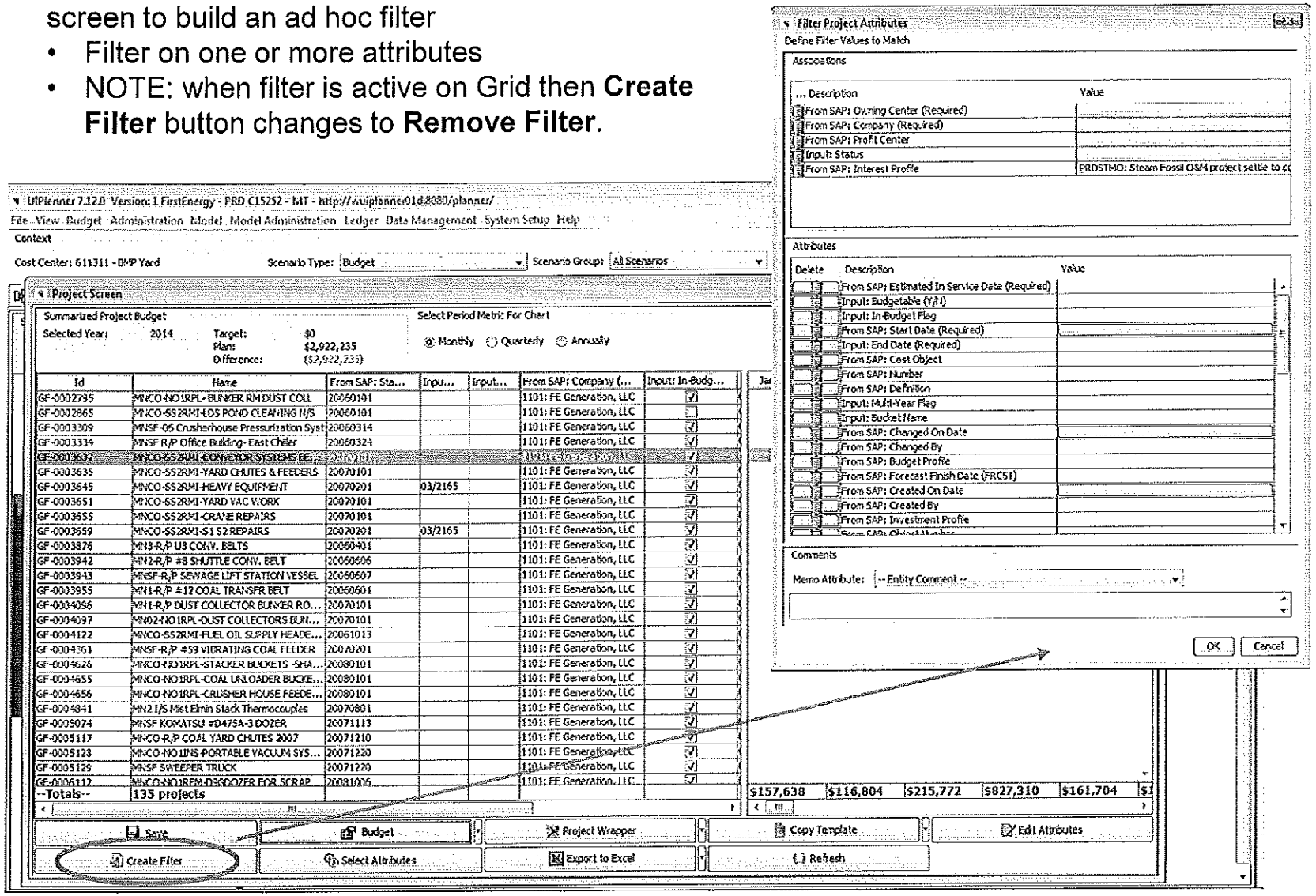
- Users can customize the project screen and view project attributes
- Select the **Select Attributes** button on bottom of screen
- Click on/off attributes you want to display
- Attributes can be sorted

- View only - attributes are edited on the Project Wrapper
  - In-Budget Flag can be changed right on the Project Screen)



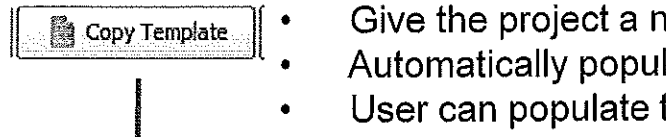
Project Planning and Tracking - Filters

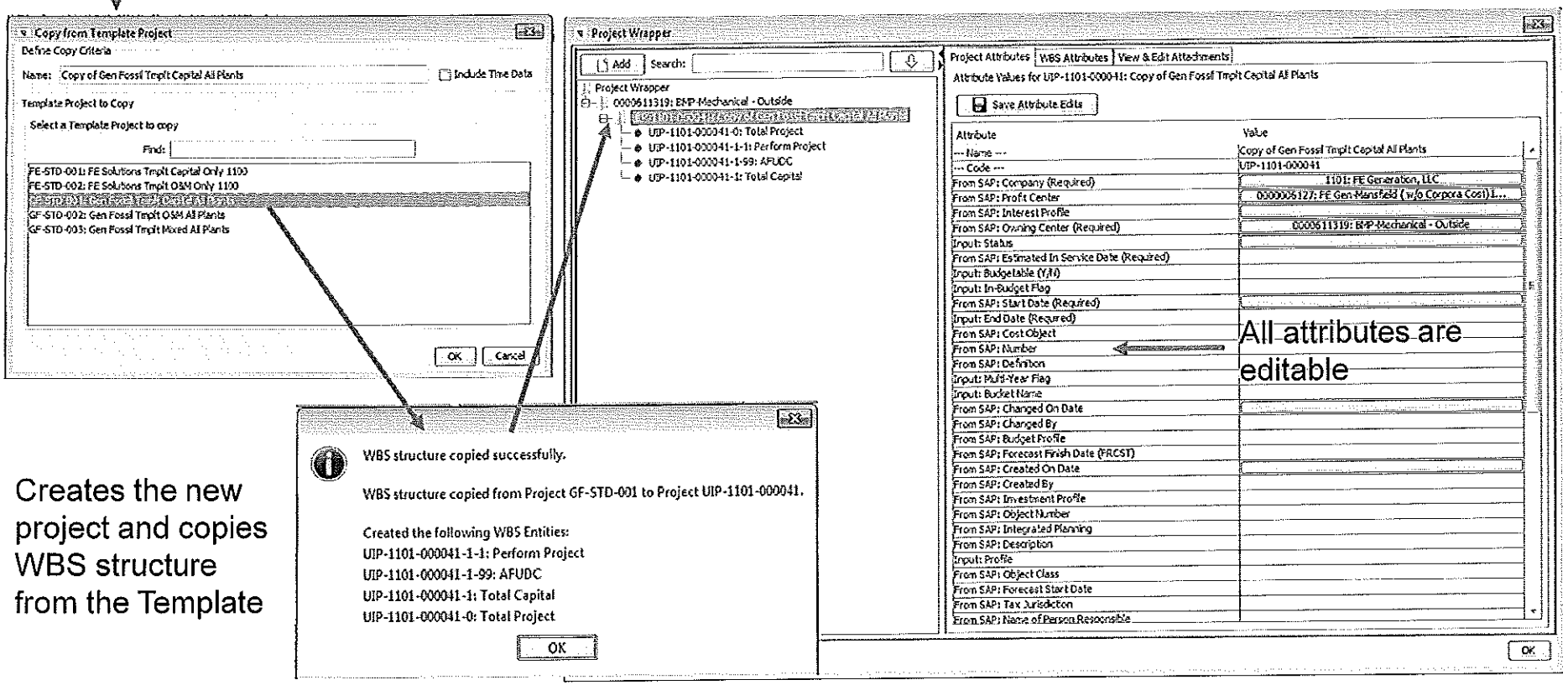
- Select the **Create Filter** button on the bottom of the screen to build an ad hoc filter
  - Filter on one or more attributes
  - NOTE: when filter is active on Grid then **Create Filter** button changes to **Remove Filter**.



Project Planning and Tracking - Create New Project

12 • Create Planning Project / WBS
  - Planning Projects/WBS will be created in UIPlanner
  - Based on Template Projects brought in from SAP
  - Hit the Copy Template button at the bottom of the Project Screen
    - Select a template from the list (templates are at rollup CC; available to CC under)
    - Give the project a name (starts with a default Copy of . . . .)
    - Automatically populates key elements (Company, Cost Center, Project, etc.)
    - User can populate the rest. All attributes are editable in the Project Wrapper



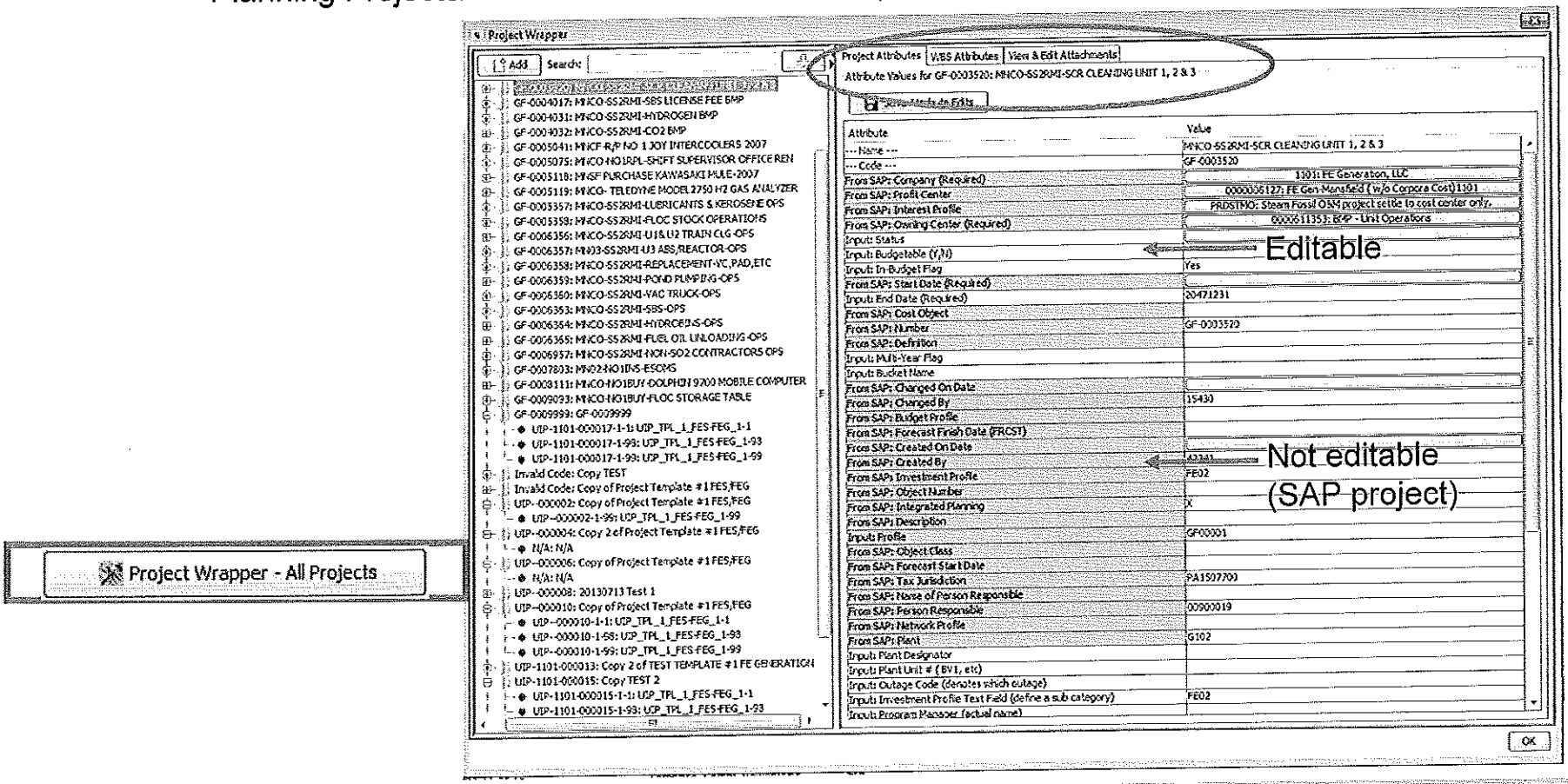


Creates the new project and copies WBS structure from the Template

Project Planning and Tracking - Project Wrapper

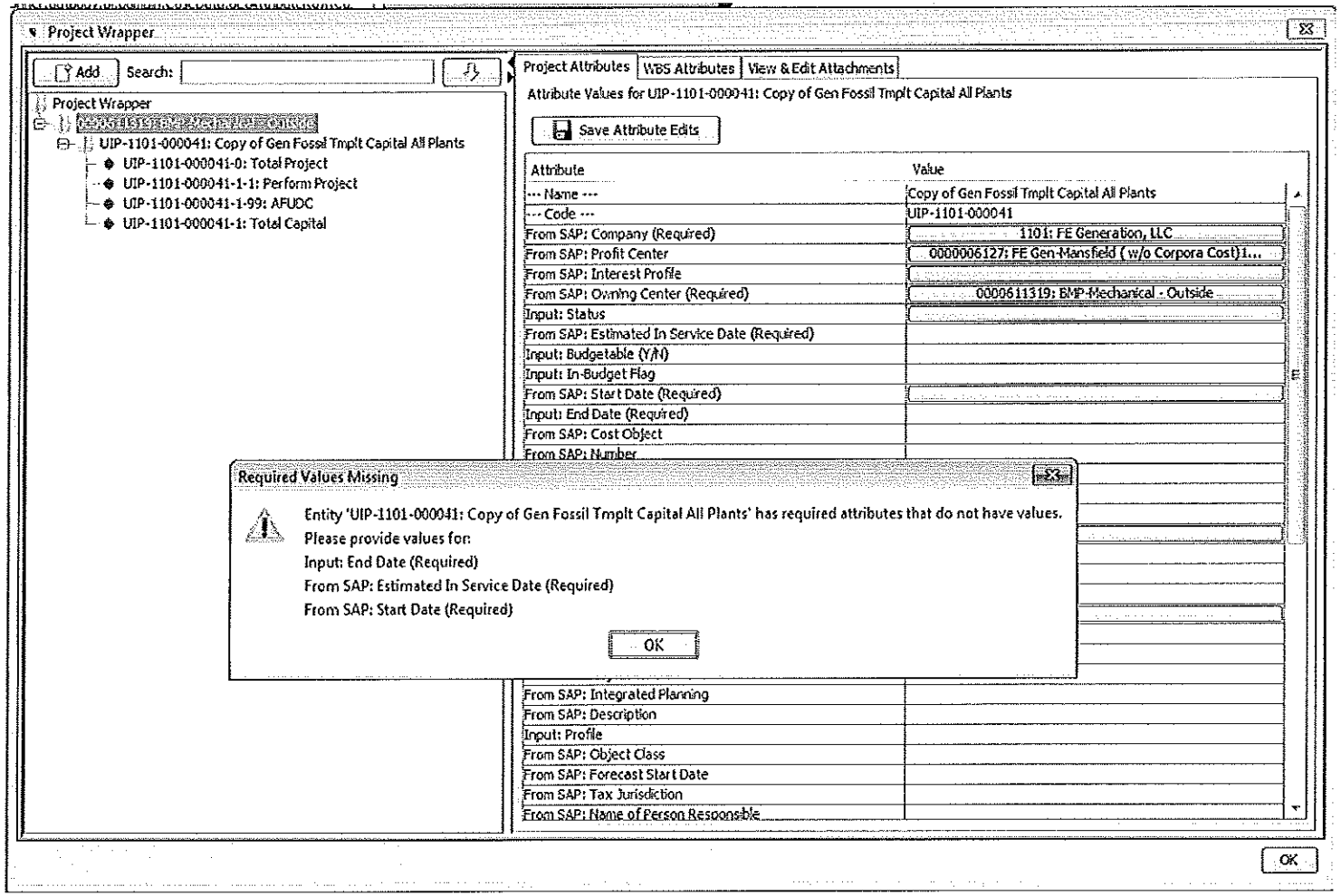
13

- Select the Project Wrapper button to open the Project Wrapper
  - Separate tabs for Project attributes and WBS attributes
  - Shows all attributes
    - Grayed out if you can not edit them
  - Rules for what can be edited and what cannot
    - Projects/WBS from SAP - attributes brought over and cannot be edited
    - Planning Projects/WBS - can edit all attributes (except ones populated by UIPlanner)



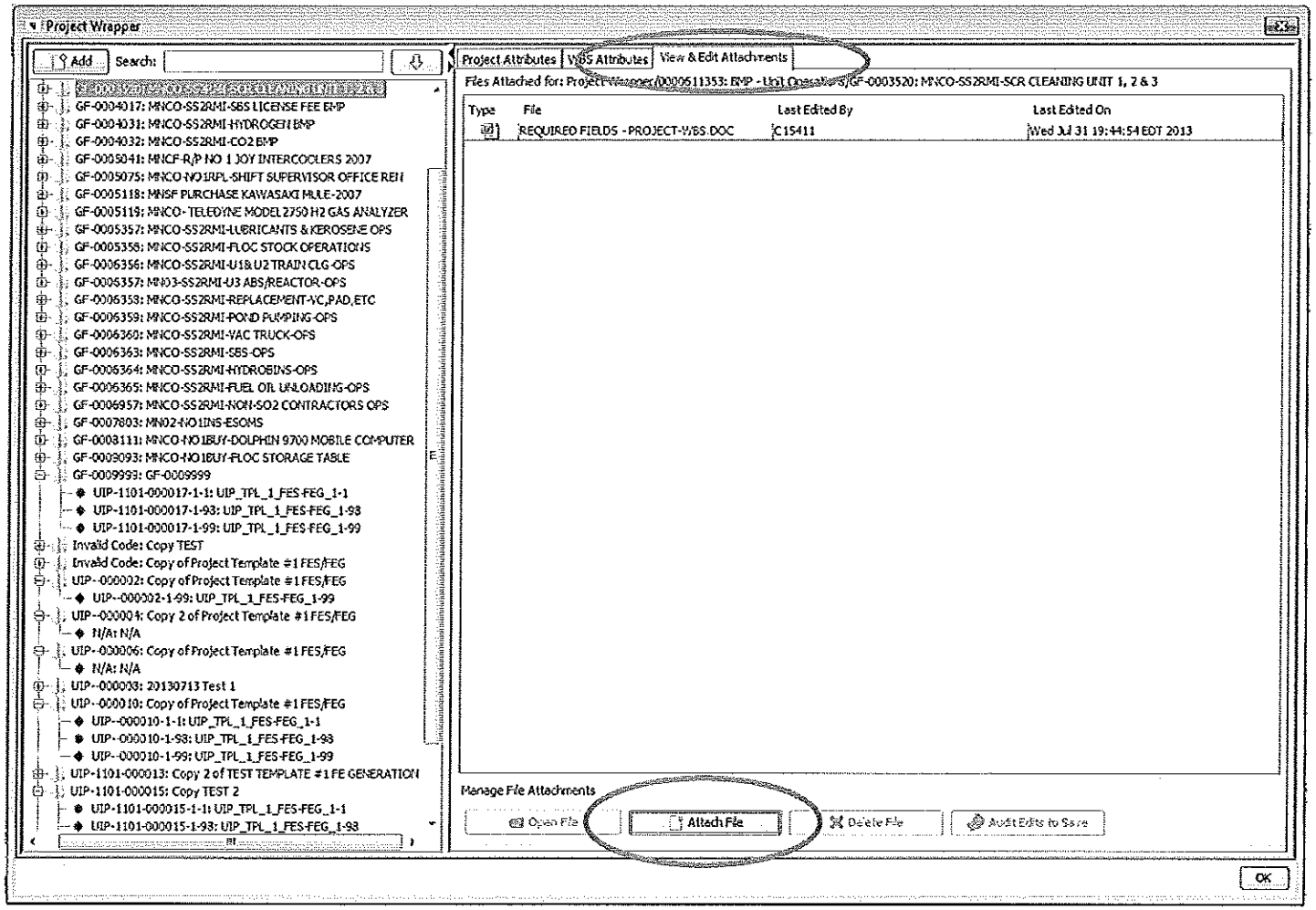
Project Planning and Tracking - Create New Project

14 • Certain fields for Projects and WBS are required
  - Needed in order to perform key calculations (closings, assessments, etc.)
  - Already populated for Projects/WBS from SAP
  - Need to make sure these are populated when you create a Planning Project

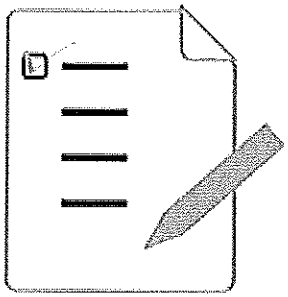


Project Planning and Tracking - Project/WBS Element Attachments

15 • Project Wrapper - Attachments
  - Select the View and Edit Attachment Tab
  - You can attach any document (DOC, XLS, etc.) to the project
  - Stored in the database and archived



Exercise #2 – Project Budget and Tracking



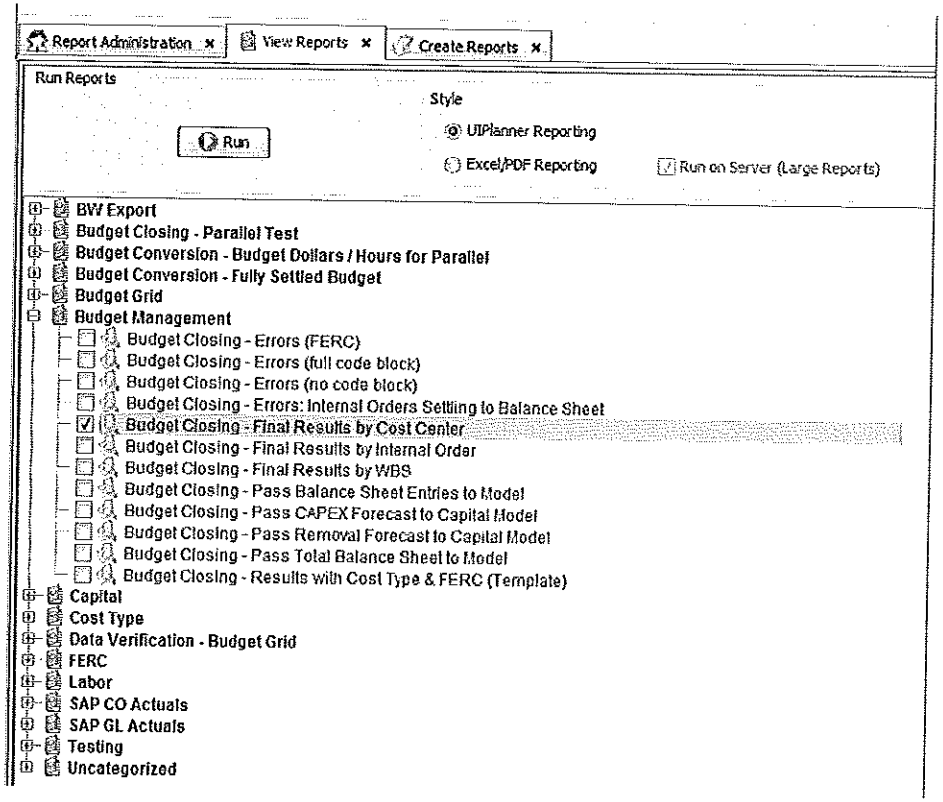
- Customize your Project Screen
  - Select attributes you would like to view
- Open the Budget Grid and make changes for a specific project
- Open Project Wrapper and view/edit project and WBS element attributes
- Export project to Excel pivot
- Create planning project using template

Reporting – Development and Usage

View Reports Screen

- Access View Reports screen by pressing Ctrl+F12 and typing "View Reports" or through a Report link from a Switchboard

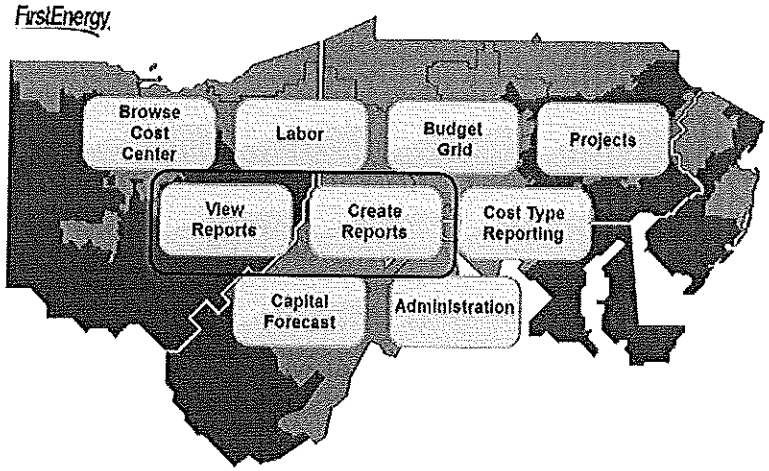
- Reports are published into thematic sections which can be expanded or collapsed by clicking on the +/- icon next to the section titles



View Reports screen

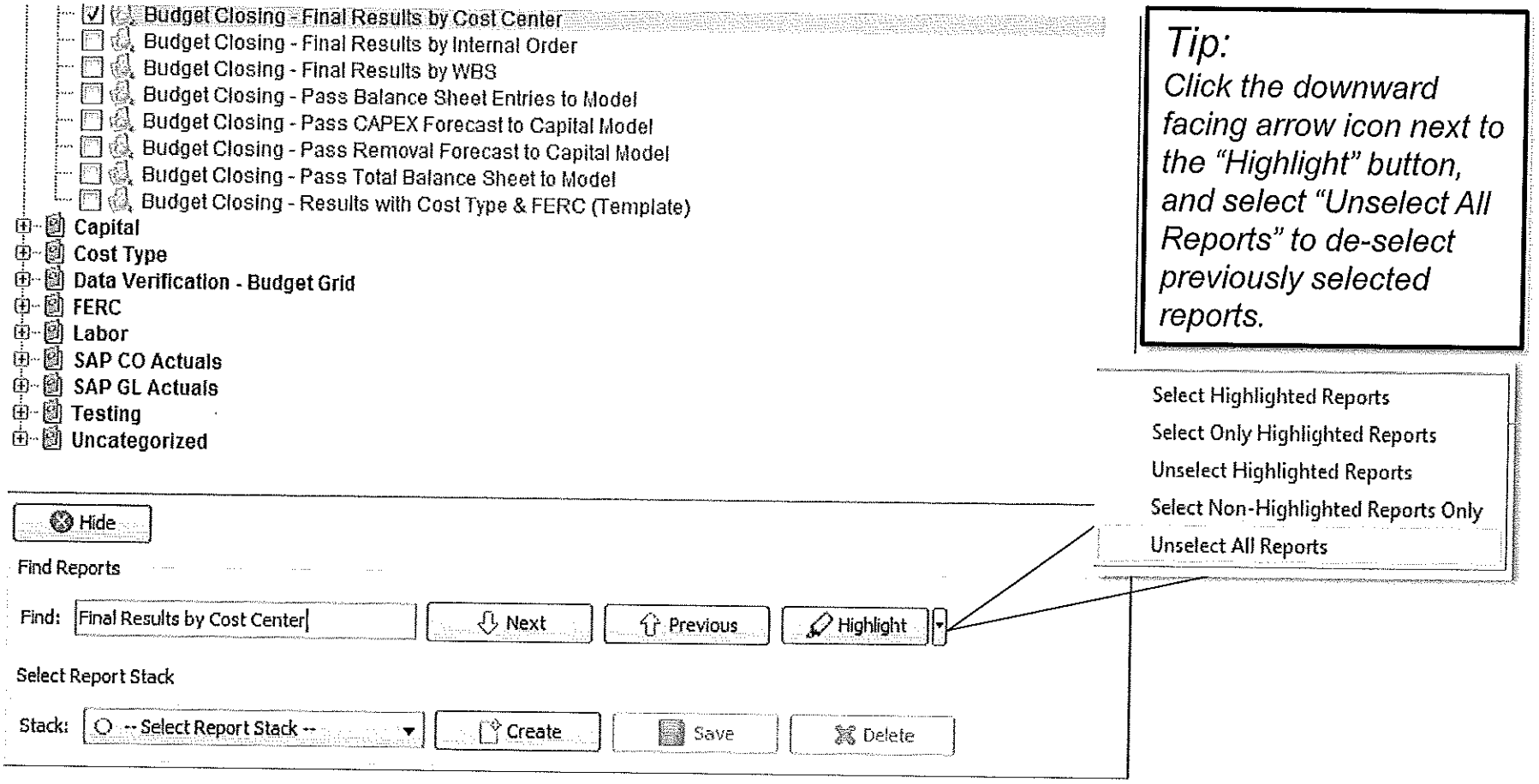
Tip:
Make sure that you have selected the correct Scenario before running reports.

Switchboard Reports



Finding Your Report

- Open Search controls by clicking the Search button at the bottom of the screen.
- Search by typing the name of your report. You can perform a "wildcard" search by adding "*" to your search terms. E.g. "*cost center*" will find any report that contains the phrase "cost center" within its name.
- Press the "Next" and "Previous" buttons to jump back and forth to the next results.

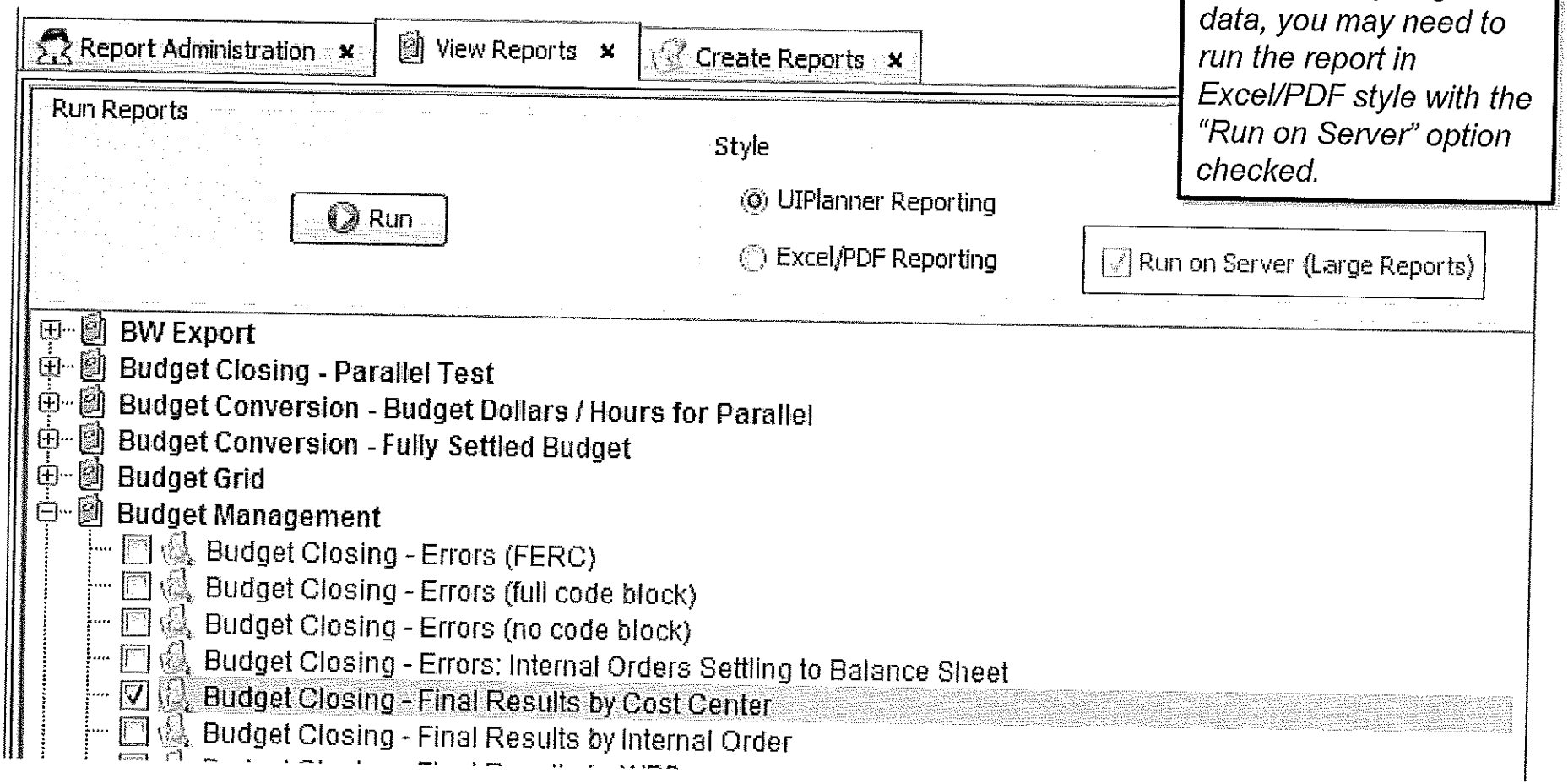


Tip:
Click the downward facing arrow icon next to the "Highlight" button, and select "Unselect All Reports" to de-select previously selected reports.

Running a Report from View Reports Screen

- Select the report style by checking the box next to the report and click Run
- Report Styles:
  - Excel/PDF for printing, saving locally, or if the data is too large.
  - UIPlanner style for the fully featured UIPlanner reporting screen

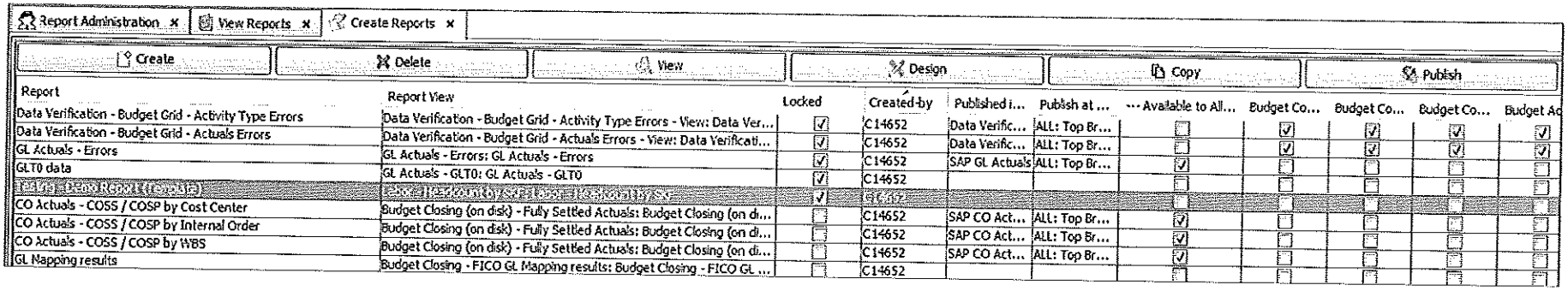
Tip:
For extremely large data, you may need to run the report in Excel/PDF style with the "Run on Server" option checked.



Create Reports Screen

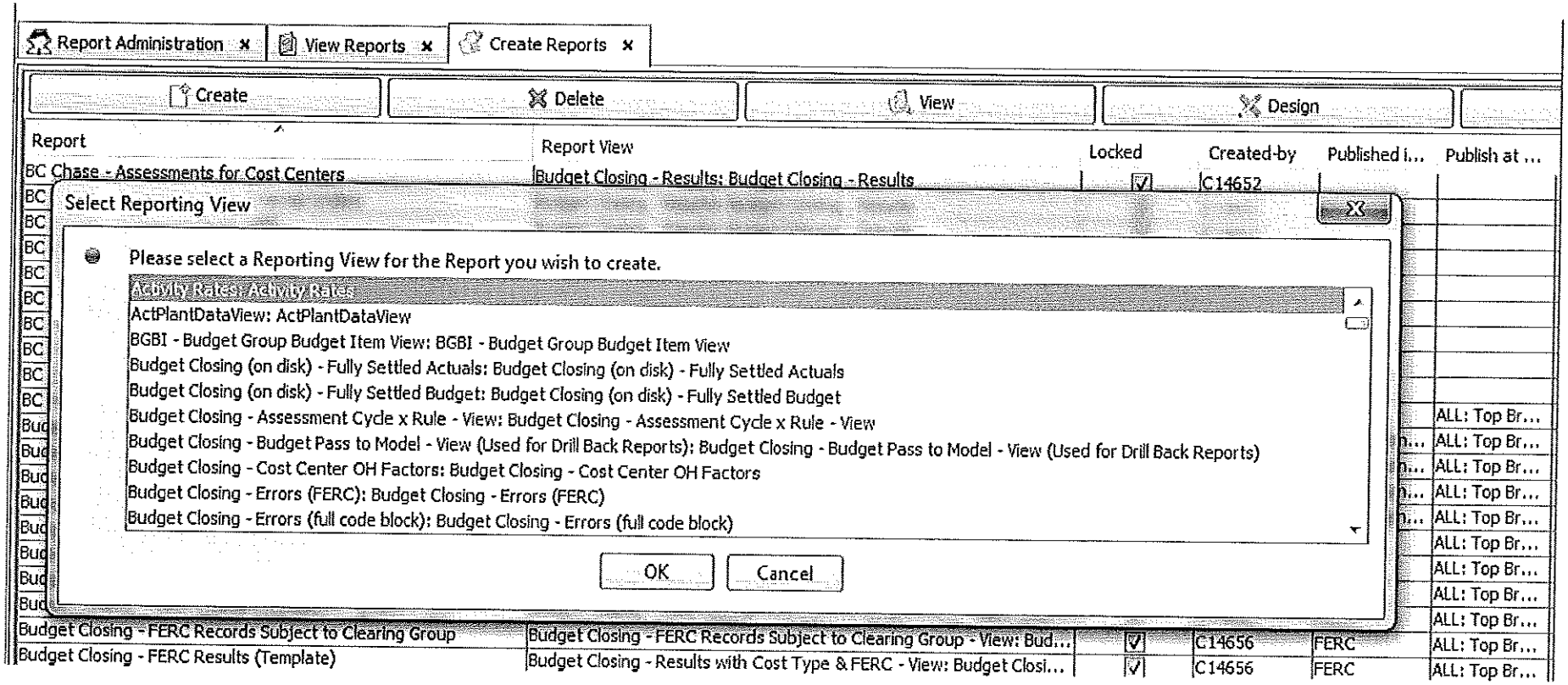
- The Create Reports screen is more flexible than the View Reports screen and allows for greater functionality enabling the user to develop and save versions of reports using these views.
- A Report Administrator can create a View on a set of data and enable features.
- Users can create, delete, view, design, copy, lock, and publish reports to reporting sections by User Role.

Create Reports screen

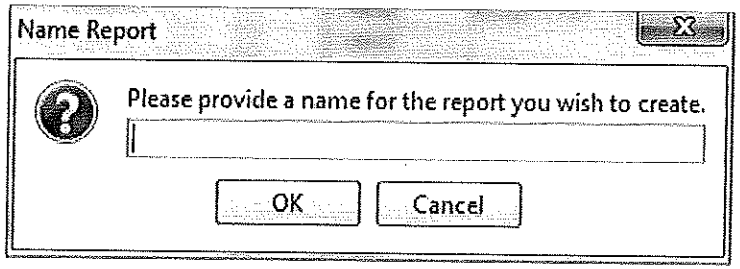


Create Reports Screen – Creating a Report from Scratch

- Click the "Create" button, you will be prompted to select the dataset View on which you wish to build a report.

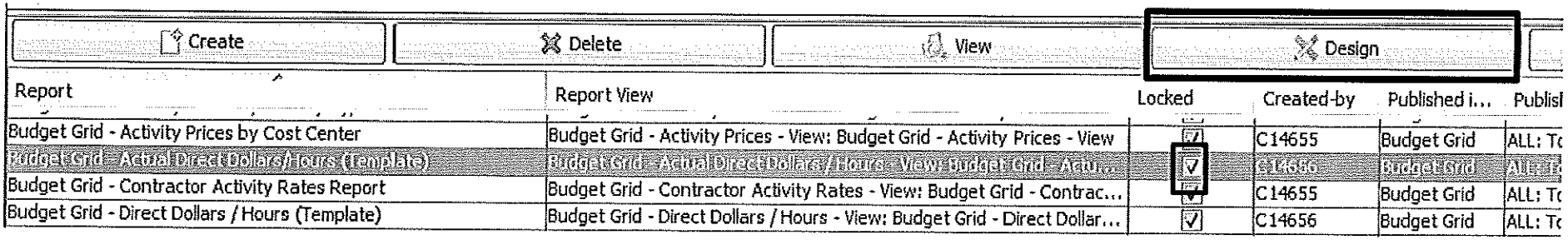


- Give your report a name but pay close attention to the preferred naming conventions to help organize your report.



Create Reports Screen - Creating a Report from a Template

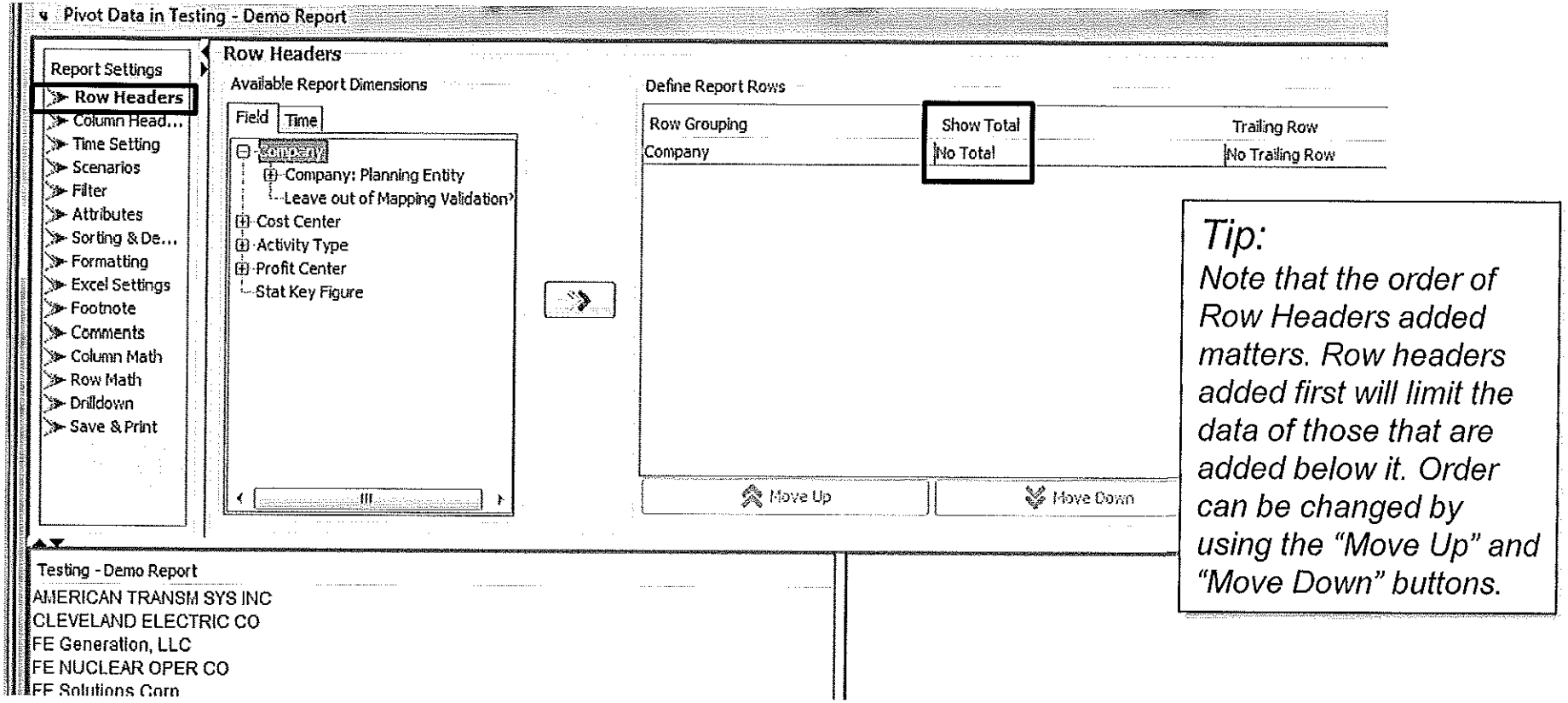
- Select the report from the list on the Create Report screen; should have "(Template)" in the name.
- Note that the Locked checkbox should be checked to prevent someone from accidentally saving their changes to the template itself.
- Press the Design button to bring up the report in design mode, which limits the data being returned to 200 records and allows for faster edits.
- The View button will return ALL records, which can be slow for very large datasets.



Report	Report View	Locked	Created-by	Published i...	Publisl
Budget Grid - Activity Prices by Cost Center	Budget Grid - Activity Prices - View: Budget Grid - Activity Prices - View	☑	C14655	Budget Grid	ALL: Tc
Budget Grid - Actual Direct Dollars/Hours (Template)	Budget Grid - Actual Direct Dollars / Hours - View: Budget Grid - Actu...	☑	C14656	Budget Grid	ALL: Tc
Budget Grid - Contractor Activity Rates Report	Budget Grid - Contractor Activity Rates - View: Budget Grid - Contrac...	☑	C14655	Budget Grid	ALL: Tc
Budget Grid - Direct Dollars / Hours (Template)	Budget Grid - Direct Dollars / Hours - View: Budget Grid - Direct Dollar...	☑	C14656	Budget Grid	ALL: Tc

Create Reports Screen – Adding Row Headers

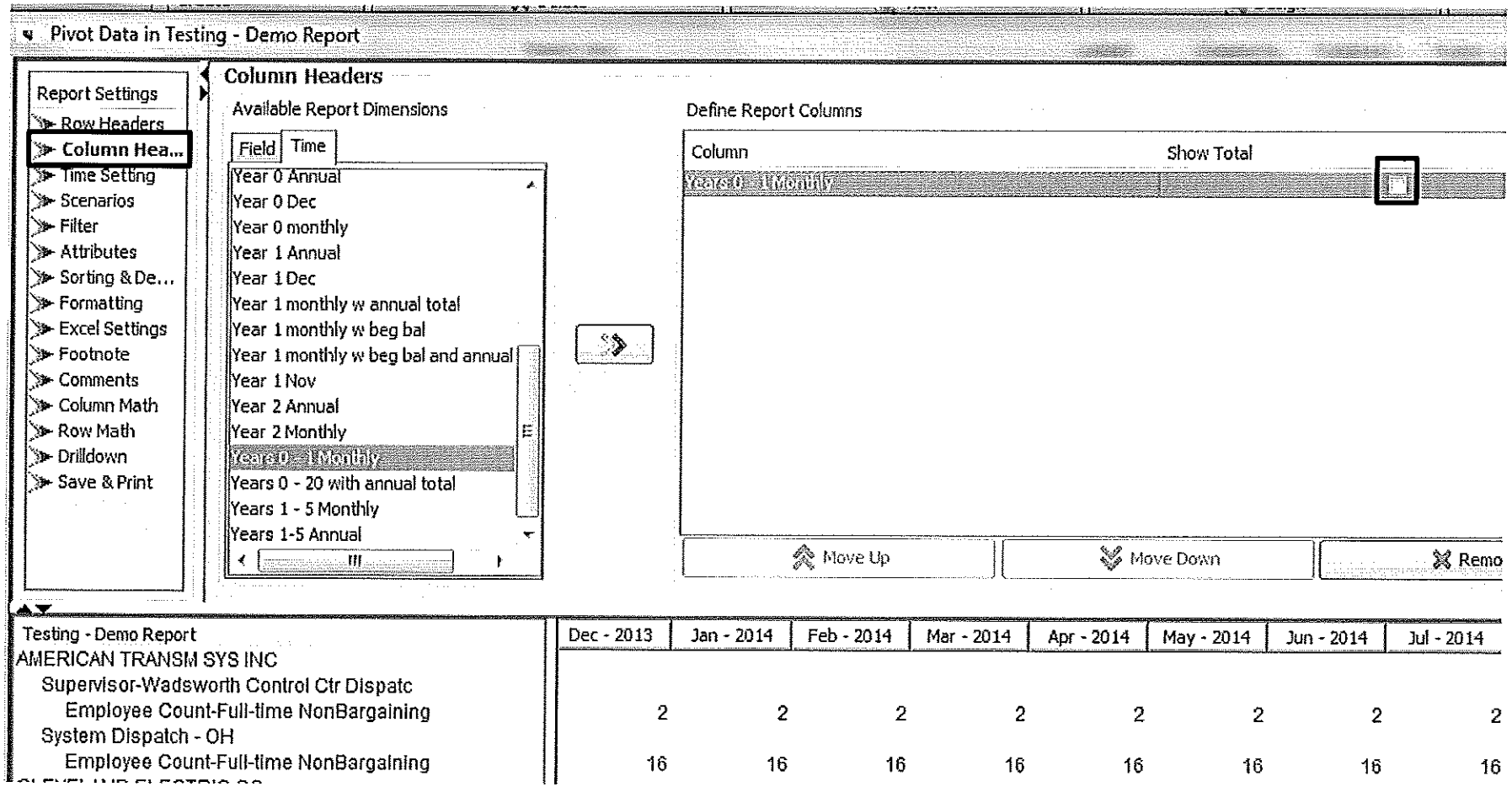
- Select "Row Headers" chevron from the "Report Settings" column to view available fields within the data set view. Highlight the field name and click the Arrow button to add the header to the report.
- You can expand some headers to select a header's attributes to be added. (e.g. Company Planning Entity)
- There is an option to add subtotals and trailing rows to each row added to the report by clicking the text under "Show Total" and "Trailing Row" labels.



Tip:
Note that the order of Row Headers added matters. Row headers added first will limit the data of those that are added below it. Order can be changed by using the "Move Up" and "Move Down" buttons.

Create Reports Screen – Adding Column Headers

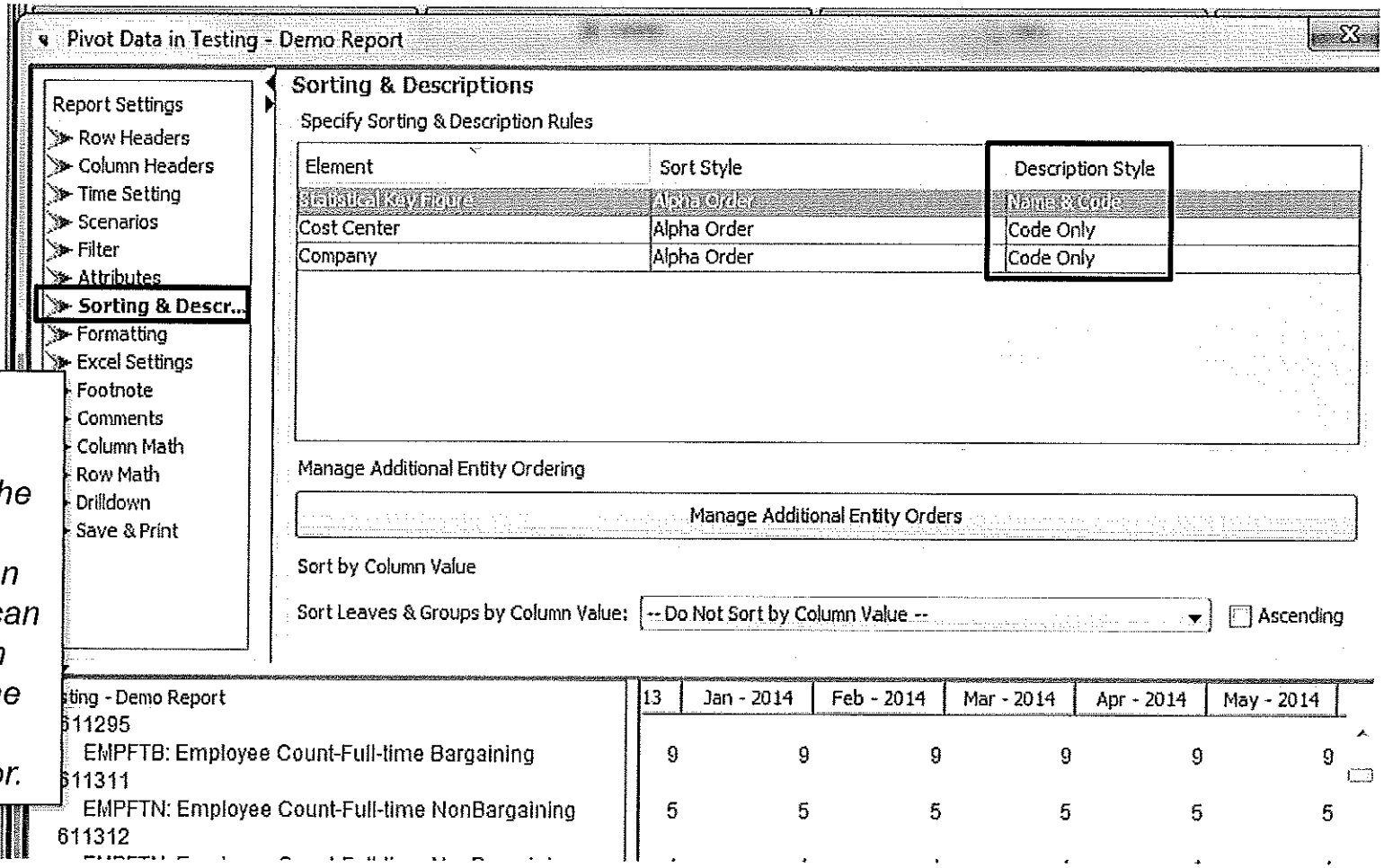
- Add Column Headers to view the time data.
- You can add additional columns to total the time period by checking the "Show Total" box.



Create Reports Screen – Changing Row Value Descriptions

- From the "Sorting and Descriptions" chevron, you can toggle a row header to display the "Name," "Code," or both values. E.g. The company code named "FE Solutions Corp" has a code of 1100, and either or both values can be displayed.

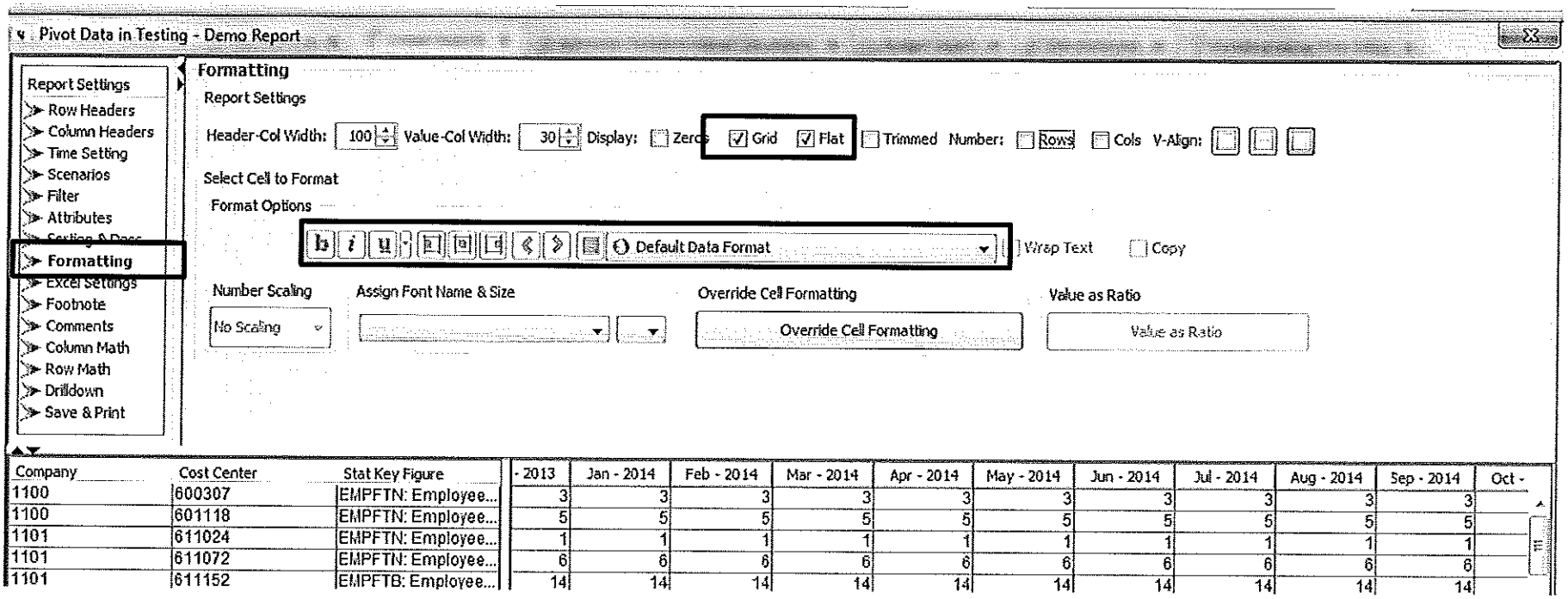
- The Filters in the following section work off of the "Code" values.



Tip:
All of the features in the Report Configuration (chevrons) can be turned on and off by the Report Administrator.

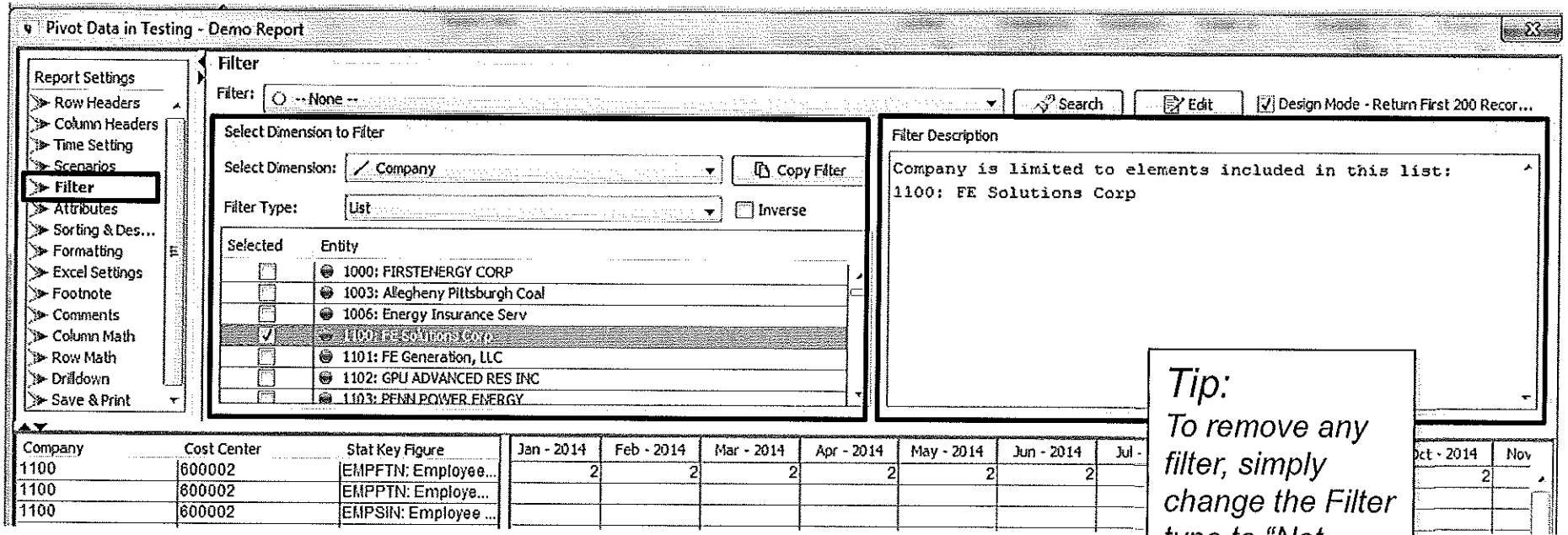
Create Reports Screen – Changing Formatting

- You can change the formatting to add grid lines, flatten out the row headers, etc...
- You can change the level of precision on the time data by clicking on a cell and changing the menu from "Default Data Format" to the desired format.



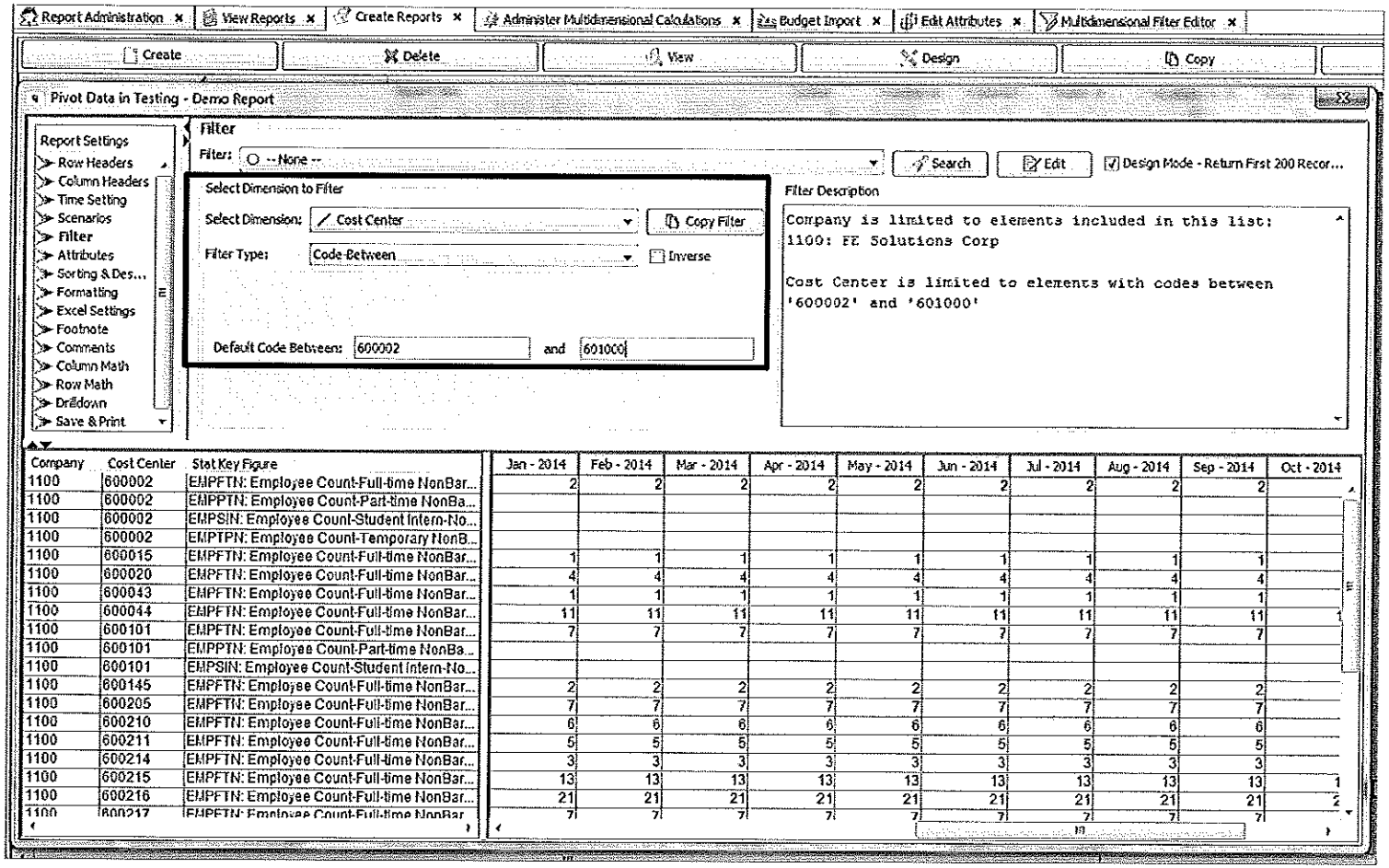
Create Reports Screen – Adding Filters (List Type Example)

- The Filter menu is for selecting Named Filters defined in the "Multidimensional Filter Editor" screen.
- There is a simple filter editor that allows you to select a dimension (one of the row headers) and select a filter type (list, tree, attribute, range, code-between, and code-like).
- The example pictured is an example of a List type filter on Company. Company 1100 is selected from the list and is described in the Filter Description box.



Create Reports Screen – Adding Filters (Code-Between Type Example)

- The example pictured is an example of a Code-Between type filter on Cost Center range. Cost Center Ranges from 600002 to 601000 is filtered.
- Note that the previous Company List type filter is still being applied

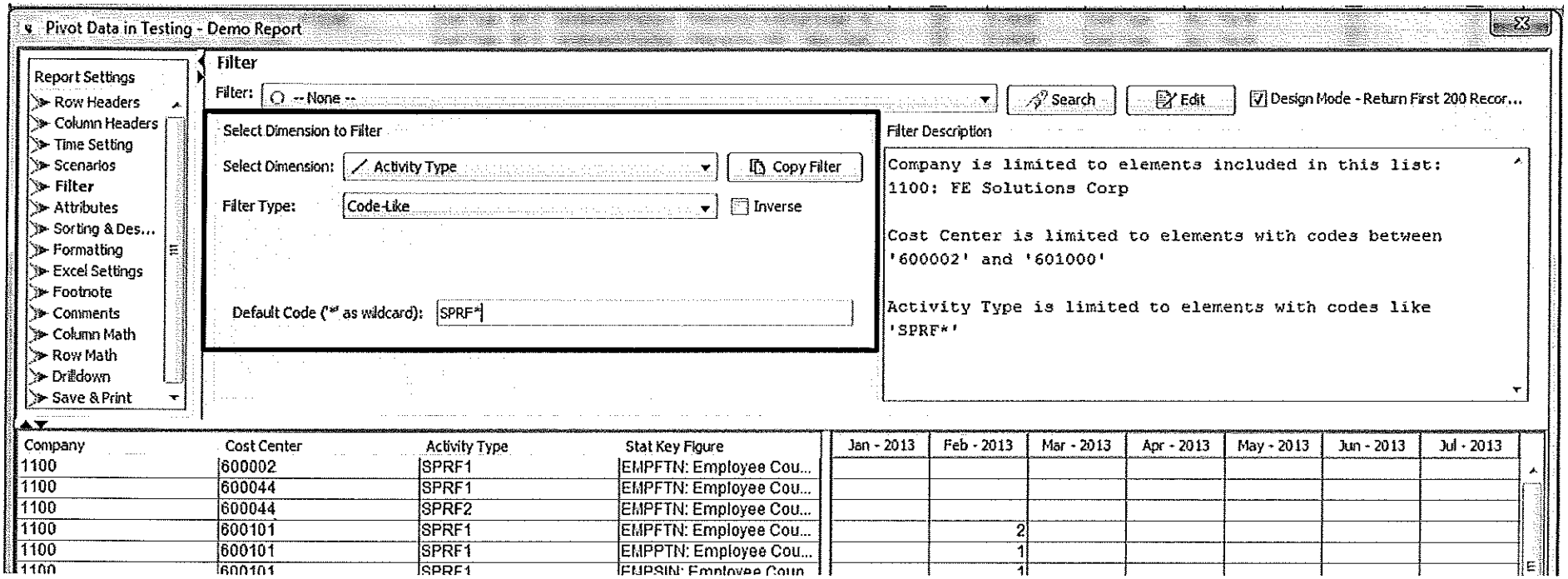


Tip:
The Filter Description window will show which filters are being applied.

Create Reports Screen – Adding Filters (Code-Like Type Example)

- The example pictured is an example of a Code-Like type filter on Activity Type range. Activity Types matching the pattern "SPRF*" are filtered.

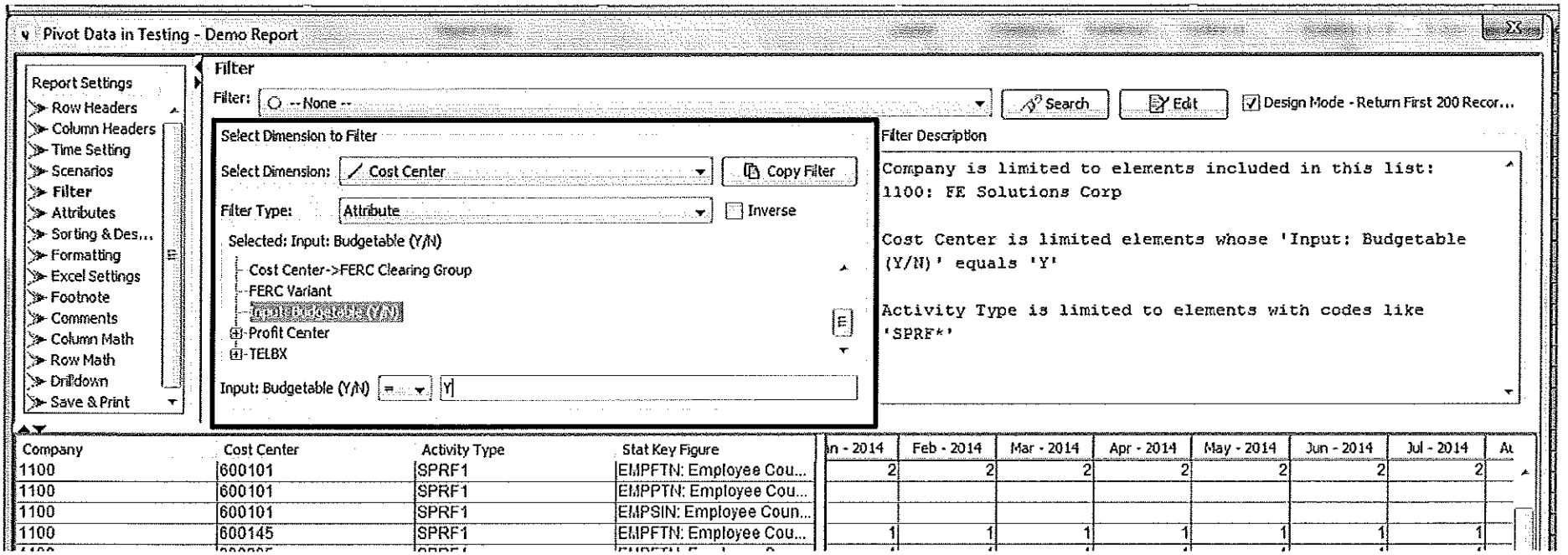
- The wildcard "*" denotes that any characters that <u>follow</u> "SPRF" will match the pattern. "SPRF1" and "SPRF2" match the pattern. "SPFR" would not match nor would "123SPFR" due to the placement of the wildcard character.



Create Reports Screen – Adding Filters (Attribute Type Example)

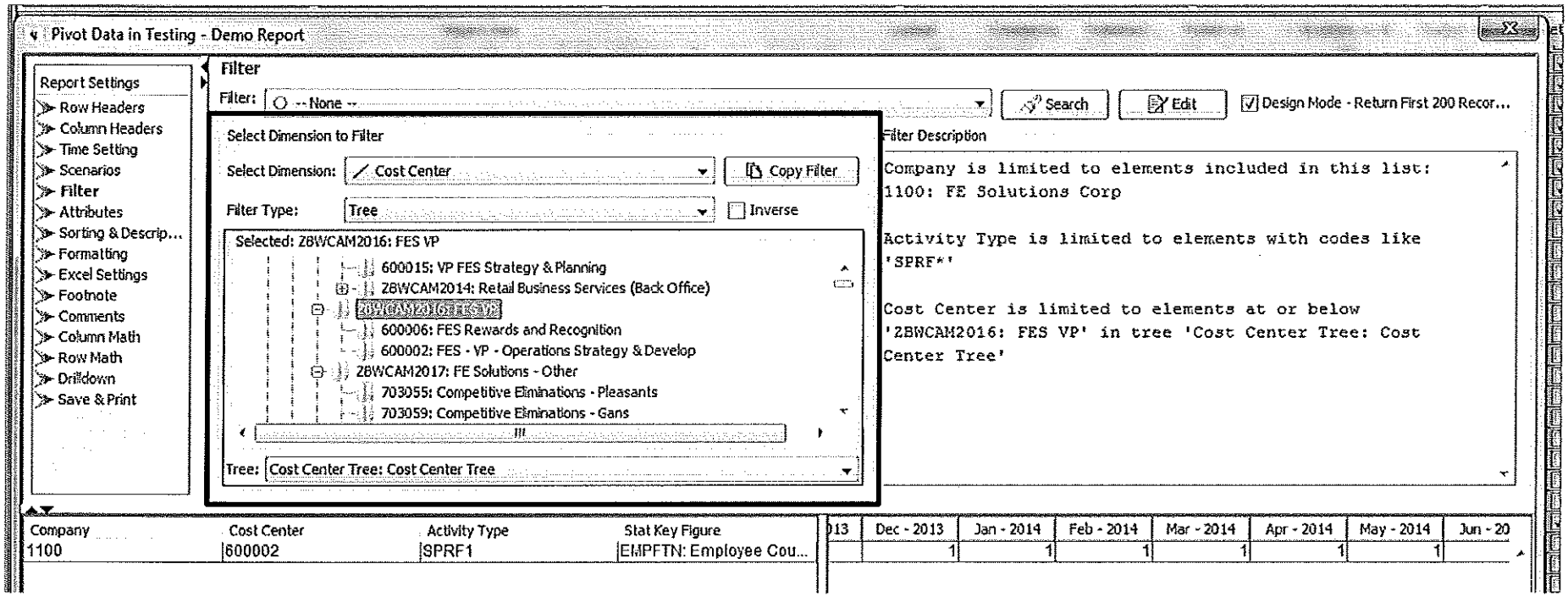
- The example pictured is an example of an Attribute type filter on Cost Center. The filter is checking against the value of the Cost Center's "Budgetable (Y/N)" attribute to only include Cost Centers where this attribute = "Y" It is also possible to use other operators such as >, >=, <, <=, or <> (not equal)

- Note that although the previous filters are still being applied, the Attribute filter on Cost Center has replaced the Cost Center Range type filter.



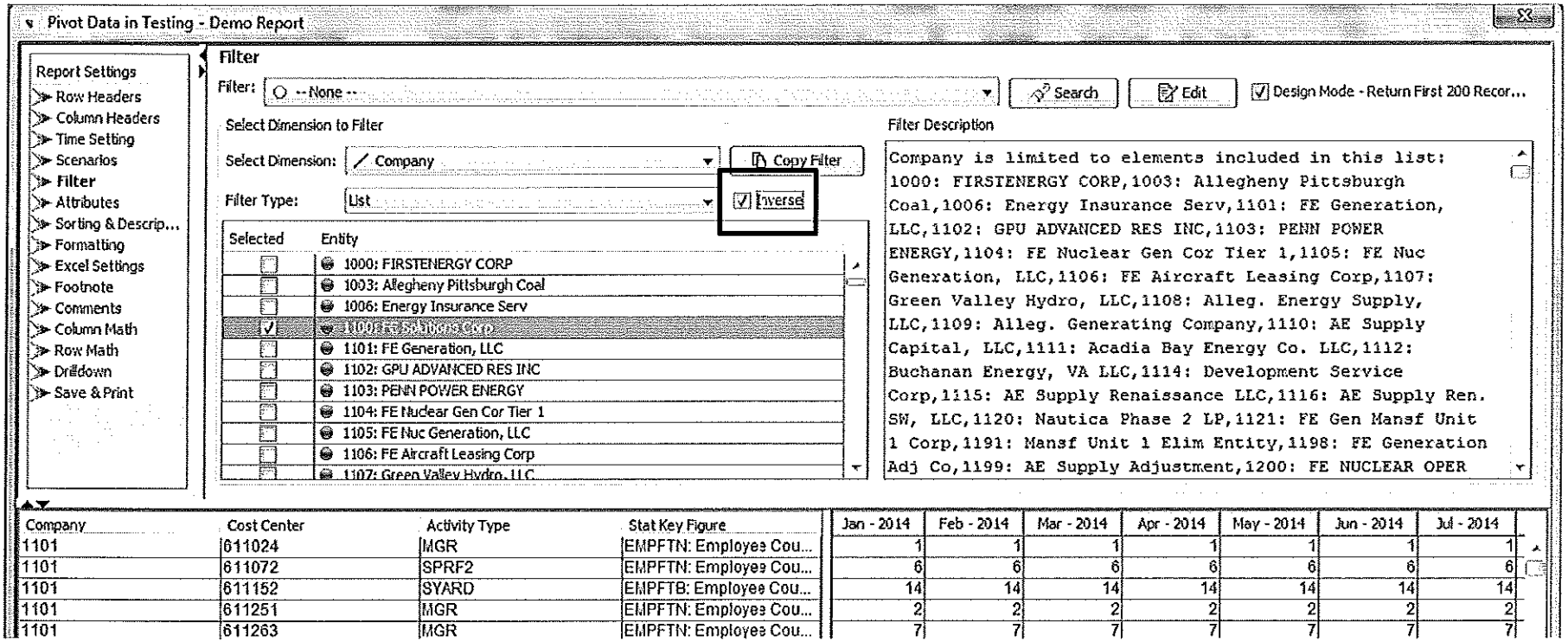
Create Reports Screen – Adding Filters (Tree Type Example)

- Tree filters can only be used on hierarchical elements like Cost Centers. The filter will include any element that appears at or below the selected node on the tree structure.
- Note that although the previous filters are still being applied, the Tree filter on Cost Center has replaced any other Cost Center filters.



Create Reports Screen – Inverse Filters

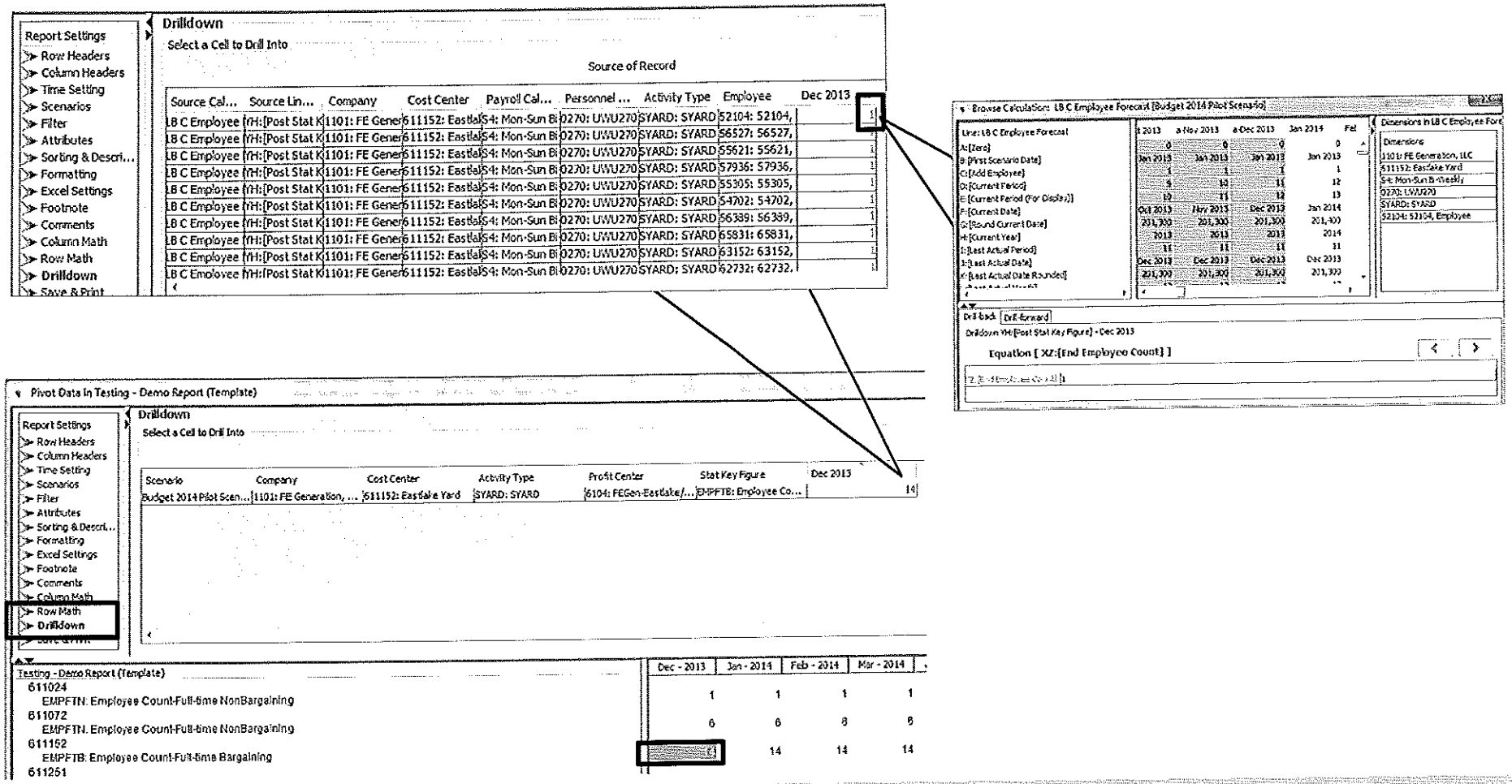
- For any Filter type, you can inverse the filter logic by checking the "Inverse" box. E.g. By inversing a Company List filter type set to "1100 - FE Solutions Corp", the results will include every company in the data set EXCEPT the company selected.



Create Reports Screen – Using Drill Down

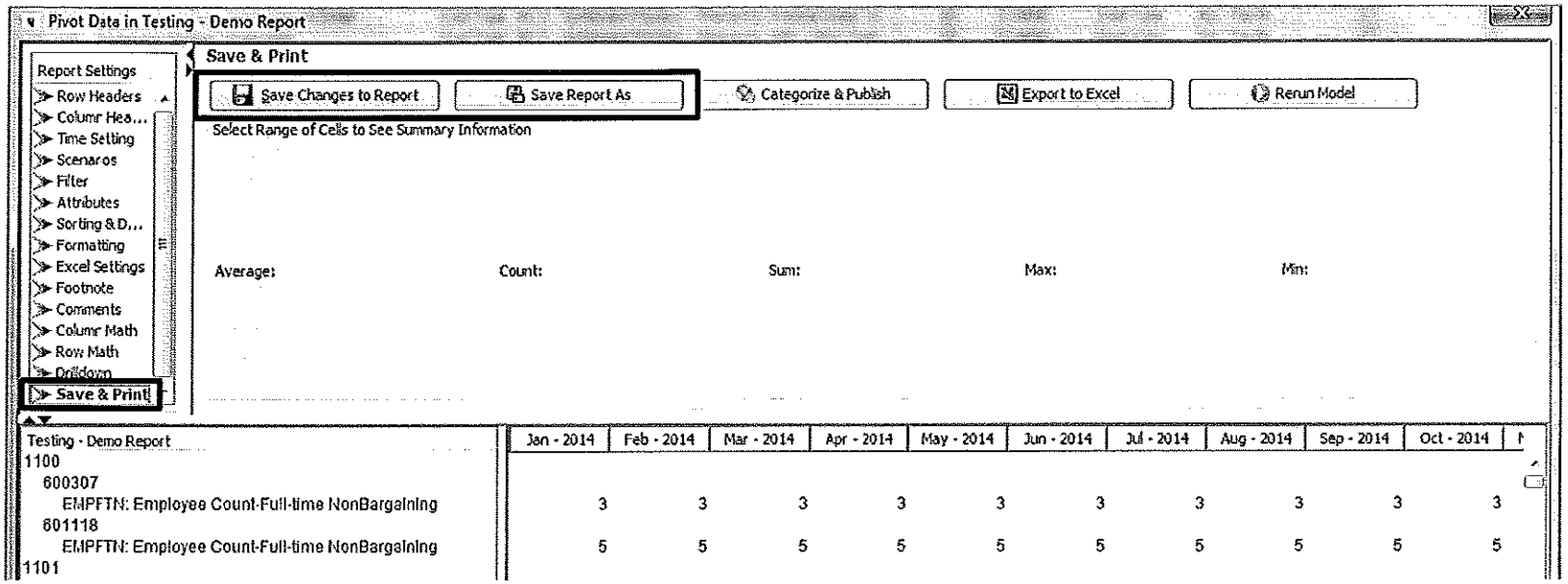
- By selecting the Drill Down chevron, you can drill down into the data and trace the data back to the calculation, formula applied, and constituent data.

- Highlight the data cell and click the linked values to keep drilling back to the data source.

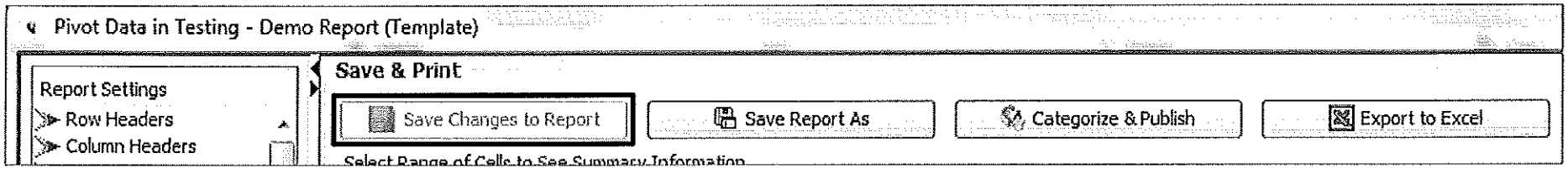


Create Reports Screen – Save and Print Screen

- If you are editing a previously configured report, you can save changes provided that the report is not locked and the "Save" function is enabled by the Report Administrator.



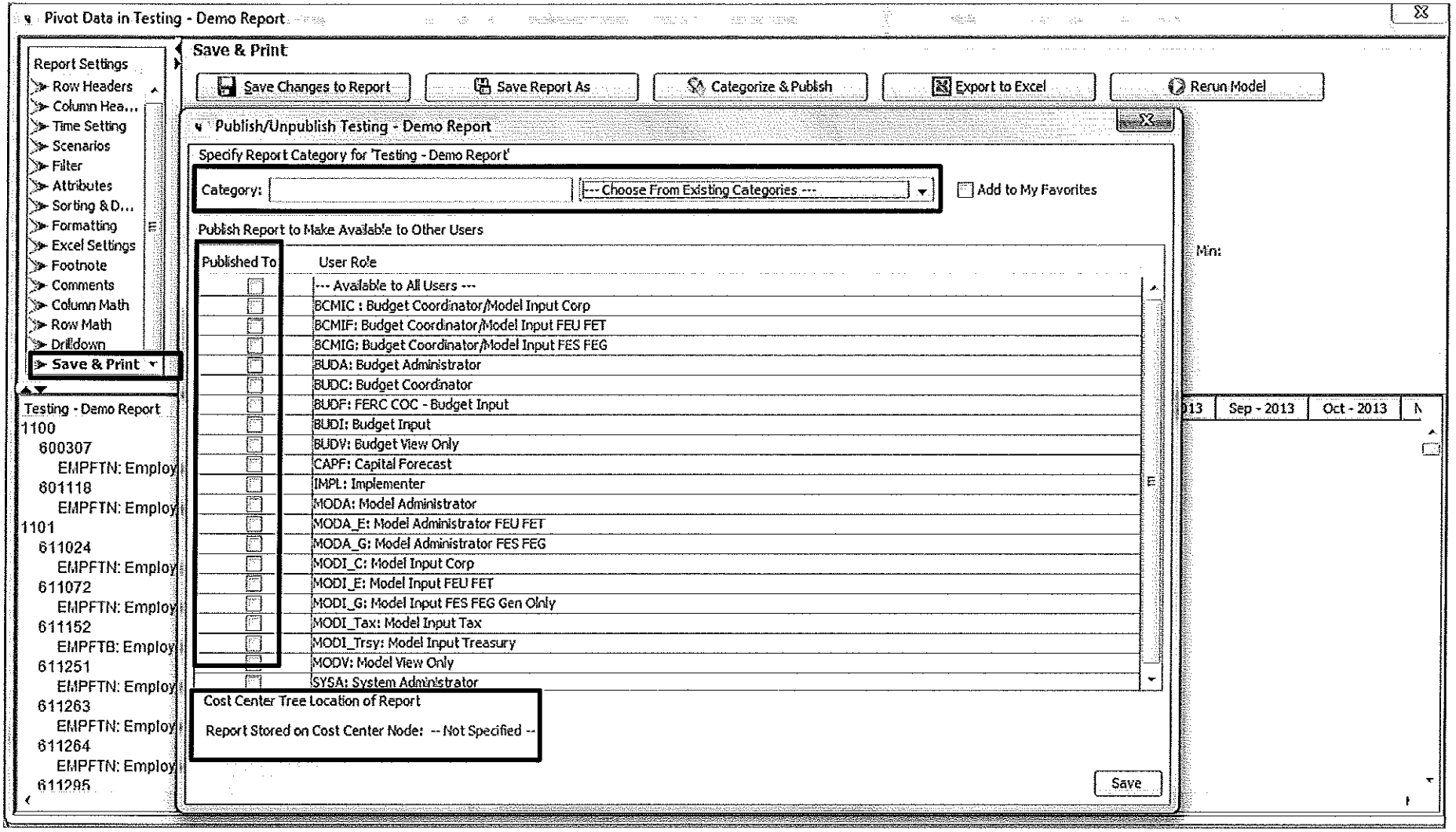
- If you are editing a locked "Template," use the "Save Report As." The "Save" button should be disabled for all Locked reports.



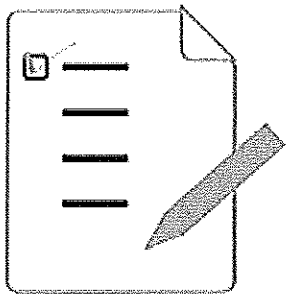
- Some reports will be Read-Only and all Save functionality will be disabled by the Report Administrators.

Create Reports Screen – Publishing Reports

- Push the "Categorize & Publish" button, and select or create a Category.
- Before saving, select the User Role checkboxes that should have access to the report.
- Be aware of your Cost Center Tree Context since your report will inherit it.



Exercise #3 – Reporting

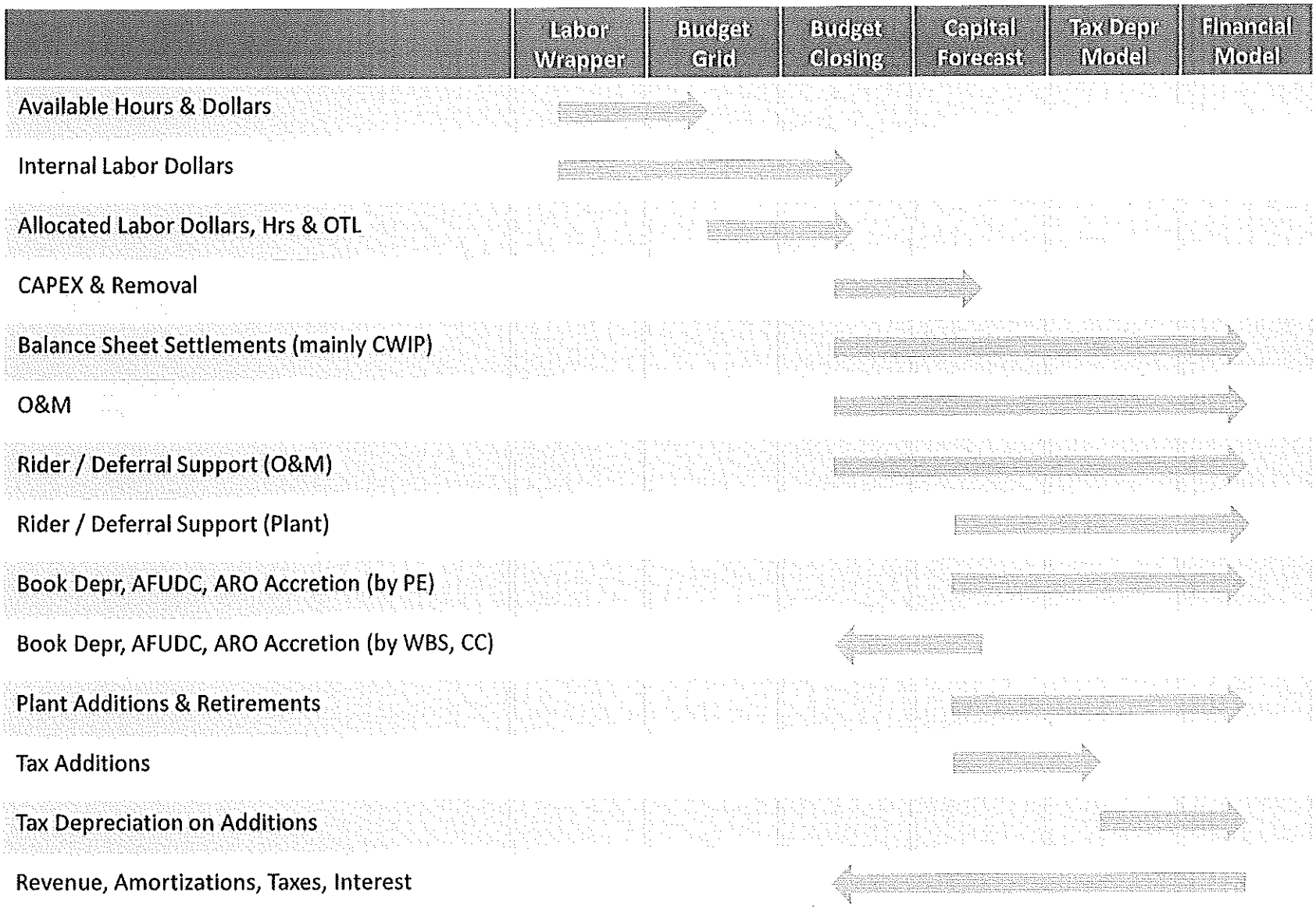


- Select View Reports and a category
  - Run various reports and review the output for selected areas

- Select Create Reports
  - Select dataset view
  - Create report name
  - Select the various reporting chevrons and customize your report
    - Add column headers
    - Change row value descriptions
    - Change formatting
    - Add a filter
    - Publish report

Data Flow

Data Flow

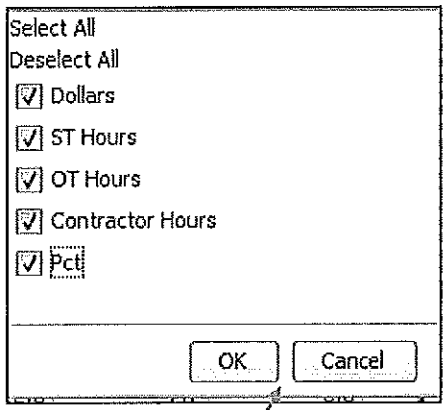

Labor Wrapper
Budget Grid
Budget Closing
Capital Forecast
Tax Depr Model
Financial Model
Available Hours & Dollars
Internal Labor Dollars
Allocated Labor Dollars, Hrs & OTL
CAPEX & Removal
Balance Sheet Settlements (mainly CWIP)
O&M
Rider / Deferral Support (O&M)
Rider / Deferral Support (Plant)
Book Depr, AFUDC, ARO Accretion (by PE)
Book Depr, AFUDC, ARO Accretion (by WBS, CC)
Plant Additions & Retirements
Tax Additions
Tax Depreciation on Additions
Revenue, Amortizations, Taxes, Interest

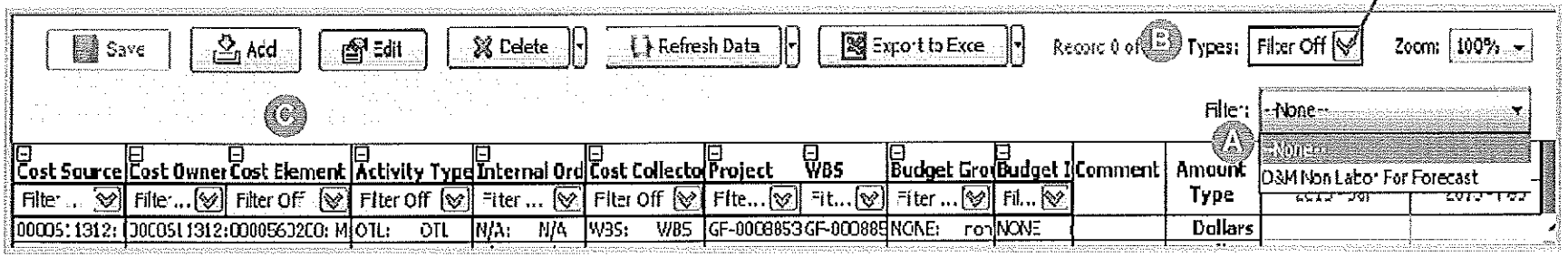
Multi-Year Plan / Forecast

Multi-Year Plan / Forecast Overview

Multi-Year Forecast Requirements

- Ability to properly run the budget close process for years 1-5 (cost collector detail needed for this to occur)
- Allows users the ability to develop a detailed forecast or adjust at a summary level
- Ability for System Administrator to set global assumptions





Filters available to target specific areas to change

A. Filter on common categories (e.g. Cost Element groupings, O&M other than labor, Labor, etc.)
B. Filter on dollars or hours
C. Grid filters for each code block data field (specific Cost Elements, specific Cost Source, etc)

Multi-Year Plan / Forecast Options

Available options to perform multi-year plan/forecast

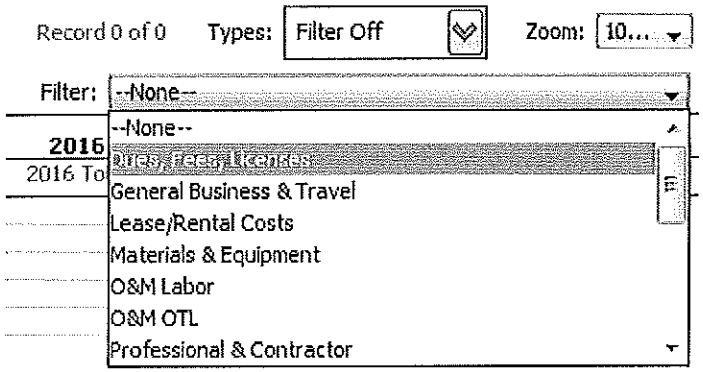
Detailed

- Labor automatically calculates for planning horizon
- Copy current year grid to Excel for entire group or specific Cost Centers (years 1-5)
- Make detailed adjustments at any level in Excel
- Copy data back to grid (grid validates)
- User can then use the "column total" feature in the grid to adjust the forecast

Summary

- Labor automatically calculates for planning horizon
- Utilize available filters
  - Using the cost element hierarchy, users can easily select the cost element node and then make adjustments to the related code block (e.g. O&M non-capital) or create filters based on the income statement groups
- User can then use the "column total" feature in the grid to adjust the forecast

Users can view filters in the Budget Grid by using the drop down to select a group



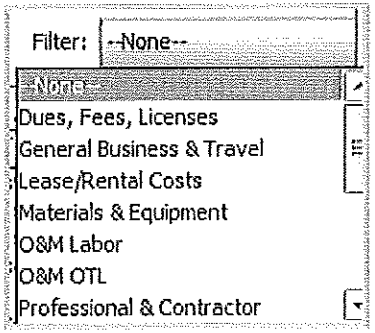
Current and Multi-Year Forecast Filters

Current and Multi-Year Forecast Filters

- Grid filters are available to assist with the current and multi-year forecast process
- Filters utilize various nodes within the internal income statement cost element hierarchy
  - The cost element hierarchy is maintained in SAP
  - Transaction KAH3 – Cost Element Group = ZBWIIS0000
- Additional filters include leveraging attributes on master data
  - Projects and WBS Elements
- When a grid filter is selected, only the data that matches the filter will display
  - Example: Labor – only displays grid combinations that contain labor cost elements



- Budget Grid
  - Select a grid filter
  - Edit on screen or Excel



Available Grid Filters

O&M OTL Filters

- **O&M OTL**
  - ZBWIIS2192
- **Dues, Fees Licenses**
  - ZBWIIS2193
- **General Business & Travel**
  - ZBWIIS2202
- **Lease/Rental Costs**
  - ZBWIIS2198
- **Materials & Equipment**
  - ZBWIIS2214
- **Professional & Contractor**
  - ZBWIIS2220
- **Tree Trimming Total**
  - ZBWIIS2232
- **Uncollectible Expense**
  - ZBWIIS2242

O&M Labor Filter

- **O&M Labor**
  - ZBWIIS2161

Project Filters

Project Definition

Investment Profile

- Project = Mandatory (FE01)
- Project – Maintain (FE02)
- Project = Improve (FE03)
- Project = Value (FE04)

Available Grid Filters

WBS Element Filters

- **Interest Profile = Blanket**

ACCTWO	Blkt Accounting Orders 107345
COMMEQB	Blkt Comm Equipment 107328 / 108529
CORPB	Blkt Corporate Items - Manual Settlement Rules
DATAPRB	Blkt Data Process Equip 107326 / 108532
DLLANDB	Blkt Dist Lines Site & R of W 107343 / 108527
DLOHB	Blkt Dist Lines OH 107314 / 108527
DLUGB	Blkt Dist Lines UG 107315 / 108527
DSTOTHB	Blkt Dist Other 107319 / 108527
DSTSUBB	Blkt Dist Sub 107313 / 108527
ESIPOHB	Blkt Street Lighting ESIP OH 107320 / 108528
ESIPUGB	Blkt Street Lighting ESIP UG 107321 / 108528
GENOTHB	Blkt Other General Plant 107329 / 108529
GENPLTB	Blkt Office Furn,Tools & Test Eq 107323 / 108529
GNLANDB	Blkt General Plant Site & R of W 107344 / 108529
JCOTHB	Blkt Jobbing & Contract Other 186001
JOBCONB	Blkt Jobbing & Contract 186001
MTRTRFB	Blkt Project Meters Only 107318 / 108527
MUTASTB	Blkt Mutual Assistance Storms 186789
NONULB	Blkt Non-Utility Land 121341 / 122302
NONUTFB	Blkt Non-Utility Fiber Optics 121342 / 122303
NONUTLB	Blkt Non-Utility Property 121341 / 122302
NONUTOB	Blkt Non-Utility Other 121341 / 122302
OTHLNDB	Blkt Other Site & R of W GEN ONLY 107339 / 108524
PRDHYDB	Hydro Blanket Proj 107303 / Removal Use Ferc CC
PRDNUCB	Nuclear Blanket Proj 107301 / Removal Use Ferc CC
PRDOTHB	Peaker Blanket Proj 107302 / Removal Use Ferc CC
PRDSTMB	Steam Fossil Blanket Proj 107300 / Removal Use Fe
PSIB	Blkt Preliminary Survey & Investigation 183000
PWROPER	Blkt Power Operated Equipment 107325 / 108531
SLOHB	Blkt Street Lighting Overhead 107316 / 108527
SLUGB	Blkt Street Lighting Underground 107317 / 108527
STRUCTB	Blkt Buildings & Related Projects 107322 / 108529
SUBBLLB	Blkt Billings to Subsidiaries 186415
TEMPB	Blkt Temporary Facilities 185000
TL138B	Blkt Transmission Lines 138KV 107308 / 108526
TL23KVB	Blkt Transmission Lines 23KV 107305 / 108526
TL34KVB	Blkt Transmission Lines 34KV 107306 / 108526
TL69KVB	Blkt Transmission Lines 69KV 107307 / 108526
TLLANDB	Blkt Trans Lines Site & R of W 107341 / 108526
TLO115B	Blkt Project TX OH Lines 115KV 107000 / 108000
TLO11B	Blkt Project TX OH Lines 11.8KV 107000 / 108000
TLO13B	Blkt Project TX OH Lines 13.8KV 107000 / 108000
TLO230B	Blkt Project TX OH Lines 230KV 107000 / 108000
TLO25B	Blkt Project TX OH Lines 25KV 107000 / 108000
TLO345B	Blkt Project TX OH Lines 345KV 107000 / 108000
TLO36B	Blkt Project TX OH Lines 36KV 107000 / 108000
TLO46B	Blkt Project TX OH Lines 46KV 107000 / 108000
TLO500B	Blkt Project TX OH Lines 500KV 107000 / 108000
TLO765B	Blkt Project TX OH Lines 765KV 107000 / 108000
TLOTHB	Blkt Transmission Lines Other 107311 / 108526
TLU115B	Blkt Project TX URD Lines 115KV 107000 / 108000
TLU11B	Blkt Project TX URD Lines 11.8KV 107000 / 108000
TLU138B	Blkt Project TX URD Lines 138KV 107000 / 108000
TLU13B	Blkt Project TX URD Lines 13.8KV 107000 / 108000
TLU230B	Blkt Project TX URD Lines 230KV 107000 / 108000
TLU23B	Blkt Project TX URD Lines 23KV 107000 / 108000
TLU25B	Blkt Project TX URD Lines 25KV 107000 / 108000
TLU345B	Blkt Project TX URD Lines 345KV 107000 / 108000
TLU34B	Blkt Project TX URD Lines 34KV 107000 / 108000
TLU36B	Blkt Project TX URD Lines 36KV 107000 / 108000
TLU46B	Blkt Project TX URD Lines 46KV 107000 / 108000
TLU500B	Blkt Project TX URD Lines 500KV 107000 / 108000
TLU69B	Blkt Project TX URD Lines 69KV 107000 / 108000
TLU765B	Blkt Project TX URD Lines 765KV 107000 / 108000
TLUGB	Blkt Trans Lines UG <69KV 107310 / 108526
TRANSB	Blkt Transportation Equipment 107324 / 108530
TRANSFB	Blkt Project Transformers Only 107318 / 108527
TRANUGB	Blkt Trans Lines UG <69KV 107310 / 108526
TRNSUBB	Blkt Transmission Substations 107304 / 108526
GENPLOM	GENERAL PLANT OPERATIONS % MAINTENANCE

Available Grid Filters

WBS Element Filters

- **Interest Profile = Program**

COMMEQP	Prgm Comm Equipment 107328 / 108529
DLLANDP	Prgm Dist Lines Site & R of W 107343 / 108527
DLOHP	Prgm Dist Lines OH 107314 / 108527
DLUGP	Prgm Dist Lines UG 107315 / 108527
DSTOTHP	Prgm Dist Other 107319 / 108527
DSTSUBP	Prgm Dist Sub 107313 / 108527
ESIPOHP	Prgm Street Lighting ESIP OH 107320 / 108528
ESIPUGP	Prgm Street Lighting ESIP UG 107321 / 108528
GENOTHP	Prgm Other General Plant 107329 / 108529
GNLANDP	Prgm General Plant Site & R of W 107344 / 108529
MTRTRFP	Prgm Project Meters Only 107318 / 108527
SLOHP	Prgm Street Lighting Overhead 107316 / 108527
SLUGP	Prgm Street Lighting Underground 107317 / 108527
TEMPP	Prgm Temporary Facilities 185000
TL23KVP	Prgm Transmission Lines 23KV 107305 / 108526
TL34KVP	Prgm Transmission Lines 34KV 107306 / 108526
TL69KVP	Prgm Transmission Lines 69KV 107307 / 108526
TLLANDP	Prgm Trans Lines Site & R of W 107341 / 108526
TLOTHP	Prgm Transmission Lines Other 107311 / 108526
TLUGP	Prgm Trans Lines UG <69KV 107310 / 108526
TRANSFP	Prgm Project Transformers Only 107318 / 108527
TRANSP	Prgm Transportation Equipment 107324 / 108530
TRANUGP	Prgm Trans Lines UG <69KV 107310 / 108526
TRNSUBP	Prgm Transmission Substations 107304 / 108526

Available Grid Filters

WBS Element Filters

- **Interest Profile = Specific**

INTANG	Intangible Plant 107346
TXOMOH	Trans O&M - Overhead Lines 563 / 571
BLGLEAS	Spc Leased Bldg & Related Equip 107327 / 108529
COMMEQS	Spc Comm Equipment 107328 / 108529
CORPS	Spc Corporate Items - Manual Settlement Rules
DATAPRS	Spc Data Process Equip 107326 / 108532
DEFSTMS	Spc New Jersey Storm Deferral 182316
DLLANDS	Spc Dist Lines Site & R of W 107343 / 108527
DLOHS	Spc Dist Lines OH 107314 / 108527
DLUGS	Spc Dist Lines UG 107315 / 108527
DSLANDS	Spc Dist Sub Site & R of W 107342 / 108527
DSTOTHS	Spc Dist Other 107319 / 108527
DSTSUBS	Spc Dist Sub 107313 / 108527
ESIPOHS	Spc Street Lighting ESIP OH 107320 / 108528
ESIPUGS	Spc Street Lighting ESIP UG 107321 / 108528
GENOTHS	Spc Other General Plant 107329 / 108529
GNLANDS	Spc General Plant Site & R of W 107344 / 108529
JCOTHS	Spc Jobbing & Contract Other 186001
JOBCONS	Spc Jobbing & Contract 186001
MTRTRFS	Spc Project Meters Only 107318 / 108527
MUTASTS	Spc Mutual Assistance Storms 186789
NFLEAS	Spc Nuclear Fuel Capital Lease 120600
NONULS	Spc Non-Utility Land 121341 / 122302
NONUTFS	Spc Non-Utility Fiber Optics 121342 / 122303
NONUTLS	Spc Non-Utility Property 121341 / 122302
NONUTOS	Spc Non-Utility Other 121341 / 122302
NUCFLS	Spc Nuclear Fuel 120100
NUCLDS	Spc Nuclear Site & R of W 107338 / 108523
OTHLNDS	Spc Other Site & R of W GEN ONLY 107339 / 108524
PRDHYDS	Hydro Specific Proj 107303 / Removal Use Ferc CC
PRDNUCS	Nuclear Specific Proj 107301 / Removal Use Ferc CC
PRDOTHS	Peaker Specific Proj 107302 / Removal Use Ferc CC
PRDSTMS	Steam Fossil Specific Proj 107300 / Removal Use Fe
PSI	Spc Preliminary Survey & Investigation 183000
REASDEV	Spc Research & Development 188000
SLOHS	Spc Street Lighting Overhead 107316 / 108527
SLUGS	Spc Street Lighting Underground 107317 / 108527
STMLNDS	Spc Fossil Site & R of W 107337 / 108522
STRUCTS	Spc Buildings & Related Projects 107322 / 108529
SUBBLLS	Spc Billings to Subsidiaries 186415
TEMPS	Spc Temporary Facilities 185000
TL138S	Spc Transmission Lines 138KV 107308 / 108526
TL230S	Spc Transmission Lines 230KV 107347 / 108526
TL23KVS	Spc Transmission Lines 23KV 107305 / 108526
TL345S	Spc Transmission Lines 345KV 107309 / 108526
TL34KVS	Spc Transmission Lines 34KV 107306 / 108526
TL500S	Spc Transmission Lines 500KV 107348 / 108526
TL69KVS	Spc Transmission Lines 69KV 107307 / 108526
TLLANDS	Spc Trans Lines Site & R of W 107341 / 108526
TLO115S	Spc Project TX OH Lines 115KV 107000 / 108000
TLO11S	Spc Project TX OH Lines 11.8KV 107000 / 108000
TLO13S	Spc Project TX OH Lines 13.8KV 107000 / 108000
TLO25S	Spc Project TX OH Lines 25KV 107000 / 108000
TLO36S	Spc Project TX OH Lines 36KV 107000 / 108000
TLO46S	Spc Project TX OH Lines 46KV 107000 / 108000
TLO765S	Spc Project TX OH Lines 765KV 107000 / 108000
TLOTHS	Spc Transmission Lines Other 107311 / 108526
TLU115S	Spc Project TX URD Lines 115KV 107000 / 108000
TLU11S	Spc Project TX URD Lines 11.8KV 107000 / 108000
TLU138S	Spc Project TX URD Lines 138KV 107000 / 108000
TLU13S	Spc Project TX URD Lines 13.8KV 107000 / 108000
TLU230S	Spc Project TX URD Lines 230KV 107000 / 108000
TLU23S	Spc Project TX URD Lines 23KV 107000 / 108000
TLU25S	Spc Project TX URD Lines 25KV 107000 / 108000
TLU345S	Spc Project TX URD Lines 345KV 107000 / 108000
TLU34S	Spc Project TX URD Lines 34KV 107000 / 108000
TLU36S	Spc Project TX URD Lines 36KV 107000 / 108000
TLU46S	Spc Project TX URD Lines 46KV 107000 / 108000
TLU500S	Spc Project TX URD Lines 500KV 107000 / 108000
TLU69S	Spc Project TX URD Lines 69KV 107000 / 108000
TLU765S	Spc Project TX URD Lines 765KV 107000 / 108000
TLUGS	Spc Trans Lines UG <69KV 107310 / 108526
TRANSFS	Spc Project Transformers Only 107318 / 108527
TRANUGS	Spc Trans Lines UG <69KV 107310 / 108526
TRLANDS	Spc Trans Sub Site & R of W 107340 / 108526
TRNSUBS	Spc Transmission Substations 107304 / 108526

Available Grid Filters

WBS Element Filters

- **Interest Profile = Other**

DXOMMIC	Dist O&M - Misc Exps 588 / 598
DXOMMTR	Dist O&M - Meter Exps 586 / 597
DXOMOH	Dist O&M - Overhead Lines 583 / 593
DXOMSTL	Dist O&M - Street Lighting 585 / 596
DXOMSUB	Dist O&M - Substation 582 / 592
DXOMURD	Dist O&M - Underground Lines 584 / 594
DXOMXFM	Dist O&M - Overhead Transformers 583 / 595
INDA&G	Undist Const Overheads - Admin & General 107334
INDENG	Undist Const Overheads - Engineering 107335
INDSH	Undist Const Overheads - Stores Handling 107330
INDSUPV	Undist Const Overheads - Supervision 107332
INDTRAN	Undist Const Overheads - Transportation 107331
PRDHYDO	Hydro O&M Proj SETTLE TO COST CENTERS ONLY
PRDNUCO	Nuclear O&M Proj SETTLE TO COST CENTERS ONLY
PRDOTHO	Peaker O&M Proj SETTLE TO COST CENTERS ONLY
PRDSTMO	Steam Fossil O&M Proj SETTLE TO COST CENTERS ONLY
PRDSUBS	All Gen Trans Subst 107304 / Removal Use Ferc CC
TOTPRJ	Total Project Place Holder Only
TXOMMIS	Trans O&M - Misc Exps 566 / 573
TXOMSUB	Trans O&M - Substation 562 / 570
TXOMURD	Trans O&M - Underground Lines 564 / 572

Roles and Responsibilities

Roles and Responsibilities

HRIS – (B2) 1

- Create HR information file for interface

IBP – (B2) 2

- Create scenario/cases
- Maintenance of hierarchy trees
- Monitoring/validation of UIPlanner interfaces (on-demand)
  - Master data
  - Companies
  - Power Plant

Business Services / Planning & Anaysis / Operations – (B2) 3

- Input controlled and assigned labor (overtime), OTL and Capital dollars into UIP
- Labor pool validation

General Acct (PA) – (B2) 4

- Update of costing sheets (OH)
- Create cost center assessments, variants and cycles

IBP – (B2) 5

- Application of overheads
- Execution of settlements (Plan vs. Actual)
- Update variants in UIP (provided by GA-PA)
- Execution of assessments
- Run data validation reports
- Run financial reports
- Execution of FERC process
- Run FERC derivation validation reports

FEU Long Term Planning – (Model) 6

- Run Rider/Deferral reports
- Validate results and review with Acctg.

Property Accounting – (Model) 7

- Powerplant interface validation
- Existing plant depreciation calculation validation
- Existing plant AFUDC calculation validation
- Plant addition depreciation/AFUDC calculation validation

Treasury – Debt/Interest (Model) 8

- Update debt transactions, debt amortizations and reacquired debt projections

Tax Planning (Model) 9

- Validation of apportionment factor interface
- Unitary tax calculation validation
- Schedule M item confirmation
- Existing and additions tax depreciation and deferred tax calculation validation
- Tax sharing agreements

Roles and Responsibilities – Labor Planning

- Labor pool preparation – gross payroll, unproductive/productive hours and activity pricing will be developed within UIPlanner
- Finalize labor pool – shift differentials, headcount adjustments
- Labor pool validation – balance labor among capital and cost center, lock budget node

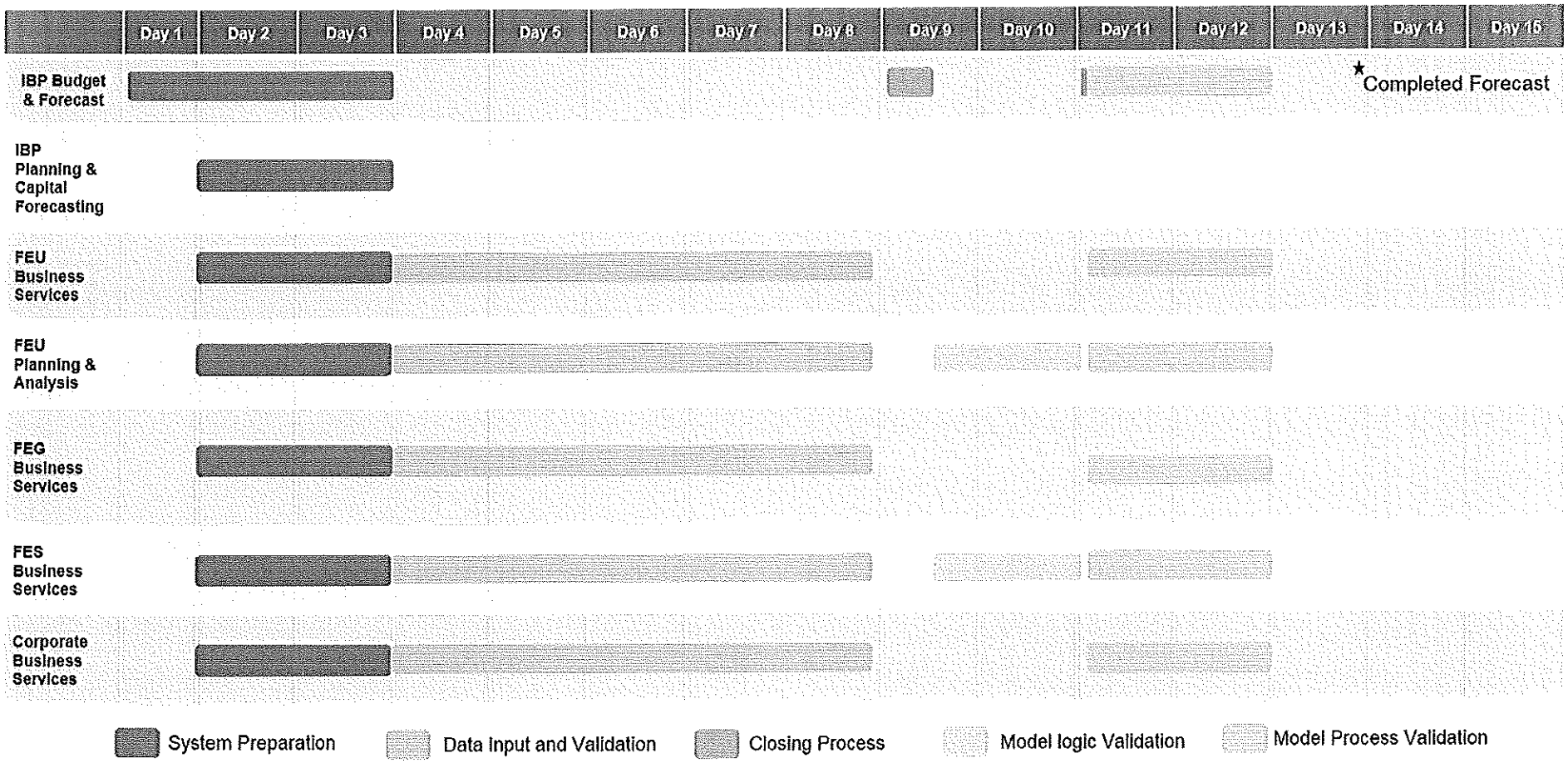
	Labor Pool Prep	Finalize Labor Pool	Develop & Enter Labor for Cost Center	Develop Labor for to Blankets	Enter Labor for Blankets	Develop Labor for Specifics & Programs	Enter Labor for Specifics & Programs	Final Labor Pool Validation
UI Planner	FES, FEG FEU/ FET Corp							
Business Services		FES, FEG FEU/ FET Corp	FES, FEG FEU / FET Corp	FEU/FET	FEU/FET	FEG, Corp, FES, FEU/FET	FEG, Corp	FES, FEG FEU/FET Corp
Operations							FES, FEU/FET	

Roles and Responsibilities – OTL Planning

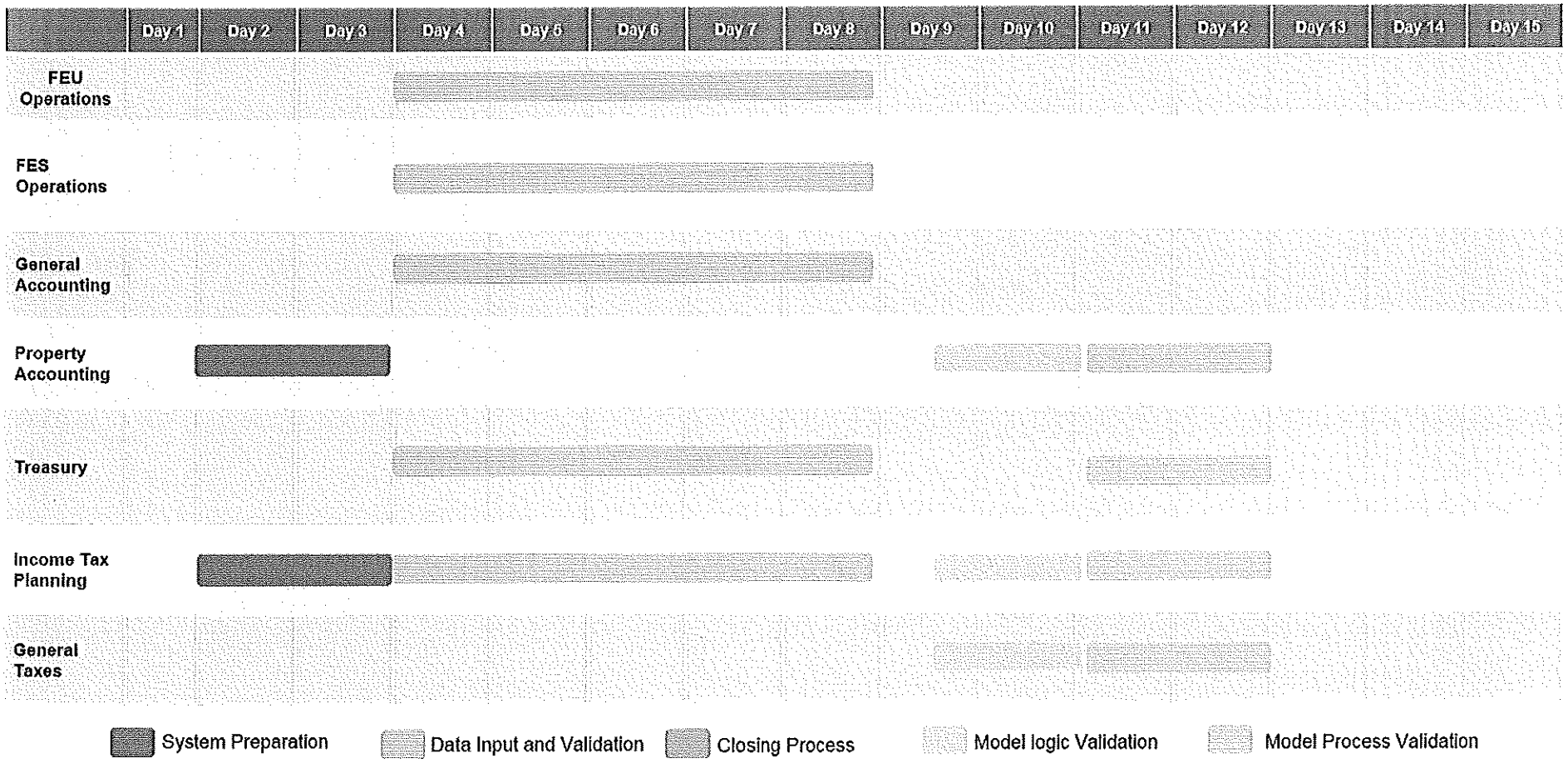
- Reference – users will review previous forecast and actual data within UIPlanner to aid in the development of current forecast
- Development and Validation – users will utilize budget templates or UIPlanner directly for creating and executing reports to ensure data is correctly entered

	Reference Actuals / Prior Forecasts	Develop and Enter Cost Center OTL	Develop Blankets & Outage OTL	Enter Blankets & Outage OTL	Develop Specific & Program OTL	Enter Specific & Program OTL	Final OTL Validation
UI Planner	FES, FEG FEU / FET Corp						
Business Services		FES, FEG, FEU/FET, Corp	FES, FEG FEU / FET	FES, FEG, FEU/FET	FES, FEG, FEU/FET, Corp	FES, FEG, FEU/FET, Corp	FES, FEG FEU / FET Corp
Operations						FEU / FET	

UIP Work Flow Schedule



UIP Work Flow Schedule

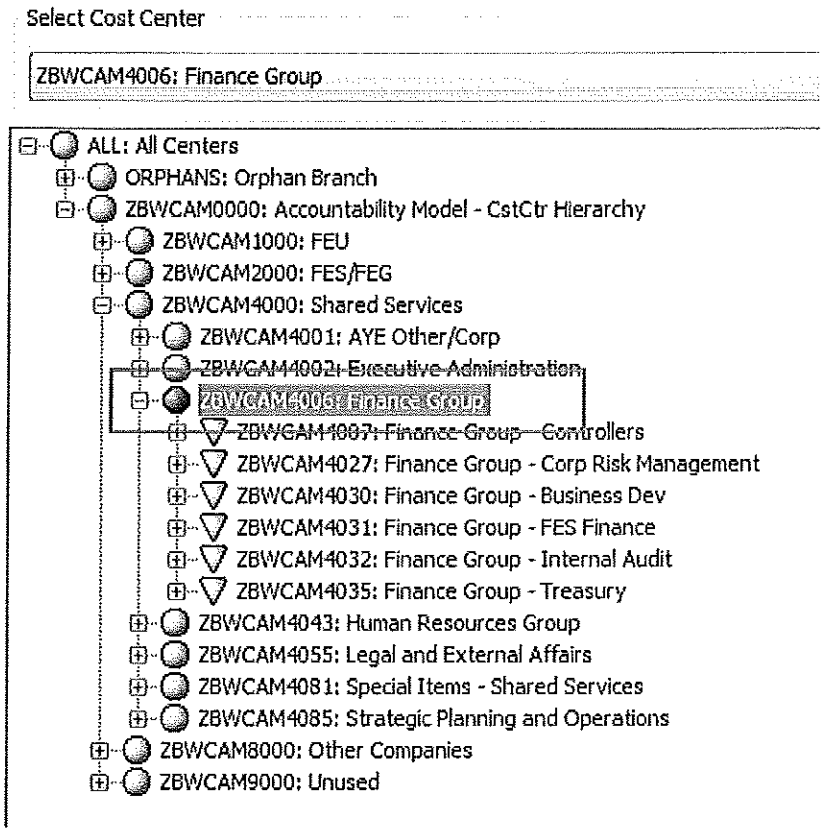


Cost Center Locking

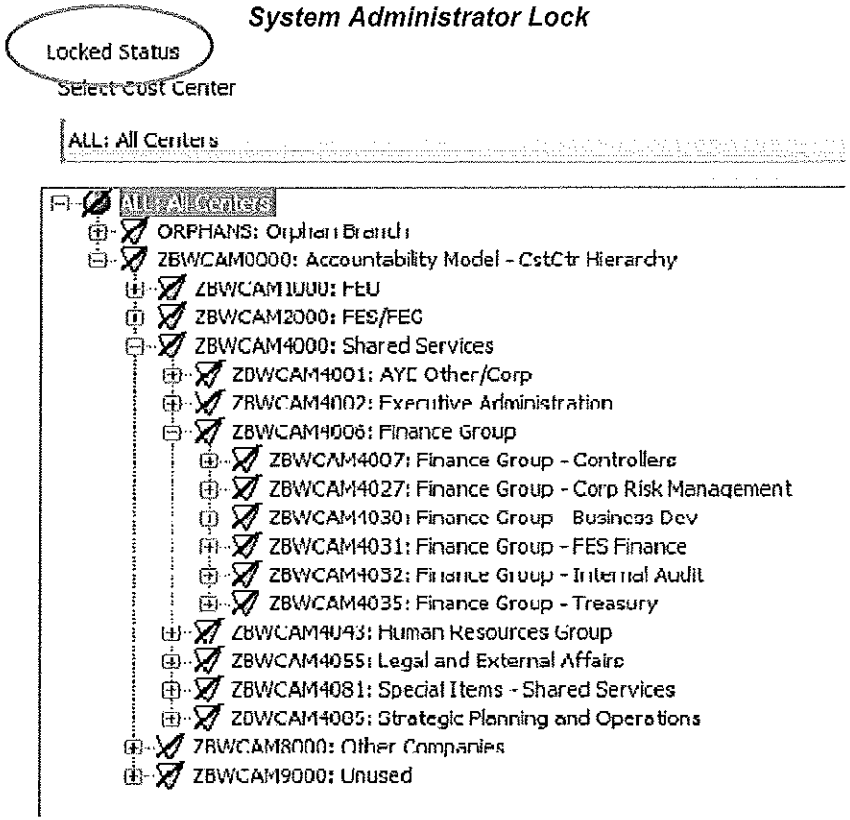
Cost Center Locking Overview

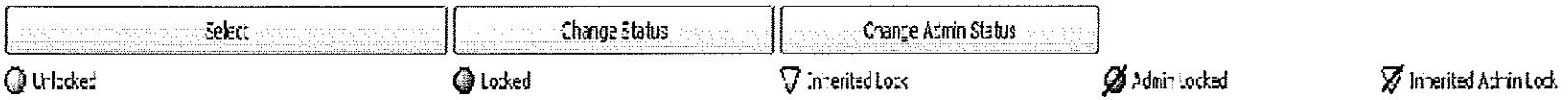
- Budget Administrators can lock their cost centers prior to system processing
- Cost Center locking will serve as part of the budget, forecast and plan approval process
- System Administrator can view user status and perform a global cost center lock
- Cost Center locking also prevents users from entering data to the grid

Budget Owner/Budget Administrator Lock



System Administrator Lock

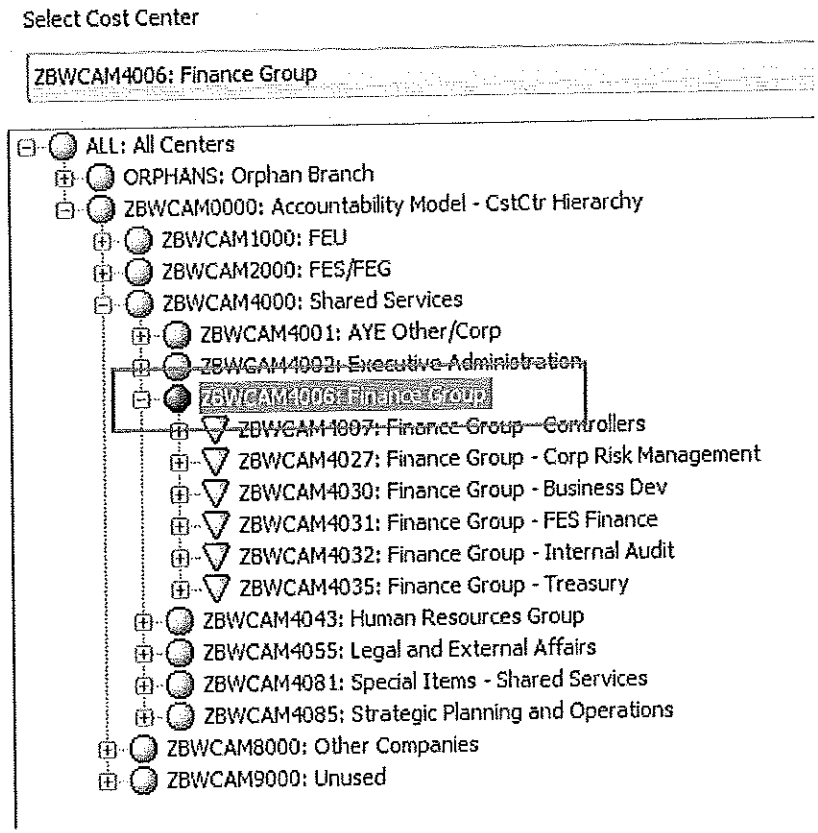


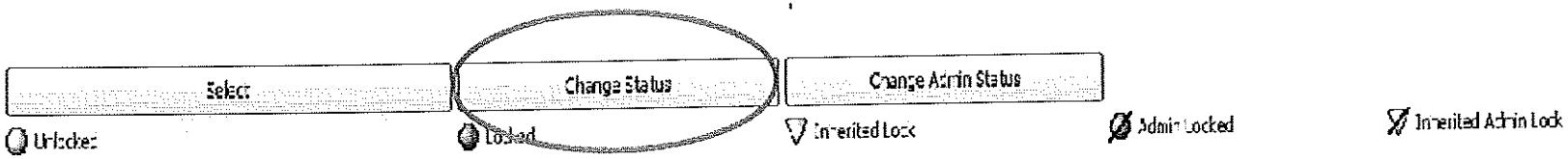


Cost Center Locking

1. Highlight the cost center or cost center node you want to lock
2. Click **Change Status** button on bottom of screen
3. The selected group will lock at the node level (red circle) and perform an inherit lock for all cost centers under that node. Click **Change Status** again to unlock
4. Cost center locking can also be done at the individual cost center level
5. WHEN TRAINING, PLEASE DO NOT LEAVE ANY COST CENTERS LOCKED

Budget Coordinator Lock





Cost Center Locking

- The System Administrator will have the ability to lock the entire system (scenario). This action would typically be done once the budget or forecast is ready to close and process

- Highlight the cost center or cost center node you want to lock

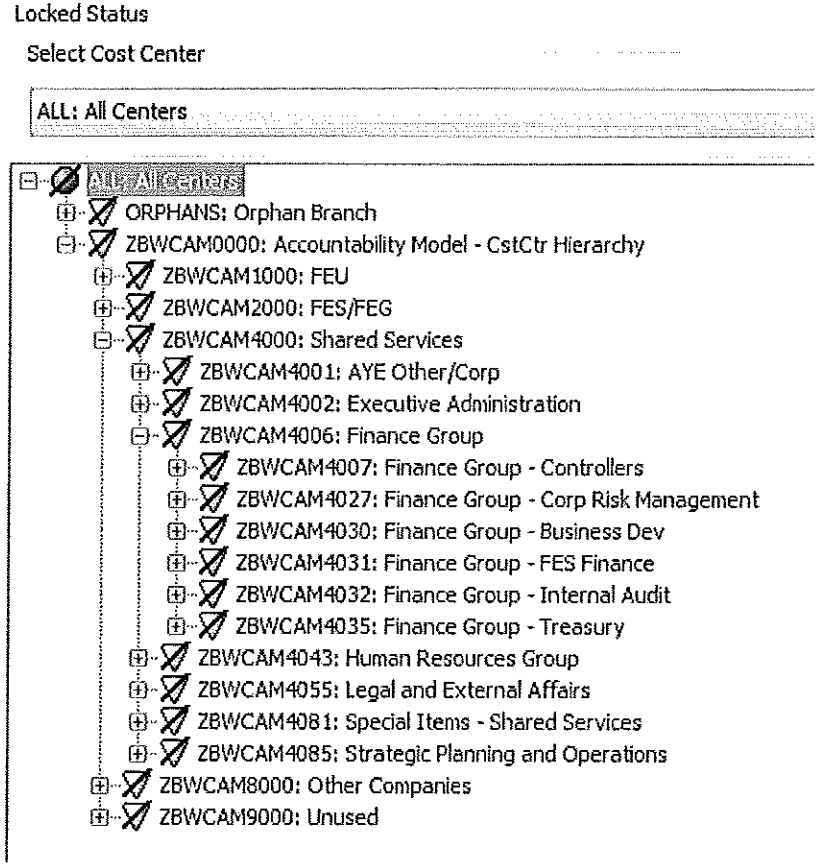
- Click **Change Admin Status** button on bottom of screen. A strike will be appear across the circle and triangles. Click **Change Admin Status** again to unlock

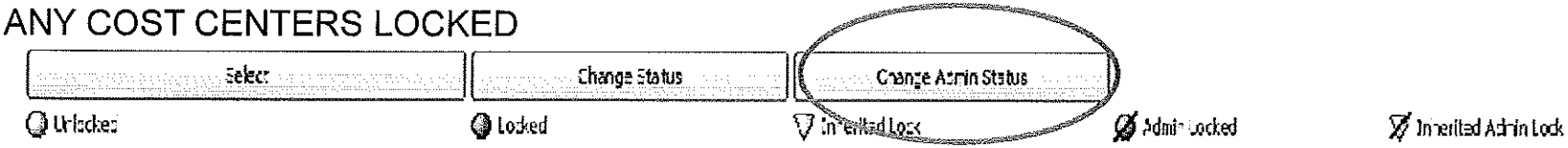
- The selected group will lock at the node level (red circle) and perform an inherit lock for all cost centers under that node. Cost center admin locking can also be done at the individual cost center level

- Your security level may not allow you to do a system lock

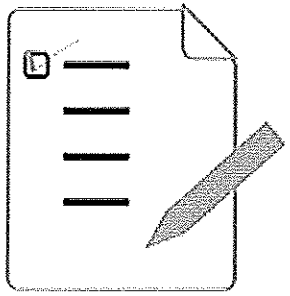
- WHEN TRAINING, PLEASE DO NOT LEAVE ANY COST CENTERS LOCKED

System Administrator Lock





Exercise #4 – Browse Cost Center and Center Locking

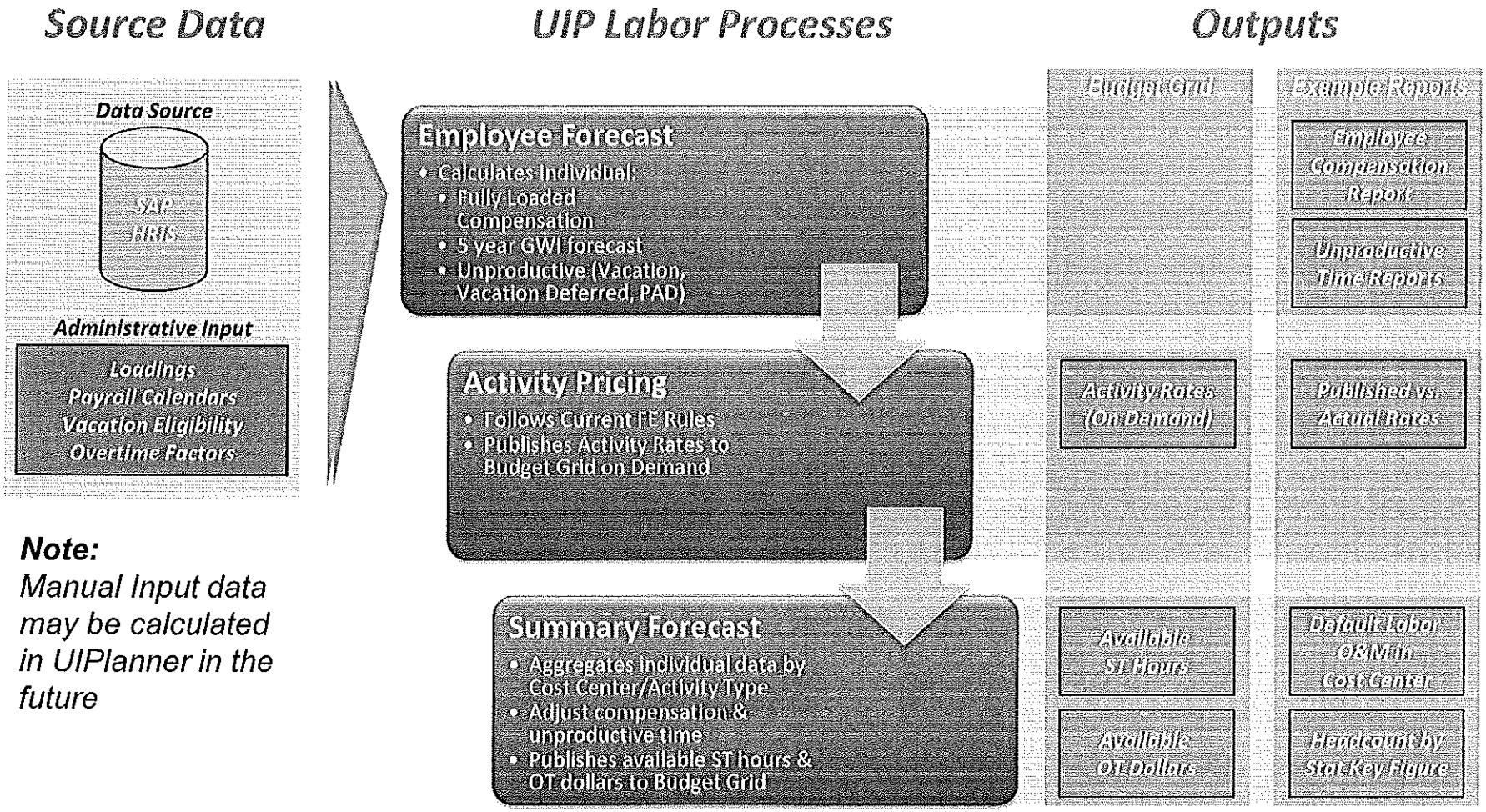


Use the previous slides to perform the following tasks

- Review the new cost center hierarchy for your Business Unit/Department
- Expand and collapse the hierarchy
- Search a cost center
- Perform a cost center lock for an individual cost center or group
  - Remember to unlock all cost centers before exiting the screen

Employee Labor

UIPlanner Labor Schematic



Note:
Manual Input data may be calculated in UIPlanner in the future

The new Labor process ensures that activity rates will be available prior to the budget process while enhancing data security and transparency

Employee Labor Overview - Benefits

Edit Forecasts at Multiple Levels

- Interact with labor data and edit forecasts at the individual employee or cost center level

Activity Prices Prior to Budgeting

- UIPlanner will calculate activity prices prior to the start of the annual budget process. In addition, SAP HR data will be interfaced to UIPlanner monthly

Calendars & Loadings Auto Calculated

- Additional employee information such as vacation eligibility, available payroll hours, etc… will be summarized to help facilitate building of the labor budget

Enhanced Data Security

- Access to the labor screens will be secured based on user role and business unit/department

Automated 5 Year Labor Forecast

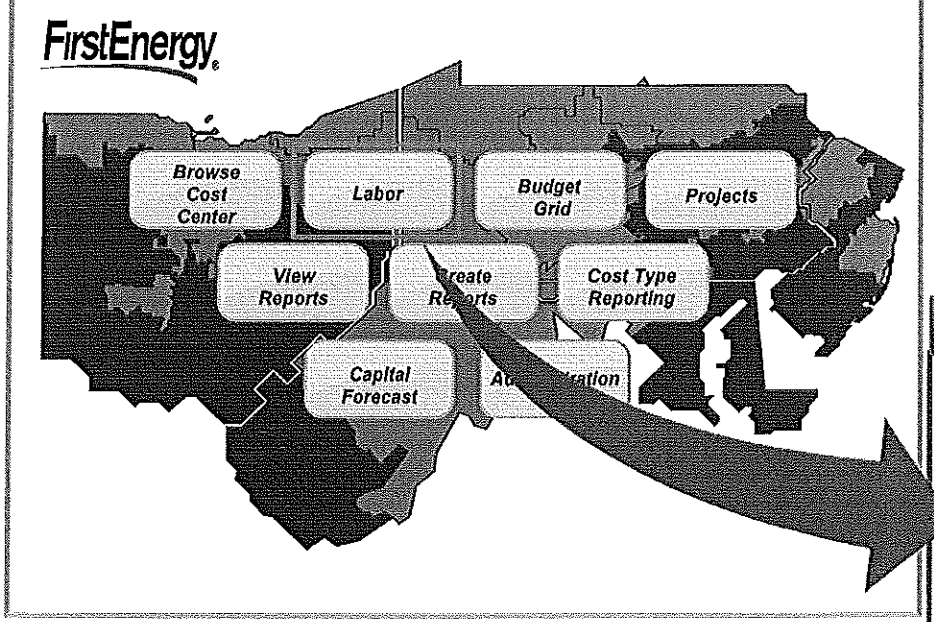
- The correct business rules are applied producing calculated results across the planning horizon for each employee

Labor Attributes Imported from SAP

- *Employee Number*
- *Employee Name*
- *Company*
- *Organization*
- *Personnel Area*
- *Personnel Sub Area*
- *Position*
- *Job*
- *Job Group*
- *Region*
- *Employee Group*
- *Employee Subgroup*
- *Cost Center*
- *Activity Type*
- *Pay Scale Type*
- *Pay Scale Area*
- *Annual Salary*
- *Unit Pay*
- *Vacation Eligibility Date*
- *Latest Hire Date*
- *Vacation Used to Date*
- *PAD Used to Date*
- *Vacation Rolled Over from Previous Year*

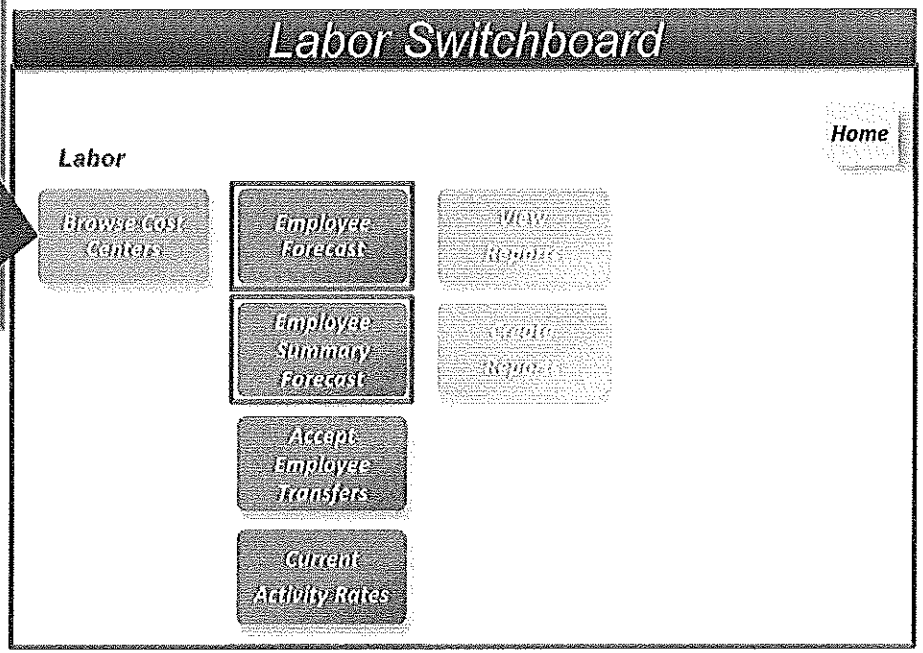
Employee Labor Overview - Navigation

Home Switchboard



1. Click the "Labor" button to open the Labor Switchboard

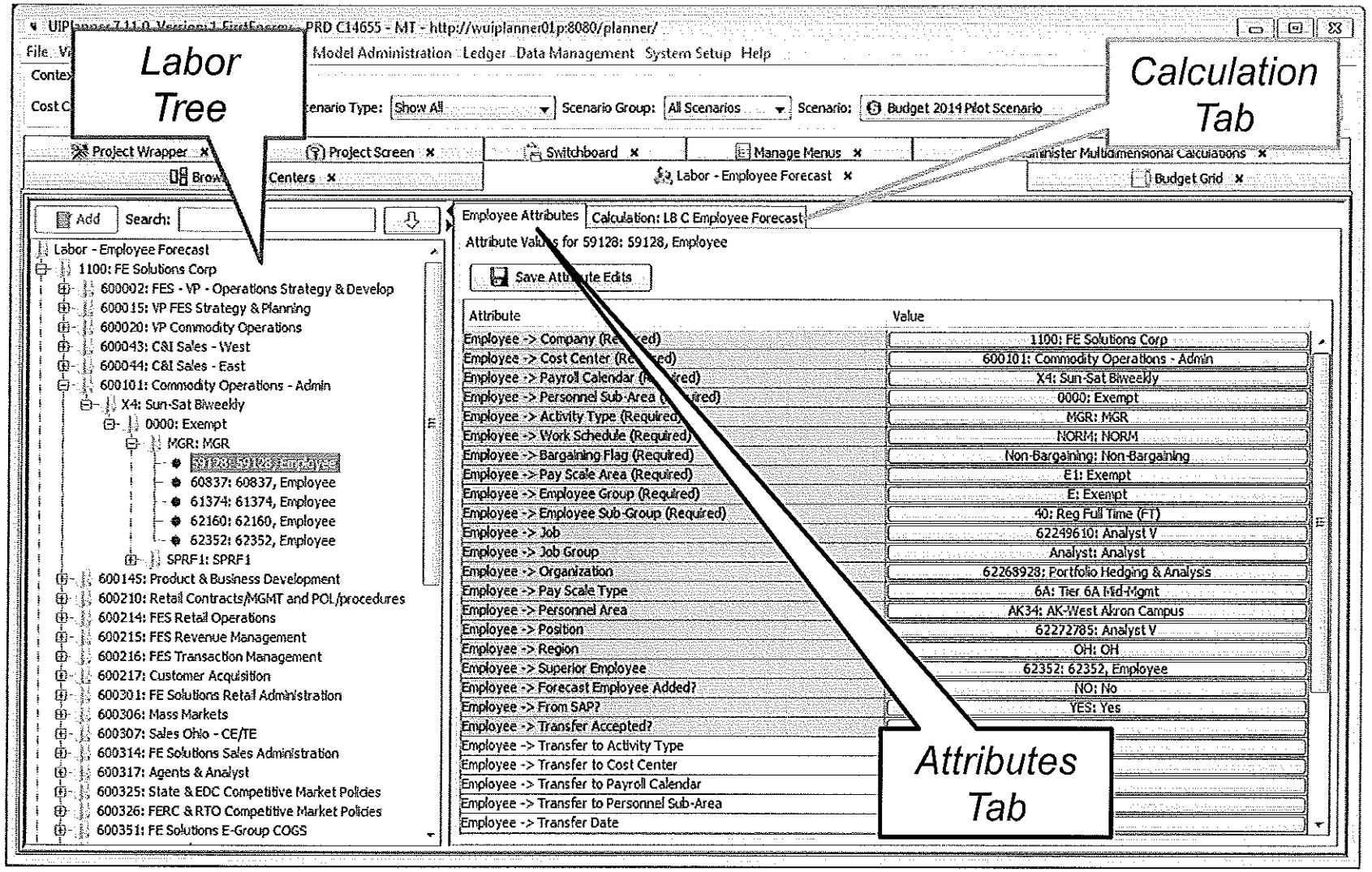
Labor Switchboard



2. Select "Browse Cost Centers" to select the center you wish to view/edit
3. Then click "Employee Forecast"
4. Then click "Summary Forecast"

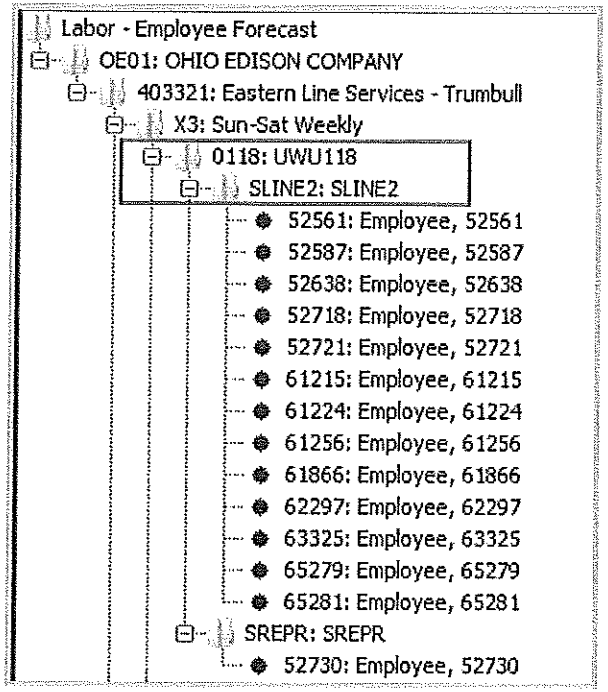
Employee Labor Overview - Wrappers

The Two Labor Wrappers have Three Main Sections

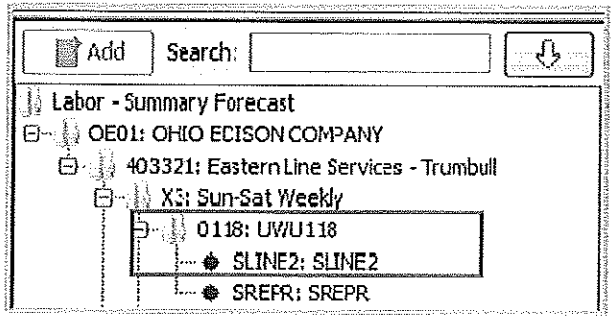


Employee Labor Overview - Trees

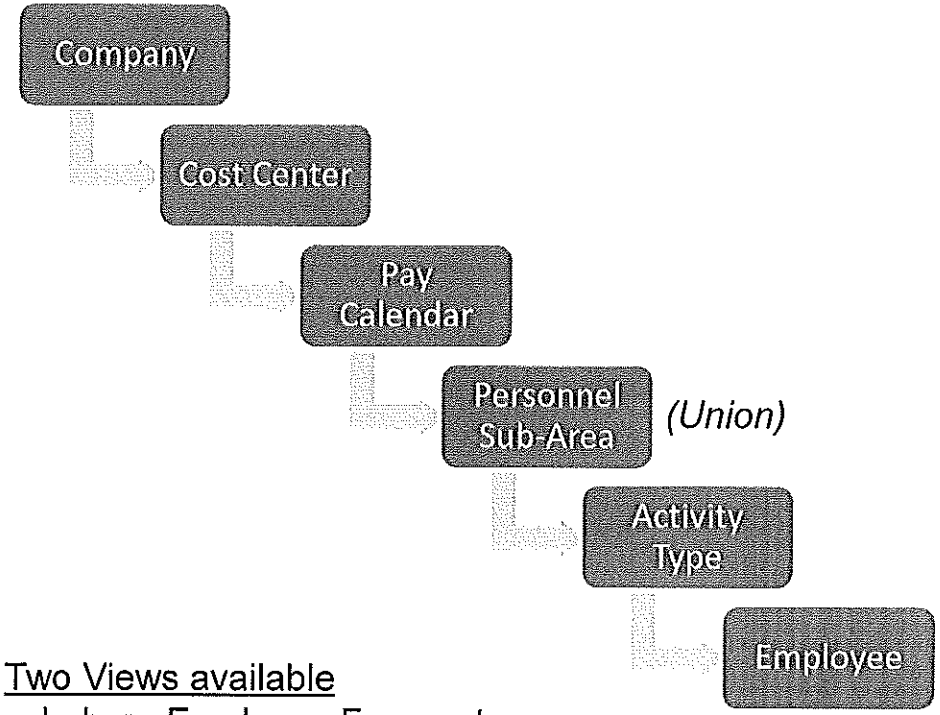
Employee Forecast



Summary Forecast



Labor data will be organized and presented in a tree format by:



Two Views available

- Labor - Employee Forecast
- Labor - Summary forecast

To View Data

- **Employee Forecast:** Open tree to employee level and click on an employee
- **Summary Forecast:** Open tree to activity type level and click on an activity type

Employee Labor Overview – Attributes Tab

The Employee Attributes tab contains a list of each employee's attributes including imported SAP and those that can be set by users

Three Types of Inputs

Attributes: *Opens a dropdown list of attributes*

Dates: *UIPlanner date fields open in a pop-up calendar in MM/YYYY format*

Numbers: *Numbers in UIPlanner can be entered freeform. Note SAP dates in UIPlanner are entered as numbers in YYYYMMDD format*

Employee Attributes | Calculation: L0 C Employee Forecast

Attribute Values for 52561: Employee, 52561

Save Attribute Edits

Attribute	Value
Employee -> Activity Type (Required)	SUINF2: SUINF2
Employee -> Bargaining Flag (Required)	Bargaining: Bargaining
Employee -> Company (Required)	OE01: OHIO EDISON COMPANY
Employee -> Cost Center (Required)	103321: Eastern Line Services - Trumbull
Employee -> Employee Group (Required)	0: Barg/Physical
Employee -> Employee Sub-Group (Required)	40: Reg Full Time (FT)
Employee -> Forecast Employee Added?	NO: No
Employee -> From SAP?	YES: Yes
Employee -> Job	60001666: Line Troubleshooter-U1
Employee -> Job Group	Lineworkers: Lineworker
Employee -> Organization	60000195: RegOH-E: Operations-Warren (OE)
Employee -> Pay Scale Area (Required)	U1: UWUA Local 118/126
Employee -> Pay Scale Type	01: Bargaining
Employee -> Payroll Calendar (Required)	X1: Sun-Sat Weekly
Employee -> Personnel Area	KI01: Kinsman Line Shop
Employee -> Personnel Sub-Area (Required)	0118: UWU118
Employee -> Position	61000182: Line Troubleshooter
Employee -> Region	OH: OH
Employee -> Superior Employee	52573: Employee, 52573
Employee -> Transfer Accepted?	
Employee -> Transfer to Activity Type	
Employee -> Transfer to Cost Center	
Employee -> Transfer to Payroll Calendar	
Employee -> Transfer to Personnel Sub-Area	
Employee -> Work Schedule (Required)	FLEX12HR: Flex 12 hrs
Employee -> Annual Salary (Required)	20800
Employee -> Exit Date	
Employee -> Latest Hire Date (YYYYMMDD) (Required)	19681028
Employee -> PAD Used to Date	48

Select Employee -> Exit Date

Selected Month: | Time Forward | Time Back | Clear

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2013	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2014	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2015	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2016	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2017	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2018	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2019	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2020	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...
2021	1/2...	2/2...	3/2...	4/2...	5/2...	6/2...	7/2...	8/2...	9/2...	10/...	11/...	12/...

OK | Cancel

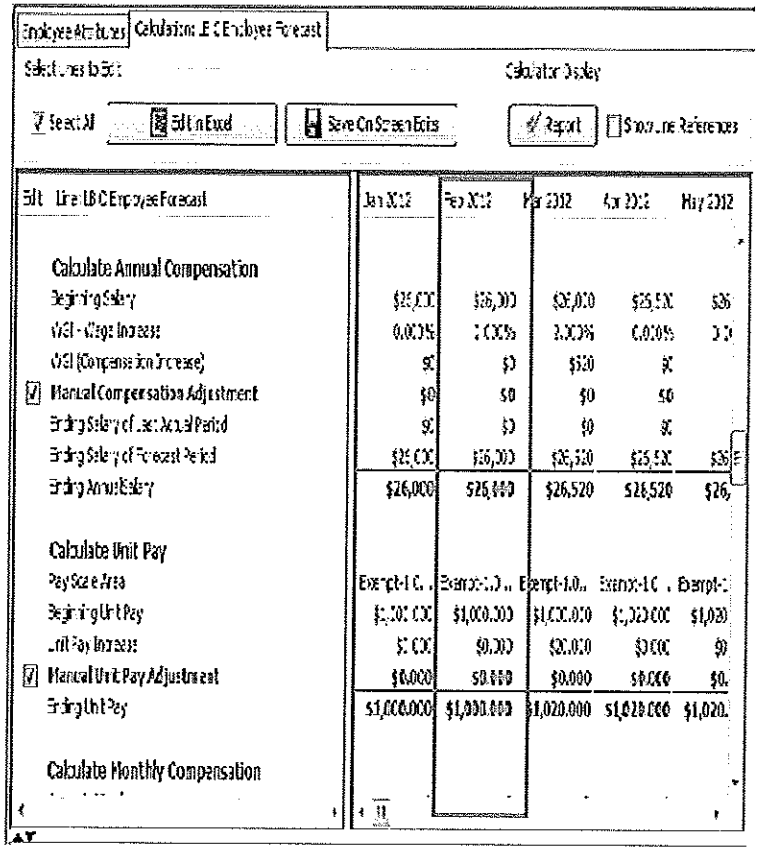
- White attributes **are** editable
- Grey attributes **are not** editable

Employee Labor Overview – Calculations (Overview)

Employee Forecast Calculations

1. Employee Headcount & FTE
2. PAD
3. Vacation
4. Vacation Deferred
5. Unit Pay
   - a. *Bi-Weekly (Exempt)*
   - b. *Hourly (Non-Exempt)*
6. Compensation
   - a. *Monthly Compensation*
   - b. *Annual Compensation*
7. Loadings (Admin Maintained)
   - a. *Incentive Compensation Plan*
   - b. *Payroll Tax*
   - c. *Benefits Loading*
8. Fully Loaded Compensation
9. Productive Time (Activity Pricing) — Hours Available (for Budget Grid)
10. Overtime Factors

- Select the Calculation Tab
- Listed are the key data fields and activity price calculation
- Only rows highlighted in yellow can be edited



Employee Labor Calculations – Headcount & FTE

1 Calculate Headcount & FTE Level

Edit	Line: LB C Employee Forecast	Jan 2014	Feb 2014	Mar 2014	Apr 2014
	Calculate Employee Headcount				
	Begin Employee Count		1	1	1
	Employee Added				
	Employee Exited				-1
	Transfer Employee Out				
	Transfer Employee In				
	End Employee Count		1	1	
	Calculate FTE				
	Begin FTE Count		1.0	1.0	1.0
	Initial FTE Count				
	FTE Added				
	FTE Exited				-1.0
	Transfer FTE Out				
	Transfer FTE In				
☑	**FTE Adjustment**				
	Final FTE Count		1.0	1.0	

- "1" displays for the beginning headcount in the employee labor forecast regardless of employee status
- "1" displays if the employee is considered full time
- "0.5" defaults if the employee status is part-time
- Only part-time employee FTE levels are editable

Employee Labor Calculations – Unproductive Time

2. Calculate PAD
3. Calculate Vacation
4. Calculate Vacation Deferred

Edit	Line: LB C Employee Forecast	Jan 2013	Feb 2013	Mar 2013
	Calculate PAD			
	Begin Available PAD Count		32	32
	Annual PAD Allocation	32		
☑	**Forecasted PAD Use**			
	PAD Used to Date			
	End Available PAD Count	**32**	**32**	**32**
	Vacation Allocation Data			
	Vacation Eligibility Date (YYYYMM)	Oct 1968	Oct 1968	Oct 1968
	Vacation Eligibility Year (YYYY)	1969	1969	1969
	Months of Credit	531	532	533
	Years of Credit for Vacation	44	44	44
	Vacation Allocation Calculation			
	Beginning Vacation Available		160	160
	Vacation Allocation	200		
☑	**Forecasted Vacation Use**	**40**		
	Vacation Used to Date (Last Actual Period)			
	Ending Vacation Available	**160**	**160**	**160**
	Vacation Deferred Calculation			
	Beginning Vacation Deferred		80	80
	Vacation Deferred Allocated	80		
☑	**Forecasted Vacation Deferred Use**			
	Vacation Deferred from Previous Year (Used to...			
	Ending Vacation Deferred Available	**80**	**80**	**80**

- PAD eligibility displays for each employee
- Forecast PAD for employee by entering the number of hours forecasted each month

- Vacation hours available
- Vacation calculation based on employee service
- Forecast Vacation for employee by entering the number of hours forecasted each month
- Hours reduced for following month

- Vacation Deferred available
- Forecast Vacation Deferred for employee by entering the number of hours forecasted each month

Employee Labor Calculations - Compensation

5 Unit Pay (w/ GWI Increases)

6 Calculate Compensation

Edit	Line: LB C Employee Forecast	Oct 2014	Nov 2014	Dec 2014
	Calculate Unit Pay			
	Pay Scale Area	Exempt-1.0...	Exempt-1.0...	Exempt-1.0...
	Beginning Unit Pay	$2,118.469	$2,118.469	$2,118.469
	GWI - Wage Increase (%)			
	Unit Pay Increase			
☑	**Manual Unit Pay Adjustment**			
	Ending Unit Pay	**$2,118.469**	**$2,118.469**	**$2,118.469**
6a	**Calculate Monthly Compensation**			
	Weeks in Month	4	4	4
	Hours Per Week	40	40	40
	Total Hours in Month	160	160	160
	Monthly Compensation (Exempt)	$4,237	$4,237	$4,237
	Monthly Compensation (Hourly)			
	Annual Direct Salary			$54,872
	Total ST Hours in Year			2,080

Edit	Line: LB C Employee Forecast	Oct 2014	Nov 2014	Dec 2014
6b	**Calculate Annual Compensation**			
	Annual Employee Hours	2,080	2,080	2,080
	Current Month ST Hours	160	160	160
	Beginning Annual Salary	$55,080	$55,080	$55,080
	GWI - Wage Increase (%)			
	GWI - Compensation Increase			
	Ending Annual Salary	$55,080	$55,080	$55,080
	Bonus Compensation Allocation			
☑	**Bonus Compensation**			

- Display pay scale are and unit pay
- Enter pay adjustments if applicable (promotion, non ICP bonus, etc...)
- Based on employee, number of hours available displays
- Total monthly compensation calculated
- Annual compensation calculated
- Add additional bonus pay

Employee Labor Calculations - Loadings

7 Compensation Loadings

Edit	Line: LB C Employee Forecast	Oct 2014	Nov 2014	Dec 2014
	Compensation Loadings			
7a	**Incentive Compensation Loading**			
	Monthly Compensation	$4,237	$4,237	$4,237
	* Incentive Compensation Loading (%)	10.00%	10.00%	10.00%
	Incentive Compensation Allocated	$424	$424	$424
7b	**Payroll Tax Loading**			
	Monthly Compensation	$4,237	$4,237	$4,237
	* Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	Payroll Tax for Base Compensation	$319	$319	$319
	Incentive Compensation Allocated	$424	$424	$424
	* Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	Payroll Tax for ICP	$32	$32	$32
	Payroll Tax for Base Compensation	$319	$319	$319
	Payroll Tax for ICP	$32	$32	$32
	Payroll Tax Allocated	$351	$351	$351
7c	**Benefits Loading**			
	Monthly Compensation	$4,237	$4,237	$4,237
	* Benefits Loading (%)	22.14%	22.14%	22.14%
	Benefits Allocated	$938	$938	$938

- Compensation loadings calculated
- Incentive Compensation, Payroll Tax, and Benefits percentages stored in multidimensional dataset

Employee Labor Calculations – Total Loaded Compensation

8 Fully Loaded Compensation

Edit	Line: LB C Employee Forecast	Oct 2014	Nov 2014	Dec 2014
	Total Compensation Loadings			
	Incentive Compensation Loading (%)	10.00%	10.00%	10.00%
	+ Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	+ Payroll Tax Loading (%) * ICP (%)	0.75%	0.75%	0.75%
	+ Benefits Loading (%)	22.14%	22.14%	22.14%
	Total Loading Percent	40.43%	40.43%	40.43%
8a	**Loaded Monthly Compensation**			
	Incentive Compensation Allocated	$326	$326	$326
	+ Payroll Tax Allocated	$271	$271	$271
	+ Benefits Allocated	$723	$723	$723
	Total Loading Dollars	$1,320	$1,320	$1,320
	+ Monthly Compensation	$3,264	$3,264	$3,264
	Loaded Monthly Compensation	**$4,584**	**$4,584**	**$4,584**
8b	Loaded Annual Salary for Activity Pricing			**$59,364**
	Loaded Bonus Compensation Allocation			
	Bonus Compensation			
	* Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	Total Loaded Bonus Compensation			

- Compensation loadings listed totaling labor additives
- Compensation dollars totaling for labor additives
- Loadings applied to Bonus Compensation dollars

Employee Labor Calculations – Available Hours

9 Calculate Available Hours

Edit	Line: LB C Employee Forecast	Oct 2014	Nov 2014	Dec 2014
	Calculate Productive Time for Activity P...			
	Straight-time Hours in Months	160	160	160
	Meeting Hours	3.33	3.33	3.33
	Unproductive Time (Additional)			
	Total Hours in Year			2,080
	Meeting Hours in Year			40
	Unproductive Time (Additional) in Year			
	Vacation Allocation			85
	PAD Allocation + Holiday			96
	Productive Time in Year			**1,859**
	Hours Available for Budgeting			
	Total Hours in Month	160	160	160
	Vacation Budgeted/Used			
	Vacation Deferred Budgeted/Used			
	PAD Hours Budgeted/Used			
	Holiday Hours			16
☑	**Miscellaneous Unproductive Time in Budget**			
	Time Available for Budgeting	160	160	144

- Productive time calculated for activity pricing
- Hours available for budgeting
- Include additional unproductive time

Under development - Descriptions will display

Employee Labor Calculations – Overtime Inputs

10 Overtime Loadings

Edit	Line: LB C Employee Forecast	Jan 2013	Feb 2013	Mar 2013
	Monthly Base Salary	$3,200.00	$3,200.00	$4,000.00
	Escalation Factor	1.67780	1.67780	1.67780
	Monthly Overtime Base Salary	$5,368.96	$5,368.96	$6,711.20
	Incentive Compensation Loading	5.00%	5.00%	5.00%
	Incentive Compensation for Overtime	$268.45	$268.45	$335.56
	Monthly Overtime Base Salary	$5,368.96	$5,368.96	$6,711.20
	+ Incentive Compenstation for Overtime	$268.45	$268.45	$335.56
	Taxable Overtime Compensation	$5,637.41	$5,637.41	$7,046.76
	* Tax Loading	7.54%	7.54%	7.54%
	Taxes On Base Salary for Overtime	$425.06	$425.06	$531.33
	Monthly Loaded Salary for Overtime	$6,062.47	$6,062.47	$7,578.09
	Monthly Hours for Overtime	160	160	200

- Escalation factors are used to inflate base salaries to approximate hourly overtime rates

Employee Labor - How to Update Data

Two options to update Employee Labor

Edit on Screen



- *Inputs can be made directly in the screen.*
- *Select save on screen edits*

Edit In Excel



	B	C	D	E
1	Line Item to Edit	Jan 2013	Feb 2013	Mar 2013
2				
3	VR:[Forecasted PAD Use]			
4	WY:[Forecasted Vacation Use]			
5	YI:[Forecasted Vacation Deferred Use]			
6	ZC:[Manual Unit Pay Adjustment]			
7	ABM:[Bonus Compensation]			
8	AEL:[Miscellaneous Unproductive Time in Budget]			

- You can edit the rows highlighted in yellow or Select the **Edit in Excel** to update
  - When editing in Excel simply close out to save
  - Column headings will need to remain in tact in order to properly save

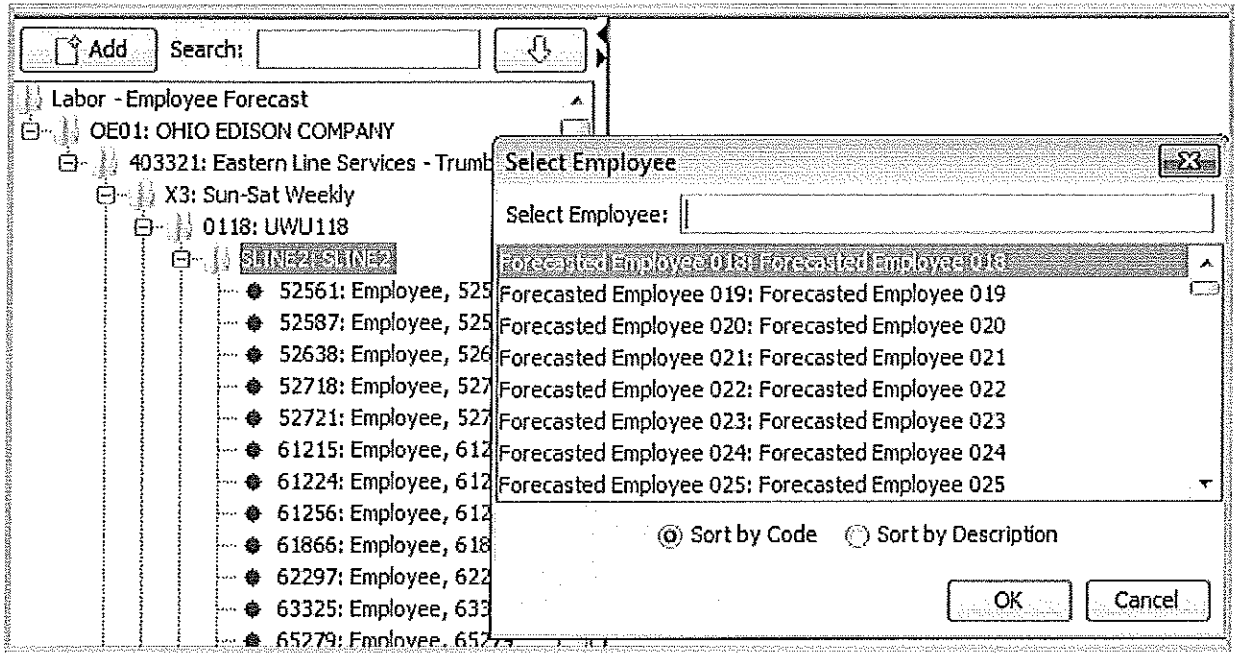
Employee Labor – Forecasting Headcount Changes

Employee Labor – Add a Forecast Employee

Forecast Employees are employee entities which can be added to the labor forecast to forecast new employees in a department. Forecast Employees should be used when either: ***1.) the position has been filled and the employee has not started yet, or 2.) the Cost Center/Activity Type does not exist within FE.***

Process: To add Forecast Employee

- Highlight the activity type
- Click the **Add** button
- Select a forecast employee to add
- Fill in required attributes



Required Attributes

- Company
- Cost Center
- Payroll Calendar
- Personnel Sub-Area
- Activity Type
- Work Schedule
- Pay Scale Area
- Employee Group
- Employee Sub-Group

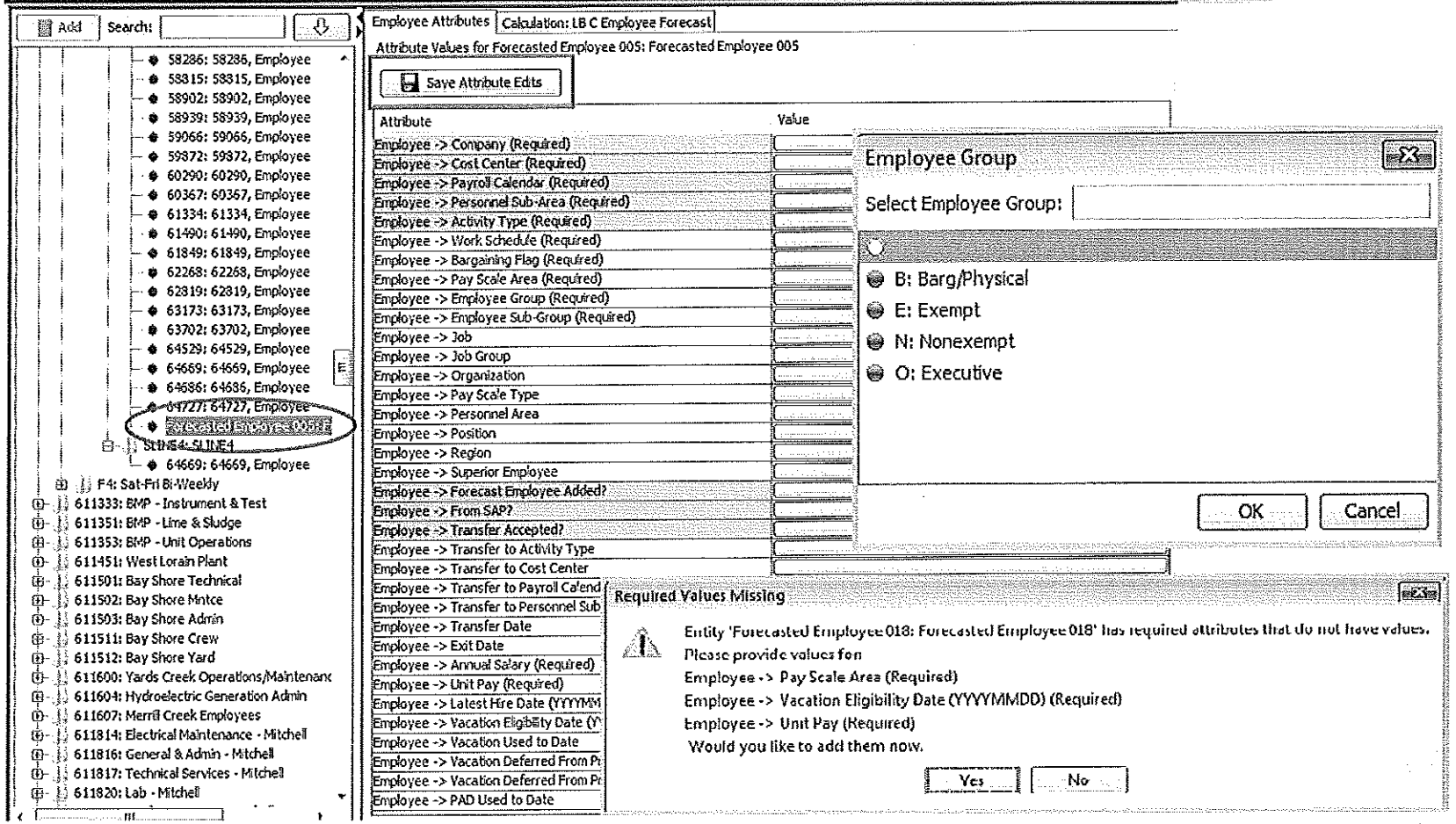
Required Inputs

- Annual Salary
- Unit Pay
- Latest Hire Date (YYYYMMDD)
- Vacation Eligibility Date (YYYYMMDD)

Employee Labor – Add a Forecast Employee

- **Enter all required fields**
  - Searchable drop boxes appear for attributes
  - Monthly Calendars appear for UIPlanner Date fields
  - Type directly into number fields (including SAP date formats – YYYYMMDD)
- Select **Save Attribute Edits** when complete

  Note: An error message will occur if required fields are left blank



Employee Labor – Add a Forecast Employee

- Select the **Calculation: LB C Employee Forecast** tab
- View auto populated data

Employee Attributes | Calculation: LB C Employee Forecast

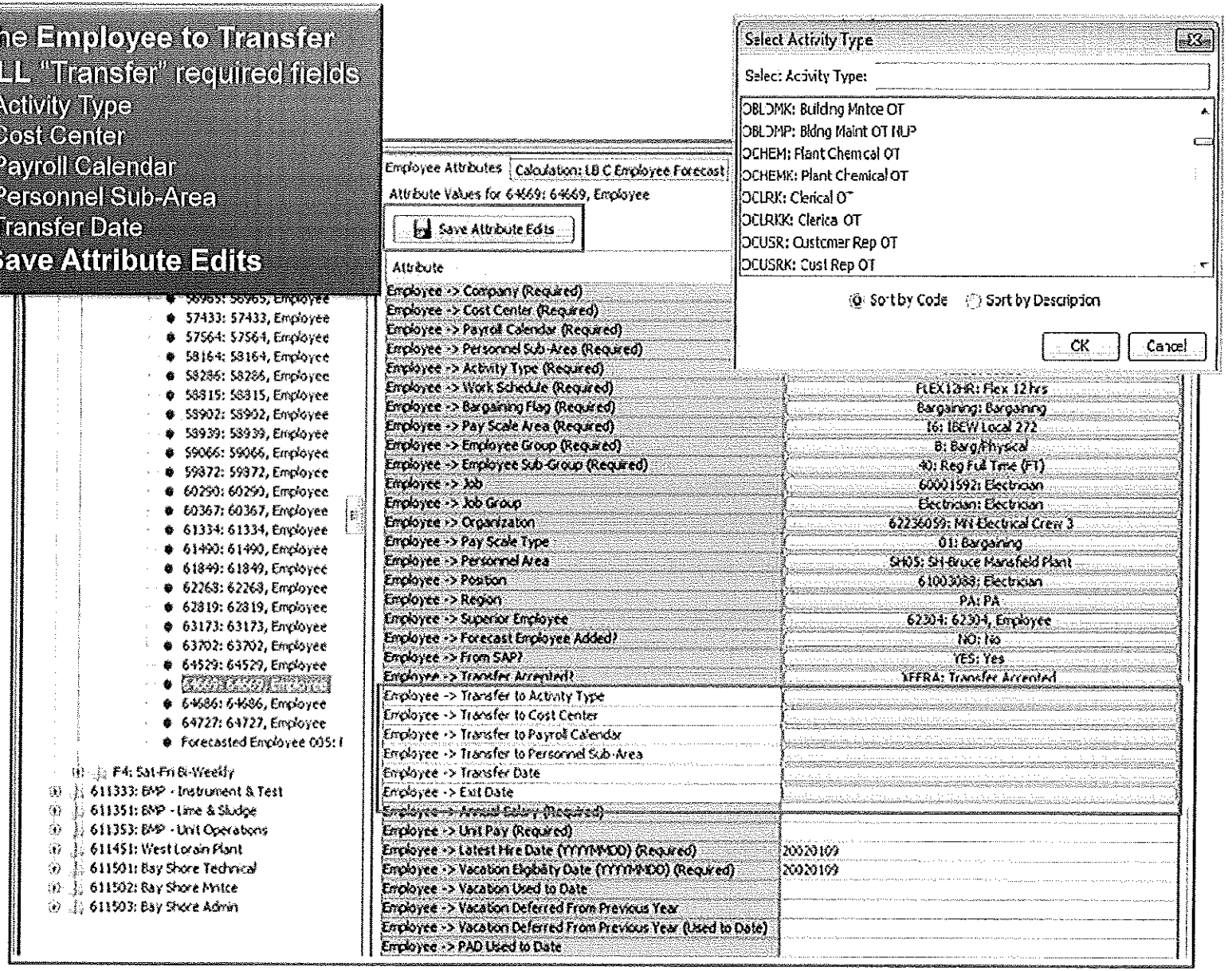
Attribute Values for Forecasted Employee 018: Forecasted Employee 018

Edit	Line: LB C Employee Forecast	Feb 2014	Mar 2014	Apr 2014
	Calculate Employee Headcount			
	Begin Employee Count		1	1
	Employee Added	1		
	Employee Exited			
	Transfer Employee Out			
	Transfer Employee In			
	End Employee Count	1	1	1
	Calculate FTE			
	Begin FTE Count		1.0	1.0
	Initial FTE Count			
	FTE Added	1.0		
	FTE Exited			
	Transfer FTE Out			
	Transfer FTE In			
☑	**FTE Adjustment**			
	Final FTE Count	1.0	1.0	1.0

Line: LB C Employee Forecast	Feb 2014	Mar 2014	Apr 2014	May 2014
Calculate Unit Pay				
Pay Scale Area	IBEW Local ...	IBEW Local ...	IBEW Local ...	IBEW Local ...
Beginning Unit Pay	$25.750	$25.750	$25.750	$25.750
GWI - Wage Increase (%)				
Unit Pay Increase				
Manual Unit Pay Adjustment				
Ending Unit Pay	$25.750	$25.750	$25.750	$25.750
Calculate Monthly Compensation				
Weeks in Month	4	4	4	5
Hours Per Week	40	40	40	40
Total Hours in Month	160	160	160	200
Monthly Compensation (Exempt)				
Monthly Compensation (Hourly)	$4,120	$4,120	$4,120	$5,150
Annual Direct Salary				
Total ST Hours in Year				
Calculate Annual Compensation				
Annual Employee Hours	2,080	2,080	2,080	2,080
Current Month ST Hours	160	160	160	200
Beginning Annual Salary		$53,560	$53,560	$53,560
GWI - Wage Increase (%)				
GWI - Compensation Increase				
Ending Annual Salary	$53,560	$53,560	$53,560	$53,560

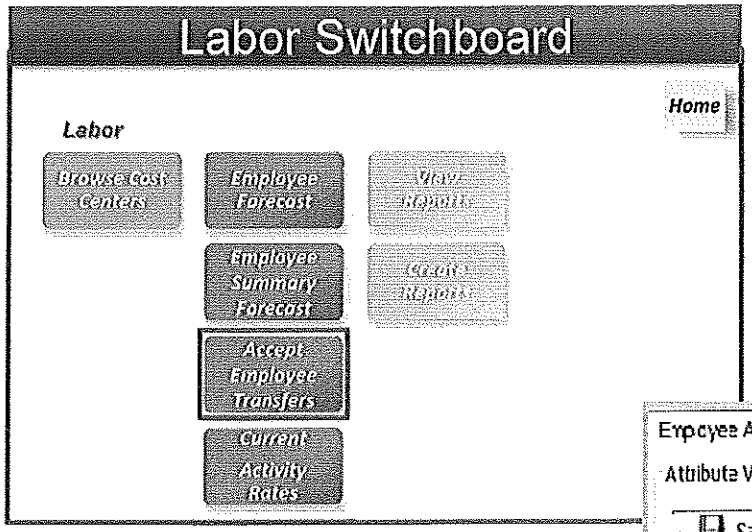
Employee Labor – Transfer Individual Employee

- Select the **Employee to Transfer**
- Enter **ALL** "Transfer" required fields
  - Activity Type
  - Cost Center
  - Payroll Calendar
  - Personnel Sub-Area
  - Transfer Date
- Select **Save Attribute Edits**

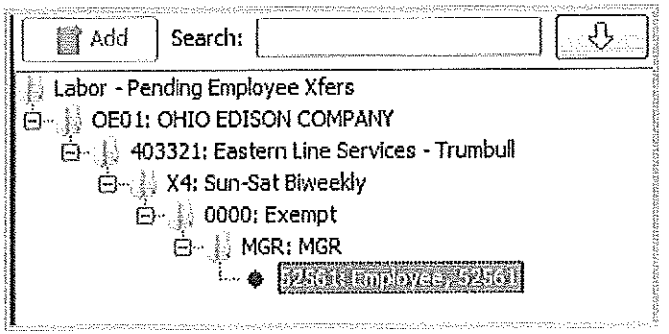


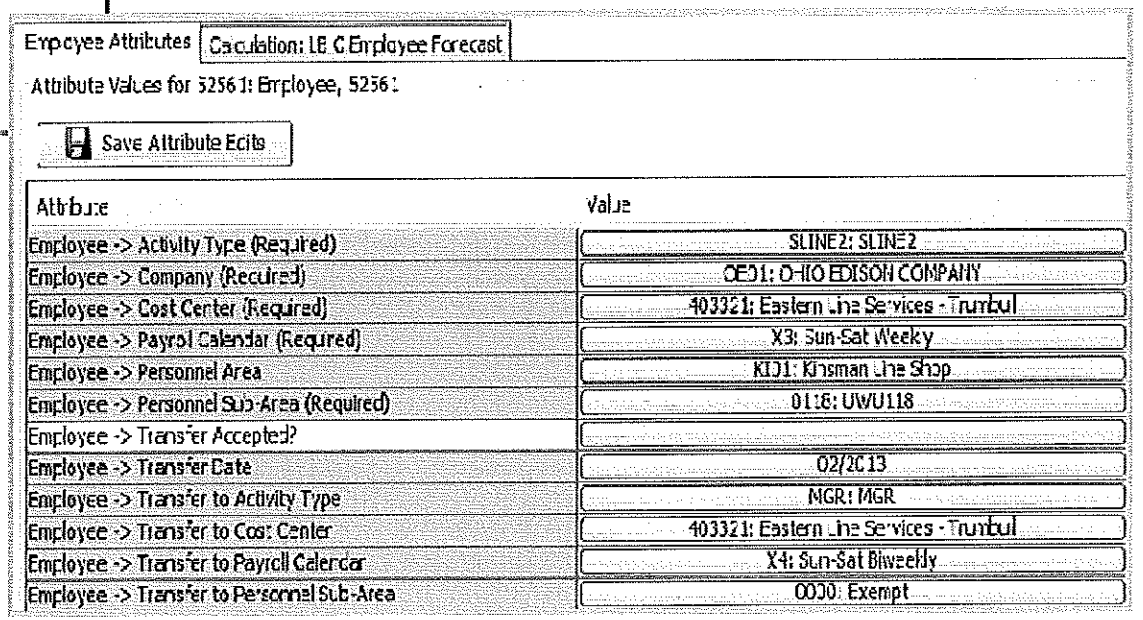
Employee Labor – Transfer Individual Employee

Step 1
- Open the switchboard tab
- Click **Accept Employee Transfers**



Step 2
- Highlight transfer employee
- Select **Yes** to accept transfer
- Select **Save Attributes**





Employee Labor – Verify Transfer

- Select **Employee Forecast** Wrapper
- Employee displays in both old and new cost center
- Record adjusts to reflect transfer date, new pay area and activity type
- Preserves the employee's PAD, Vacation, etc…

Original Record



Edit	Line: LB C Employee Forecast	Apr 2014	May 2014	Jun 2014
	Calculate Employee Headcount			
	Begin Employee Count	1	1	1
	Employee Added			
	Employee Exited			
	Transfer Employee Out			-1
	Transfer Employee In			
	End Employee Count	1	1	
	Calculate FTE			
	Begin FTE Count	1.0	1.0	1.0
	Initial FTE Count			
	FTE Added			
	FTE Exited			
	Transfer FTE Out			-1.0
	Transfer FTE In			
☑	**FTE Adjustment**			
	Final FTE Count	1.0	1.0	

Transfer Record

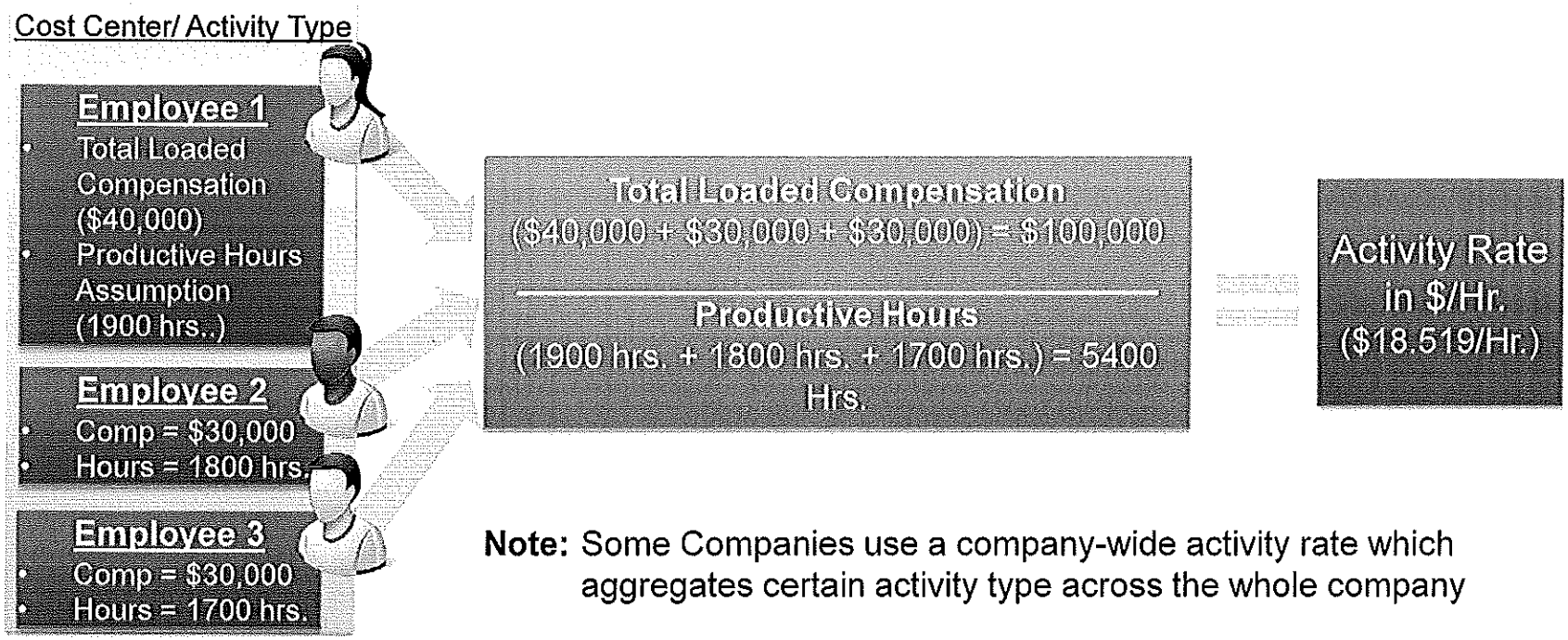


Edit	Line: LB C Employee Forecast	Jun 2014	Jul 2014
	Calculate Employee Headcount		
	Begin Employee Count		1
	Employee Added		
	Employee Exited		
	Transfer Employee Out		
	Transfer Employee In	1	
	End Employee Count	1	1
	Calculate FTE		
	Begin FTE Count		1.0
	Initial FTE Count		
	FTE Added		
	FTE Exited		
	Transfer FTE Out		
	Transfer FTE In	1.0	
☑	**FTE Adjustment**		
	Final FTE Count	1.0	1.0

Employee Labor – Activity Pricing in UIPlanner

Employee Labor – Activity Pricing

Activity Rates are used to allocate labor to projects, orders, and cost centers other than the employees' home center.



Note: Some Companies use a company-wide activity rate which aggregates certain activity type across the whole company

Activity Pricing FAQ

Does Forecasting Vacation Use Affect Activity Rates?

No. The unproductive time in the Activity Pricing Calculation uses assumptions for unproductive time including assumed meeting hours and utilization of all vacation & PAD earned in a year.

Does Adding Compensation Affect Activity Rates?

It depends. If a future raise or promotion for an employee is known, it could be added to the employee prior to the activity pricing process. However, forecast compensation changes made during the annual budget process or reforecasting will not affect rates

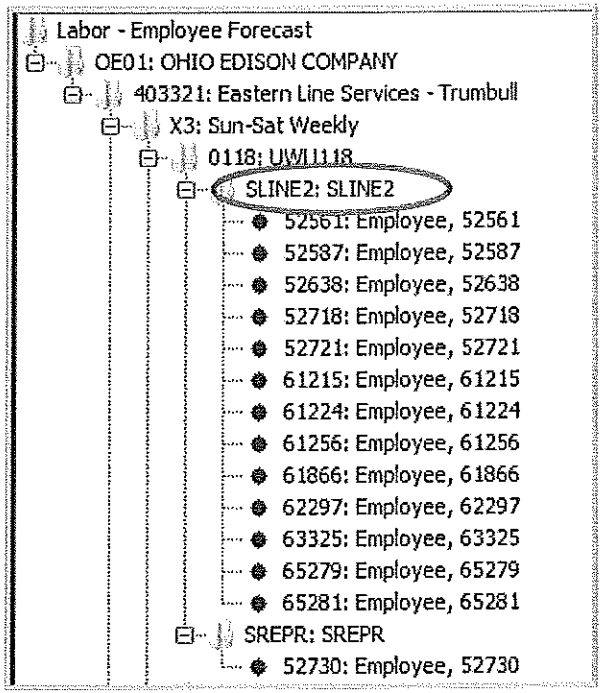
Does Adding an Employee Affect Activity Rates?

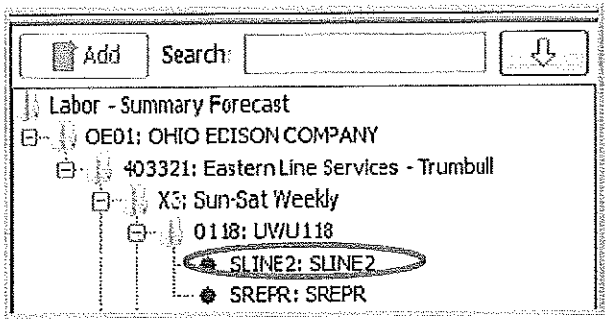
No. Activity Rates are set and published prior to users being able to edit and add employees

Employee Labor – Summary Forecast

Employee Labor – Summary Forecast

Employee Summary wrapper summarizes individual employee information to the cost center activity type level for each cost center

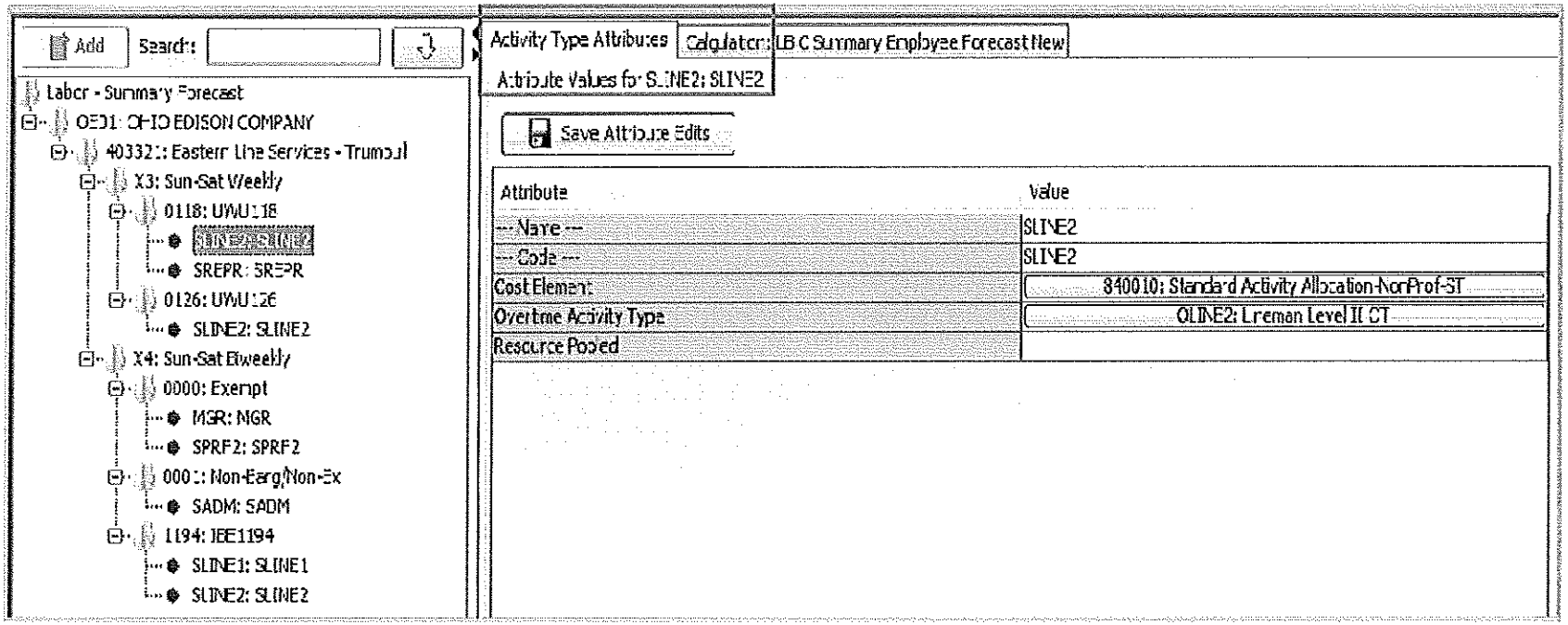




Information related to SLINE2 activity type is summarized in the Employee Summary wrapper

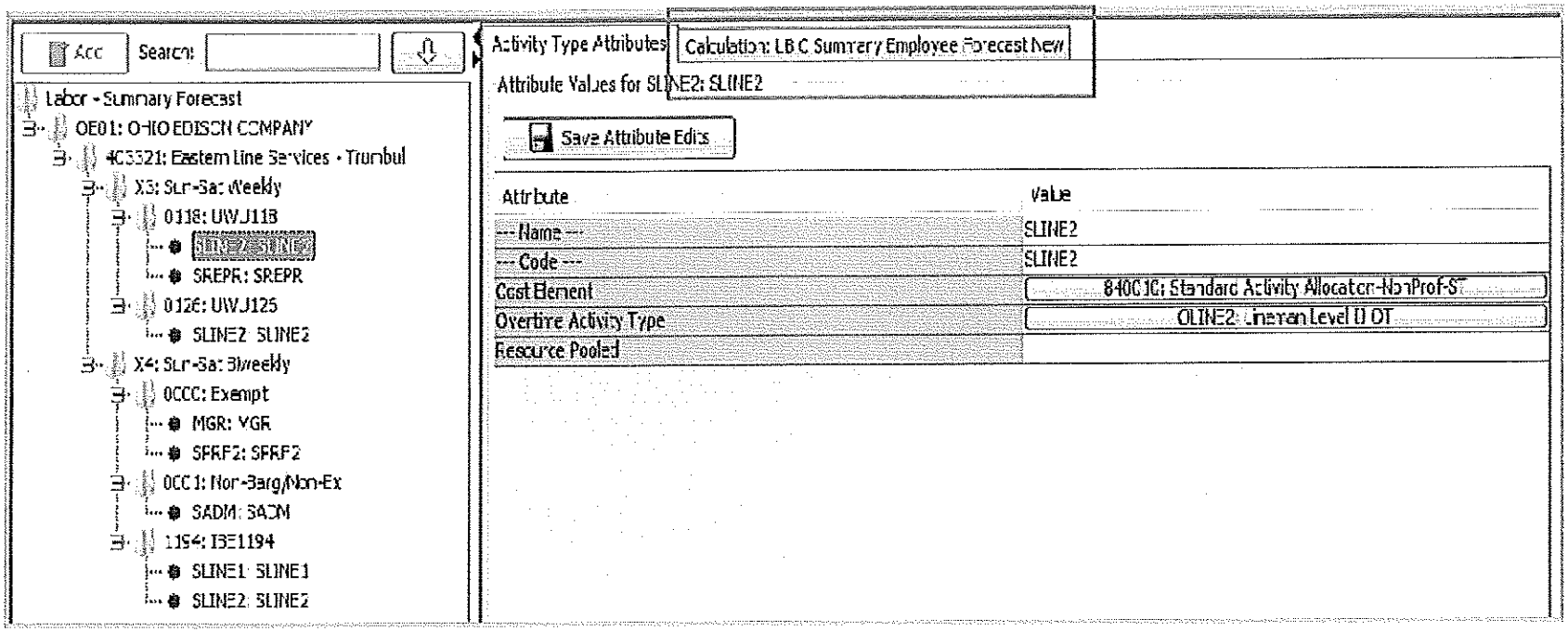
Employee Labor – Summary Forecast

- Select **Activity Type Attributes**
- Information auto populated



Employee Summary

Select **Summary Employee Forecast**



To add a new activity type to a cost center either:

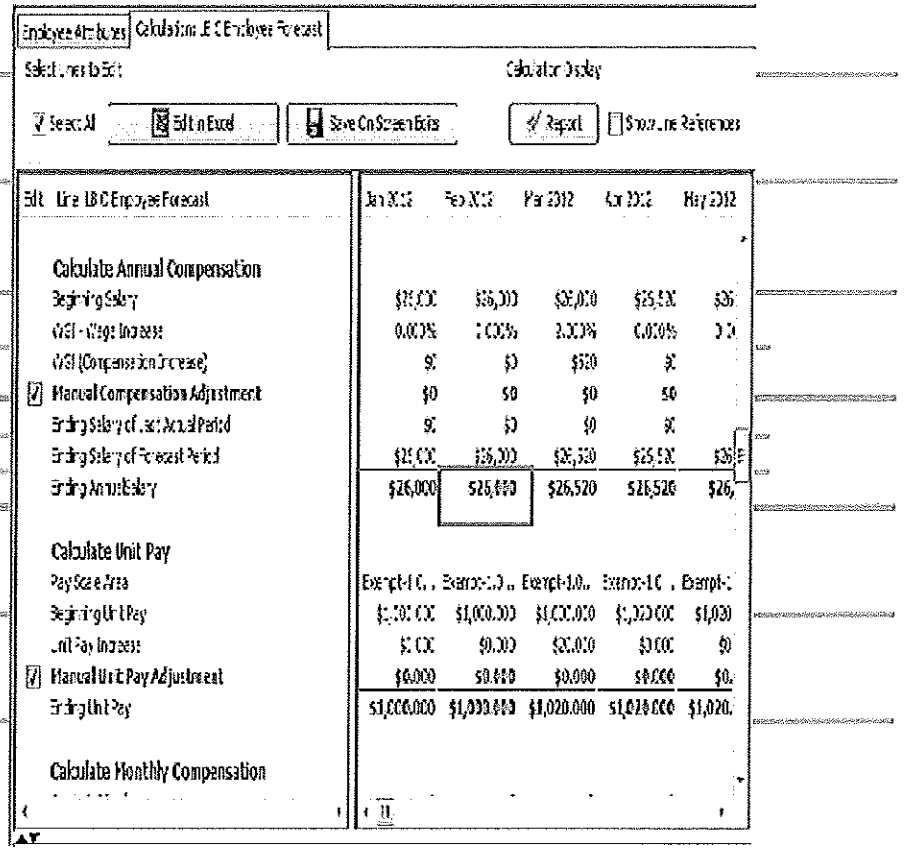
- Add a forecast employee with the desired Cost Center/Activity Type combination
- **Transfer an employee into the Cost Center/Activity Type combination (if the new combo occurs as a result of a transfer)**

Employee Summary – Calculations (Overview)

Summary Forecast Calculations

1. Headcount & FTE
2. PAD
3. Vacation
4. Vacation Deferred
5. Compensation
   - a. Monthly Compensation
   - b. Annual Compensation
6. Loadings (Admin Maintained)
   - a. Incentive Compensation Plan
   - b. Payroll Tax
   - c. Benefits Loading
7. Bonuses
8. Straight Time Hours (for Budget Grid)
9. Overtime Dollars (for Budget Grid)

- Select the Calculation Tab
- Listed are the key data fields and activity price calculation
- Only rows highlighted in yellow can be edited



Employee Summary

1 Calculate Headcount & FTE Level

- Summary wrapper summarizes data from employee wrapper by cost center, pay area and activity type
- Information auto populated
- Similar to the employee forecast wrapper, users can edit rows highlighted in yellow

Edit	Line: LB C Summary Employee Forecast...	Apr 2014	May 2014	Jun 2014
	Calculate Employee Count			
	Begin Headcount	3	3	3
	Employee Forecast Headcount Change			
☑	**Regular FT Headcount Change**			
☑	**Regular PT Headcount Change**			
☑	**Student/Intern Headcount Change**			
☑	**Temporary Employee Headcount C...**			
	End Headcount	3	3	3
	Calculate FTE Count			
	Begin FTE Count	3.00	3.00	3.00
	+ Employee Forecast FTE Change			
☑	**Regular FT FTE Change**			
☑	**Regular PT FTE Change**			
☑	**Student/Intern FTE Change**			
☑	**Temporary Employee FTE Change**			
	End FTE Count	3.00	3.00	3.00

Employee Summary – Available Hours for Grid

2. Calculate PAD
3. Calculate Vacation
4. Calculate Vacation Deferred

Edit	Line: LB C Summary Employee Forecast...	Apr 2014	May 2014	Jun 2014
	PAD Forecast			
	Beginning PAD Available	96	96	96
	+ PAD Allocation			
	+ Change in PAD Allocation from EF Tran...			
☑	**+ Additional PAD Allocation**			
	- Actual PAD Used			
	- Employee Forecast PAD Use			
☑	**- Forecasted PAD Use**			
	End Available PAD Hours	96	96	96
	Vacation Forecast (VPAD)			
	Beginning Vacation Available	360	360	360
	+ Vacation Allocation			
	+ Change in Vacation Allocation from EF ...			
☑	**+ Additional Vacation Allocation**			
	- Actual Vacation Used			
	- Employee Forecasted Vacation Use			
☑	**- Forcasted Vacation Use**			
	End Available Vacation Hours	360	360	360
	Vacation Deferred Forecast			
	Begining Vacation Deferred Available	64	64	64
	+ Vacation Deferred Allocation from Empl...			
	+ Change in Vacation Deferred Allocatio...			
☑	**+ Additional Vacation Deferred Allo...**			
	- Actual Vacation Deferred Used to Date			
	- Employee Forecasted Vacation Deferre...			
☑	**- Forecasted Vacation Deferred Use**			
	End Available Vacation Deferred Hours	64	64	64

Employee Summary – Compensation

5 Compensation

Edit	Line: LB C Summary Employee Forecast...	Apr 2014	May 2014	Jun 2014
	Calculate Monthly Compensation			
	Weeks in Month	4	4	4
	Pay Periods in Month	2	2	2
	GWI - Wage Increase			
	Hours/Week per FTE	40	40	40
	Initial Direct Compensation	$32,892	$32,892	$32,892
	Employee Direct Compensation Increase			
	Compensation Change due to FTE Change			
	Adjusted Previous Manual Direct Compen...			
☑	**Manual Direct Compensation Incre...**			
	Direct Compensation Available for Budge...	$32,892	$32,892	$32,892
	Annual Direct Compensation			

Employee Summary – Compensation

6 Loadings

Edit	Line: LB C Summary Employee Forecast...	Apr 2014	May 2014	Jun 2014
	Compensation Loadings			
6a	**Incentive Compensation Loading**			
	Monthly Compensation	32,892	32,892	32,892
	* Incentive Compensation Loading (%)	10.00%	10.00%	10.00%
	Incentive Compensation Allocated	$3,289	$3,289	$3,289
6b	**Compensation Tax Loading**			
	Direct Compensation	$32,892	$32,892	$32,892
	* Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	Payroll Tax for Direct Compensation	$2,480	$2,480	$2,480
	Incentive Compensation	$3,289	$3,289	$3,289
	* Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	Payroll Tax for ICP	$248	$248	$248
	Payroll Tax for Direct Compensation	$2,480	$2,480	$2,480
	Payroll Tax for ICP	$248	$248	$248
	Payroll Tax Allocated	$2,728	$2,728	$2,728
6c	**Benefits Loading**			
	Direct Compensation	$32,892	$32,892	$32,892
	* Benefits Loading (%)	22.14%	22.14%	22.14%
	Benefits Allocated	$7,282	$7,282	$7,282

Employee Summary – Compensation

6 Loading *Percentages*

Edit	Line: LB C Summary Employee Forecast...	Oct 2014	Nov 2014	Dec 2014
6a	**Benefits Loading**			
	Direct Compensation	$32,892	$32,892	$32,892
	* Benefits Loading (%)	22.14%	22.14%	22.14%
	Benefits Allocated	$7,282	$7,282	$7,282
6b	**Total Compensation Loadings**			
	Incentive compensation Loading (%)	10.00%	10.00%	10.00%
	+ Payroll Tax Loading (%)	7.54%	7.54%	7.54%
	+ Payroll Tax Loading (%) * ICP (%)	0.75%	0.75%	0.75%
	+ Benefits Loading (%)	22.14%	22.14%	22.14%
	Total Loading Percent	40.43%	40.43%	40.43%
6c	**Loaded Monthly Compensation**			
	Incentive compensation Allocated	$3,289	$3,289	$3,289
	+ Payroll Tax Allocated	$2,728	$2,728	$2,728
	+ Benefits Allocated	$7,282	$7,282	$7,282
	Total Loading Dollars	$13,300	$13,300	$13,300
	+ Monthly Direct Compensation	$32,892	$32,892	$32,892
5a	Loaded Monthly Compensation	$46,191	$46,191	$46,191
5b	Loaded Annual Compensation			**$598,224**

***Note:** Annual Totals only appear in December*

Employee Summary – Compensation

7 Bonuses

Bonuses are entered in the Bonus line, and Payroll Tax for Bonus Compensation is calculated to yield Total Bonus Compensation

Edit	Line: LB C Summary Employee Forecast...	Oct 2014	Nov 2014	Dec 2014
	Bonus Compensation			
	Employee Forecast Bonus Compensation			
☑	**Bonus Compensation**	$1,000		
	Total Bonus Compensation	$1,000		
	* Payroll Tax Loading	7.54%	7.54%	7.54%
	Bonus Compensation Payroll Taxes	$75		
	+ Total Bonus Compensation	$1,000		
	Total Loaded Bonus Compensation	$1,075		

Employee Summary – Compensation

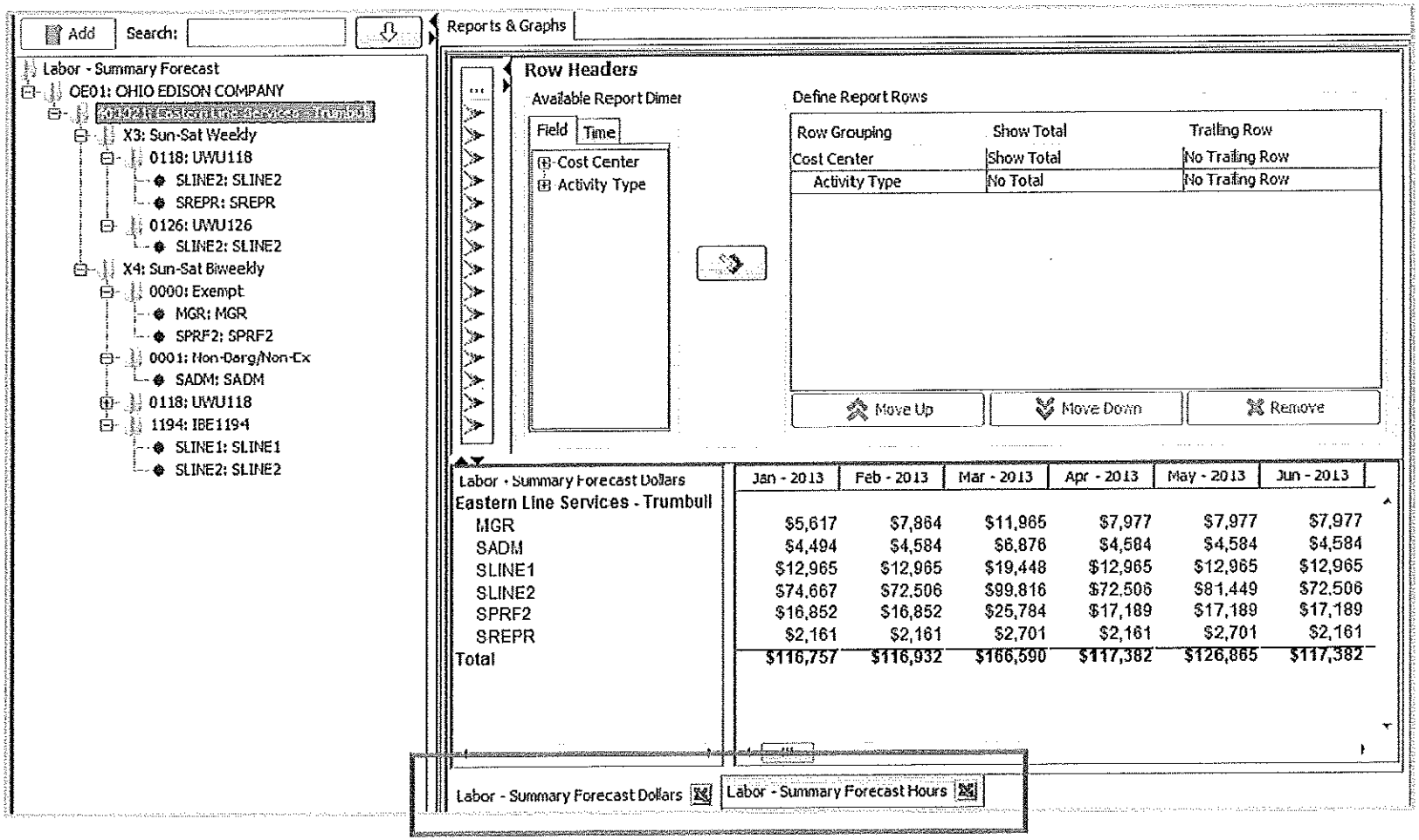
8 Straight Time Hours for Budget Grid

9 Overtime Dollars for Budget Grid

Edit	Line: LB C Summary Employee Forecast...	Jan 2014	Feb 2014	Mar 2014	Apr 2014
	Budgeting				
	Payroll Calendar				
	Weeks in Month	6	4	4	4
	Pay Periods in Month	3	2	2	2
	FTE	5	5	5	5
	Hours Available for Budgeting				
	Total ST Hours in Month	1,200	800	800	800
	+ ST Hours due to Change in FTE				
	- PAD Hours Used				
	- Vacation Used				
	- Vacation Deferred Used				
	- Holiday Hours	120			
	- Holiday Hours due to Change in FTE				
	- Miscellaneous Unproductive Hours in Bu...				
☑	**- Miscellaneous Unproductive Hour...**			**120**	
	Hours Available for Budgeting	1,080	800	680	800
	Overtime Budgeting				
	Activity Price				
	Overtime Activity Type	Prof Level II...	Prof Level II...	Prof Level II...	Prof Level II...
	Overtime Activity Price	$67.113	$67.113	$67.113	$67.113
	Budget Overtime				
☑	**Overtime Hours**	**120.0**			
	* Overtime Activity Rate	$67.113	$67.113	$67.113	$67.113
	Overtime Dollars	$8,054			

Employee Summary – Wrapper Reports

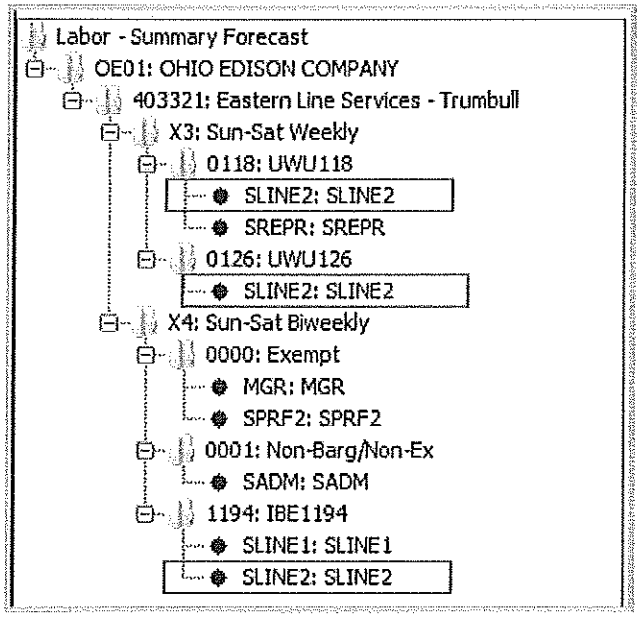
- View total hours and dollars by activity type at the cost center level
- Report will be view only



Employee Summary to Budget Grid

- The grid is used to allocate hours and dollars
- If labor is not activity allocated, then labor dollars will not show on the grid. Information is available via report

Cost Source	Cost Owner	Cost Collector Ty	Project	WBS	Internal Order	Activity Type	Cost Element	Comment	Amount Type	2013
Filter Off	Filter Off	Filter Off	Filter Off	...	Filter Off	Filter On	Filter Off			2013 - Jan
403321: Eastern L	401221: Centra	WBS	WBS	OE-900083: N-Line	OE-9000	N/A: N/A	SLINE: Lineman-a	840010: Stand		
									Dollars	$5,193
									Hours	95.0



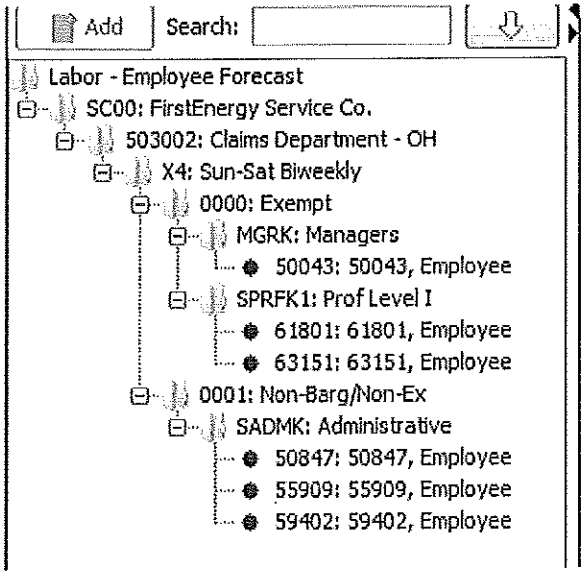
Column Totals	Dollars	$247,939
	Hours	4,583.8
Available Amounts	Available Hours	0.0

- Subtotal for SLINE2 will display and total on the available amounts row
- As hours are activity allocated out the available hours row will adjust

Budget Grid - How to Handle Labor Dollars/Hours

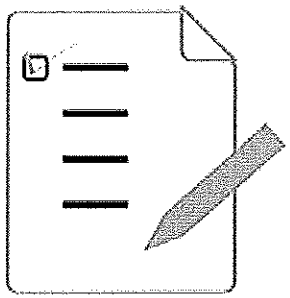
After the labor pool has been built:

- View the labor and hour report which will show the total calculated hours and dollars by activity type for each cost center
- Open the Budget Grid:
  - If labor has been allocated from your cost center, verify that the total labor pool matches the pool calculated in the **Summary Forecast**
  - Next users can start activity allocating labor hours and dollars.



Note: The Budget Grid is only for allocating hours and dollars. It will not show the labor dollars and hours allocated to the primary cost center.

Exercise #5 – Employee Labor



- Select a cost center and review an individual employee labor profile

- Under the Employee Attribute tab:
  - Transfer an employee
  - Exit an employee

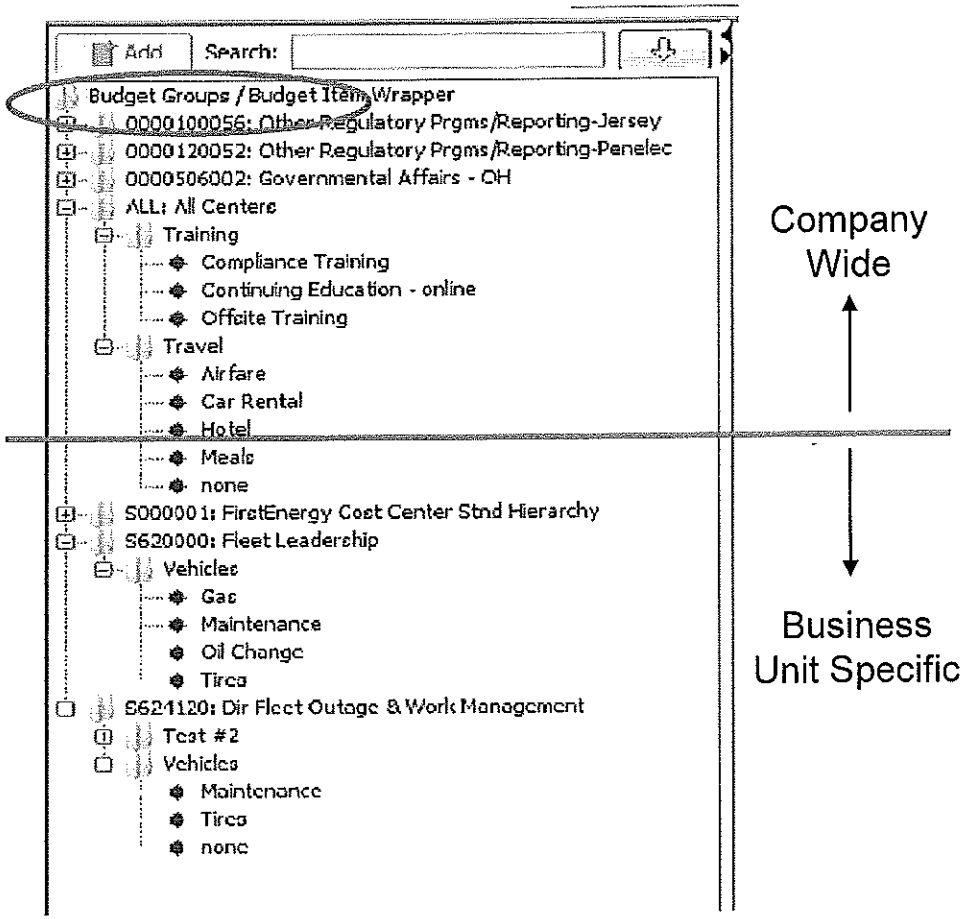
- Under the Calculation: Labor Budget Employee Forecast
  - Add a salary adjustment on the screen
  - Enter vacation and PAD allocations

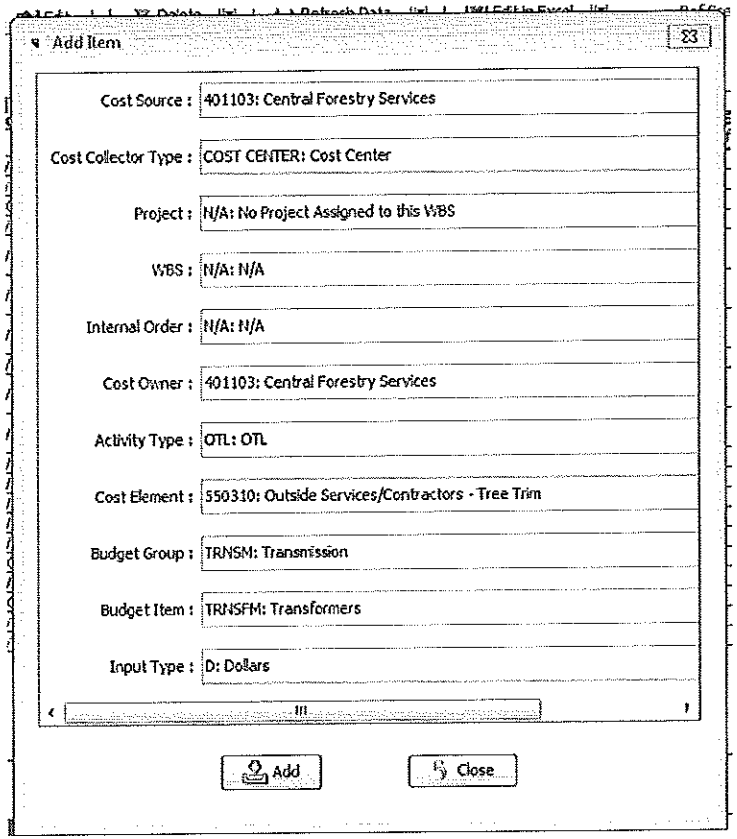
- View Summary Wrapper
  - Add a salary adjustment on the screen
  - Enter vacation and PAD allocations

Budget Group / Budget Item Wrapper

Budget Group / Budget Item Wrapper Overview

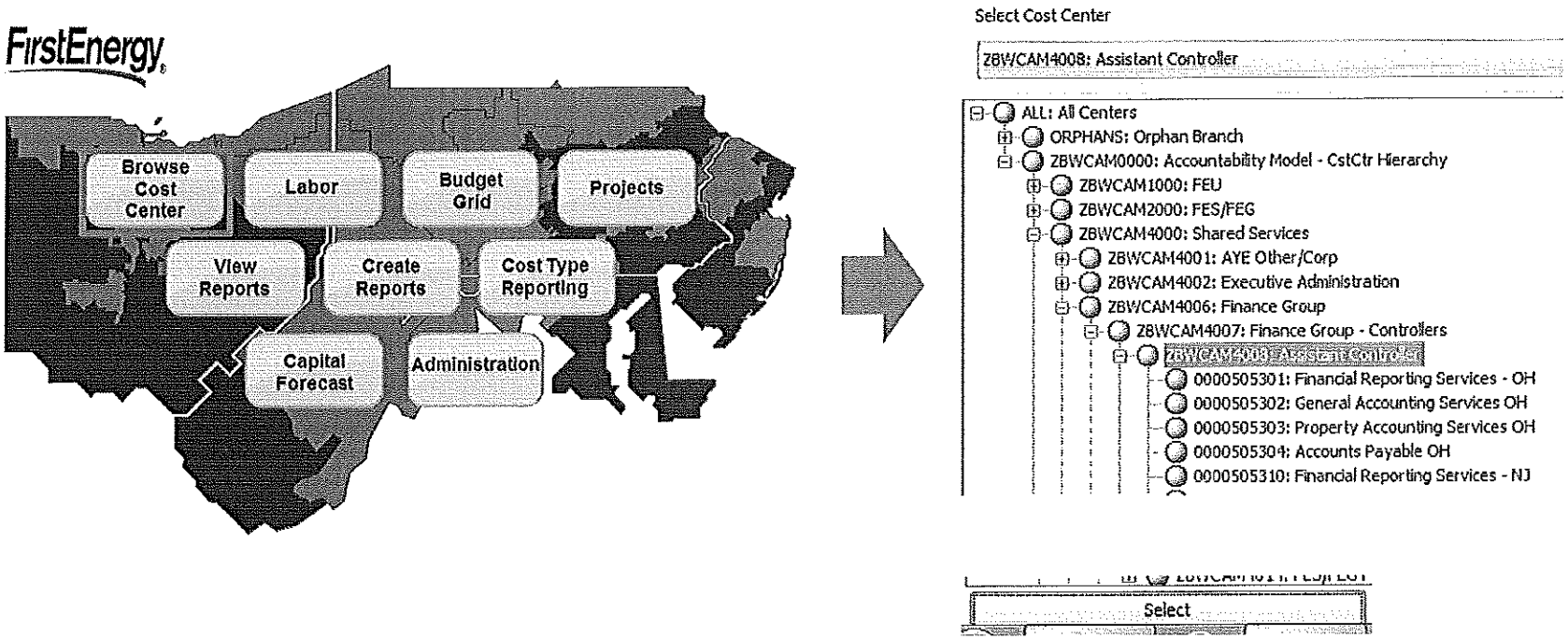
- Standard Budget Group and Budget Item groupings will be made available for all users
- Specific business unit budget groups and items can easily be created
- Ability to create Budget Group and Budget Item at the Cost Center level
- Business Unit/Department Budget Coordinators will create and maintain Budget Groups and Budget Items for their areas





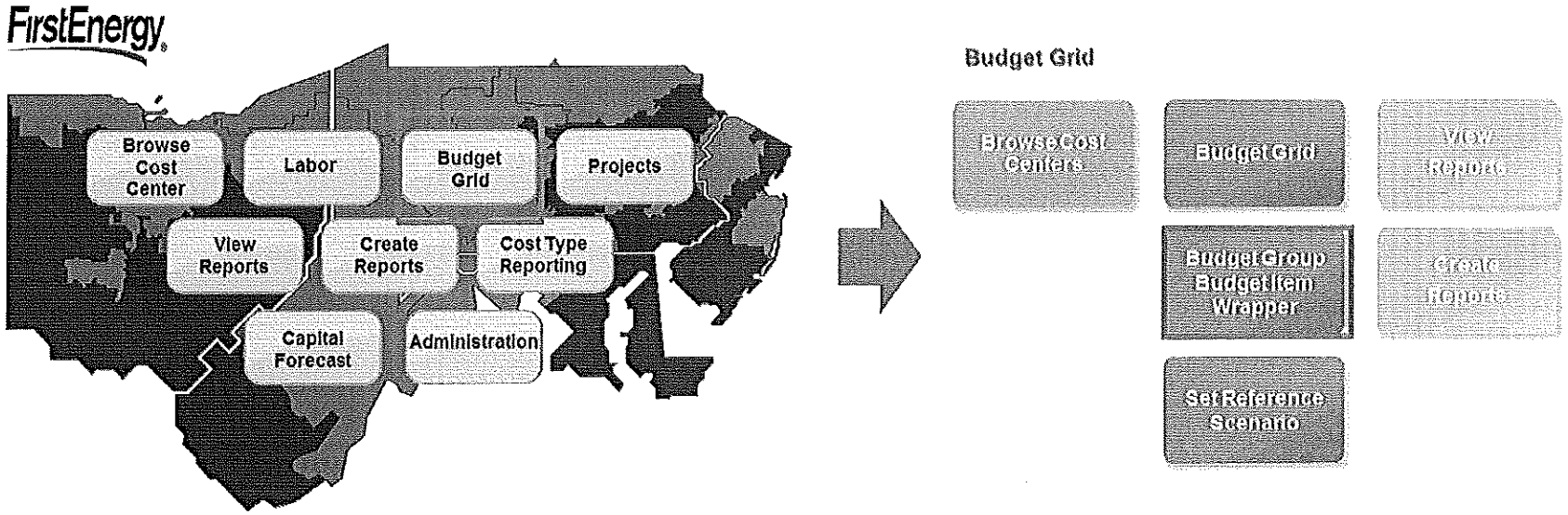
Budget Group / Budget Item Wrapper Startup

1. Using the Budget Group/Budget Item Wrapper
   - Open **FE Main Switchboard**
   - Select a Cost Center using **Browse Cost Centers** (either double-click a Cost Center or highlight Cost Center and click the Select button at the bottom of the screen)
   - NOTE: Any Budget Group/Budget Item assigned to a rollup node will be available for use for any Cost Center children of this node



Budget Group / Budget Item Wrapper Startup

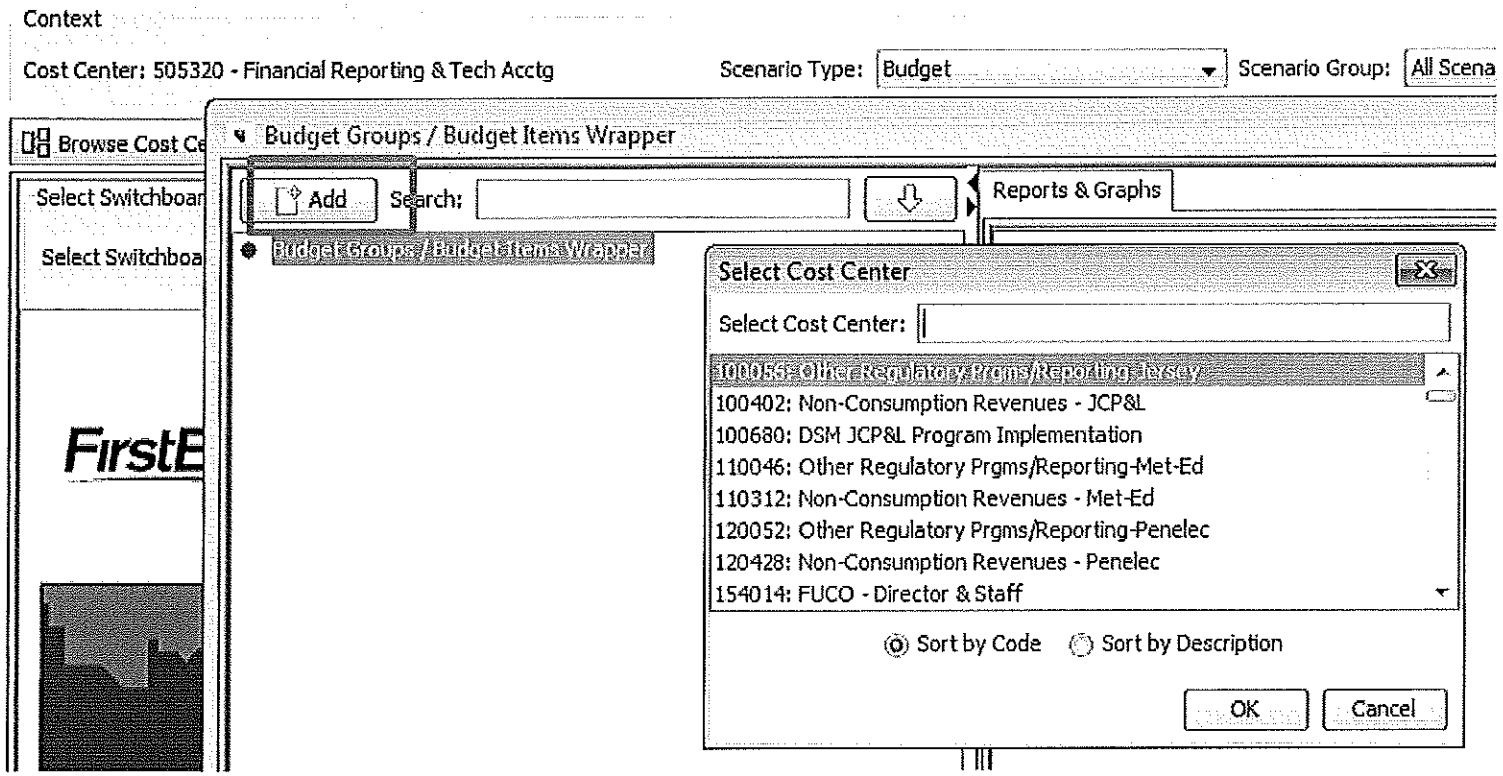
2
- Return to the **FE Main Switchboard**
- Click **Budget Grid**
- Click **Budget Group Budget Item Wrapper**



Adding a Cost Center

3

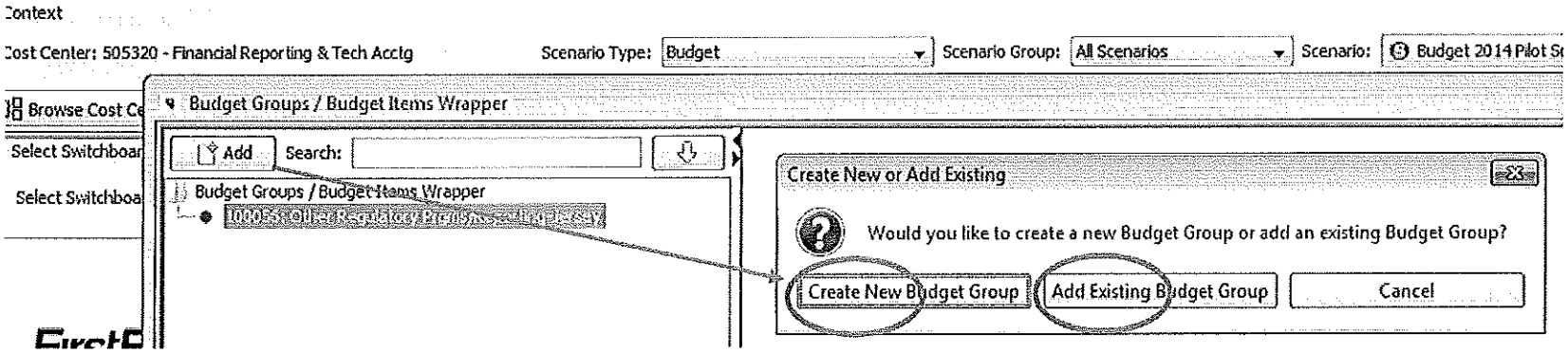
- If the Wrapper Tree is empty and no Cost Center is readily available, select "Budget Groups / Budget Items Wrapper" and click on the Click the **Add** button.
- Scroll through the list of Cost Centers and select one (use Select Cost Center window to search). Click **OK** when finished.



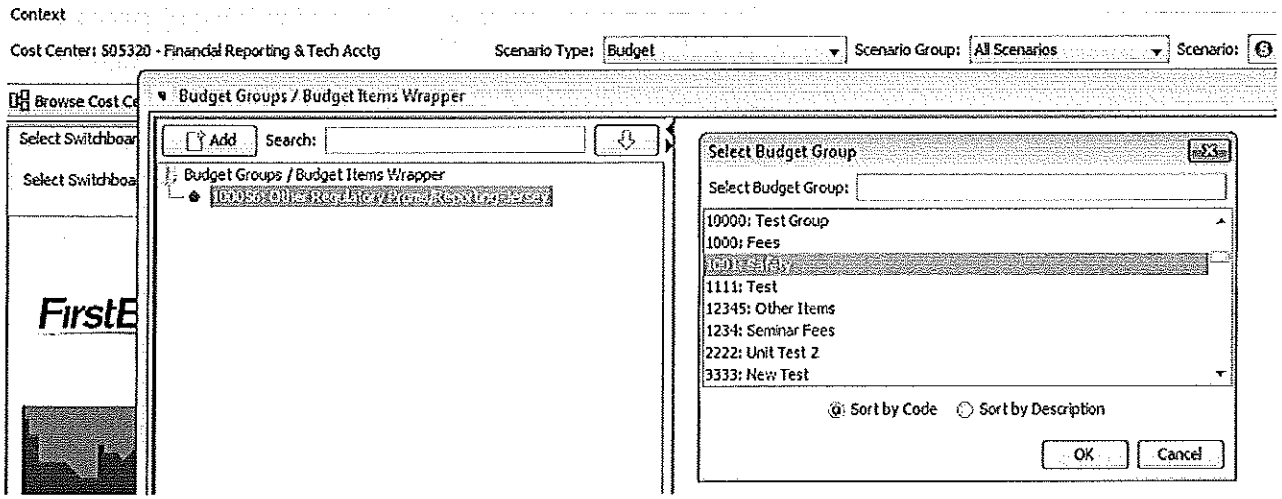
Add Existing Budget Group

4

- Select the Cost Center where a Budget Group and its associated Budget Item will be added and click **Add** button.
- Select either "Create New" or "Add Existing" Budget Group.



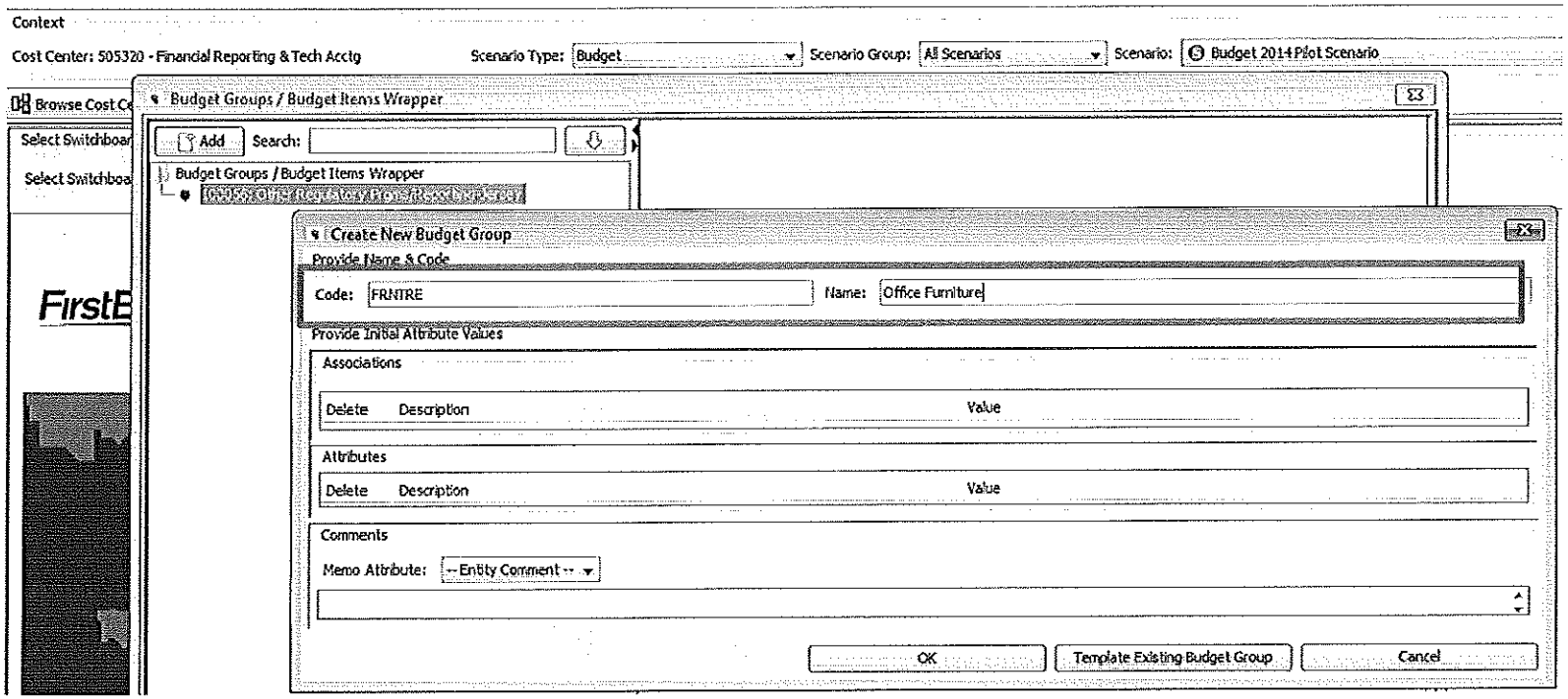
- If adding an existing Budget Group, simply select from the popup window and click **OK**.



Create a New Budget Group

4

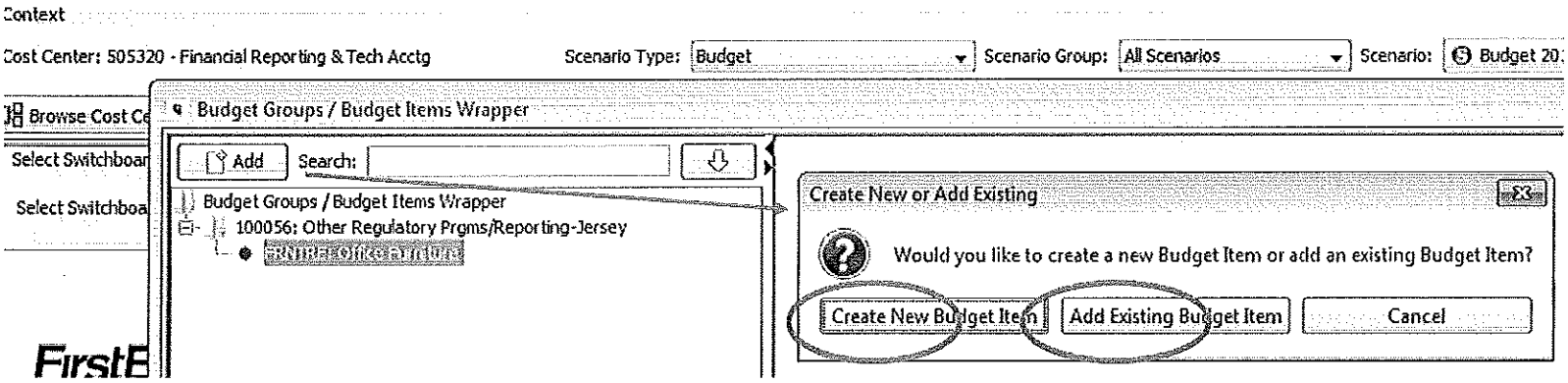
- Enter a unique Budget Group Code using process as defined by FE.
- Enter Name of Budget Group (MAX length = 80 characters)
- Click **OK**.



Adding / Creating Budget Items

5

- Follow a similar process for creating or adding Budget Items
- NOTE: Budget Items must have an associated Budget Group



Budget Group / Budget Item Guidelines

- Budget Coordinators will have the ability to create Budget Groups Budget and Items for their respective areas

Guidance on codes and names

• **Budget Group Budget Item Codes**	• **ALL CAPS** • **Up to 12 alpha characters**
• **Budget Group Budget Item Descriptions**	• **Upper and lower case** • **Up to 80 characters in length**

Example

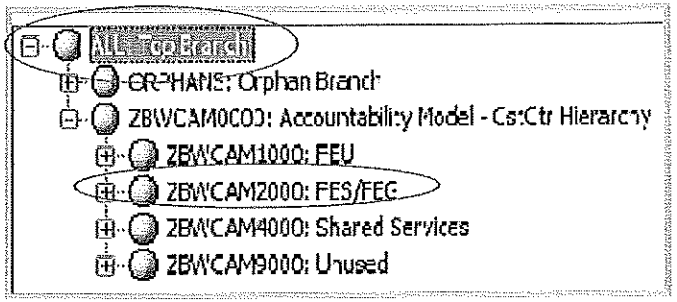
Budget Group	• **TRAIN**	**Training**
Budget Items	• SAFETY	Safety
	• COMPL	Compliance
	• OPER	Operations
	• CONTEDU	Continuing Education

Avoid creating similar Budget Groups and Budget Items

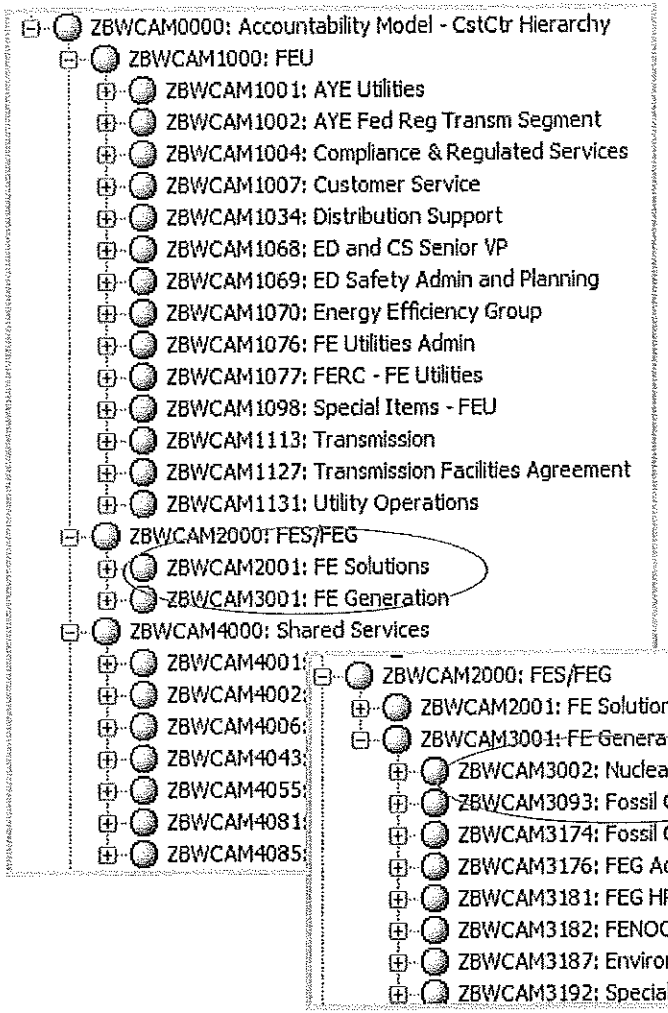
- Codes should be meaningful so when the accounting name is turned off on the Budget Grid the user can easily identify the Budget Group and Budget Item

Budget Group / Budget Item Guidelines

1. Budget Group / Budget Items will be created at the ALL NODE (created by Budget Administrator) and the Business Unit level (created by the Budget Coordinator)



2. Budget Groups / Budget Items can also be created at the <u>second</u> and <u>third</u> levels of the cost center tree



Note:

- **<u>DO NOT</u>** create budget groups and budget items at the cost center level

Normalizing Entries

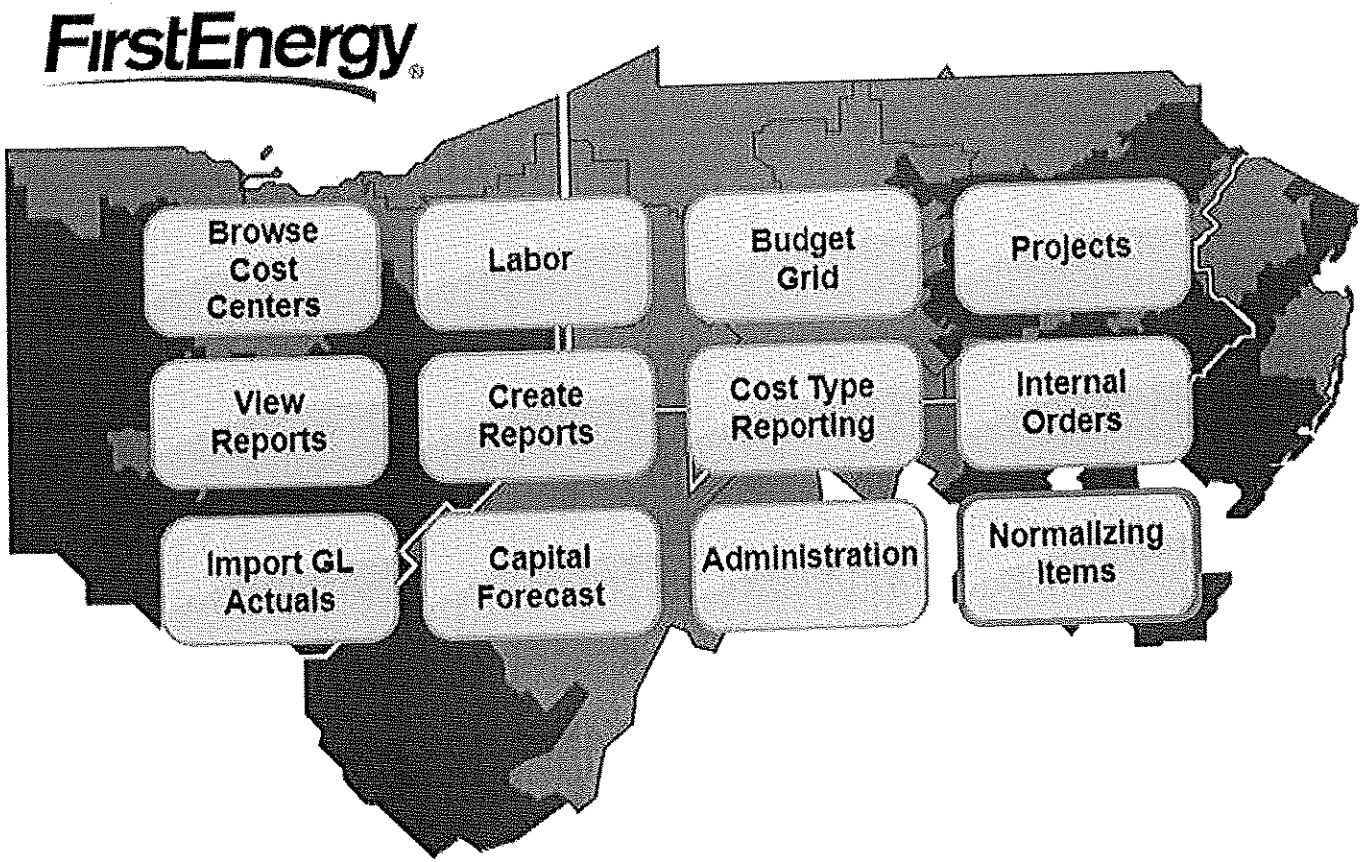
Normalizing Items

- **Normalizing Items**
  - Separate grid for normalized items
  - Normalized items will be applied to budget <u>after</u> closing process
  - GAAP budget and normalized items will be sent to the model, taxes will then be calculated by the model
  - Normalized budget will then be sent to BW

Note: The new budget entry process in UIP will be on a GAAP basis

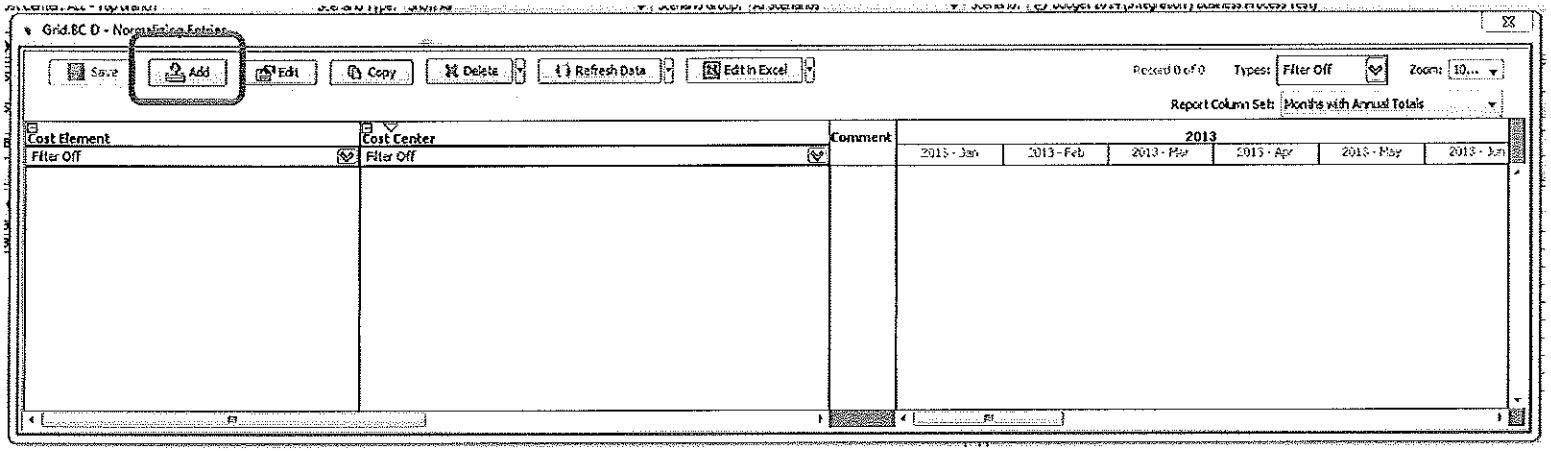
Normalizing Items

- From the Switchboard, select 'Normalizing Items'

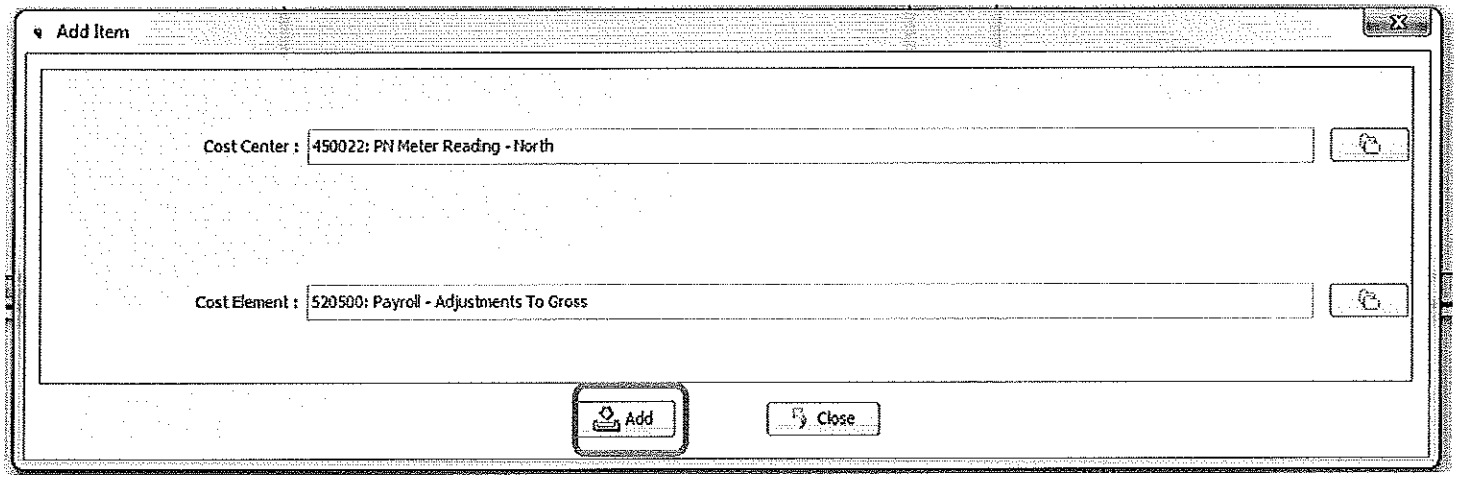


Normalizing Items

- The window below will open from the switchboard. Click Add to assign the code block.

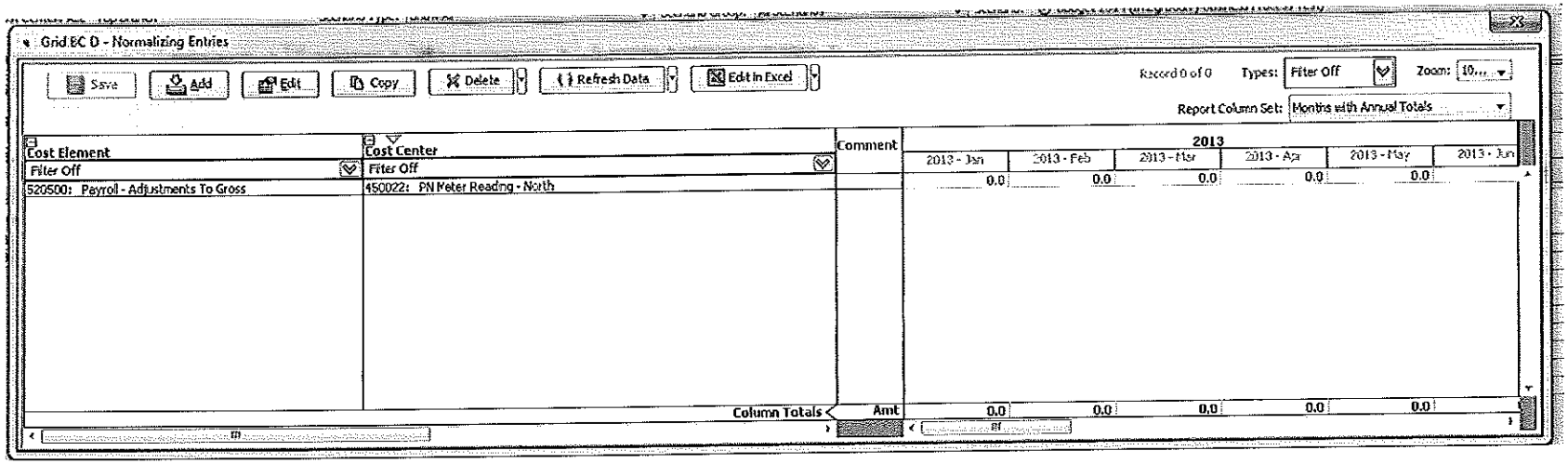


- Users can assign the Cost Center and Cost Element. Then click Add to save to grid.



Normalizing Items

- The new code block combination will be applied to the grid
- User can then update dollars in grid for entries



- Or, users can Edit in Excel to add rows…just like the usual grid.

Reference Materials

Commonly Used Terms in UIPlanner

Attribute
- Facts about an entity. Attributes are assigned to the Entity Group. Attribute data is then entered for each entity

B2
- The internal name given to the multidimensional calculation budget system when it was first developed (UIPlanner's second generation budget system)

Codeblock
- Codeblock consists of the budget grid data fields (cost source, cost owner, cost collector type, cost element, activity type, etc.)

Combo
- A budget data entry, comprised of the required code block elements

Cost Owner
- Owning cost center of the cost collector

Cost Source
- Cost Center where employee labor resides

Entities
- Building blocks for structured data within UIPlanner. Entities are specific elements of an Entity Group. Example: Generation plants are "Entities" in the Generation Entity Group

Commonly Used Terms in UIPlanner

Financial Model
- UIPlanner's modeling tool. Generates the key financial statements (income statement, balance sheet, cash flow)

Grid
- Budget Grid where users can allocate labor and other than labor. The Grid requires valid codeblock for entry

Java Console
- Java window that echoes back information about the user's UIPlanner session, including java error messages. Also known as the Stack Trace

Menu Item
- Row at the top of the UIPlanner screen contains menu items. Each menu item contains a drop list of screens or options

Scenario
- Scenarios are essentially collections of cases. Similar to SAP versions (V20, V12, etc.), but can be in various formats (Name, Description, etc.)

Switchboard
- Graphical object with hotspots that invoke actions in UIPlanner. Hot-spott areas on a switchboard and can open menu items, run reports, open files, and open other switchboards

Commonly Used Terms in UIPlanner

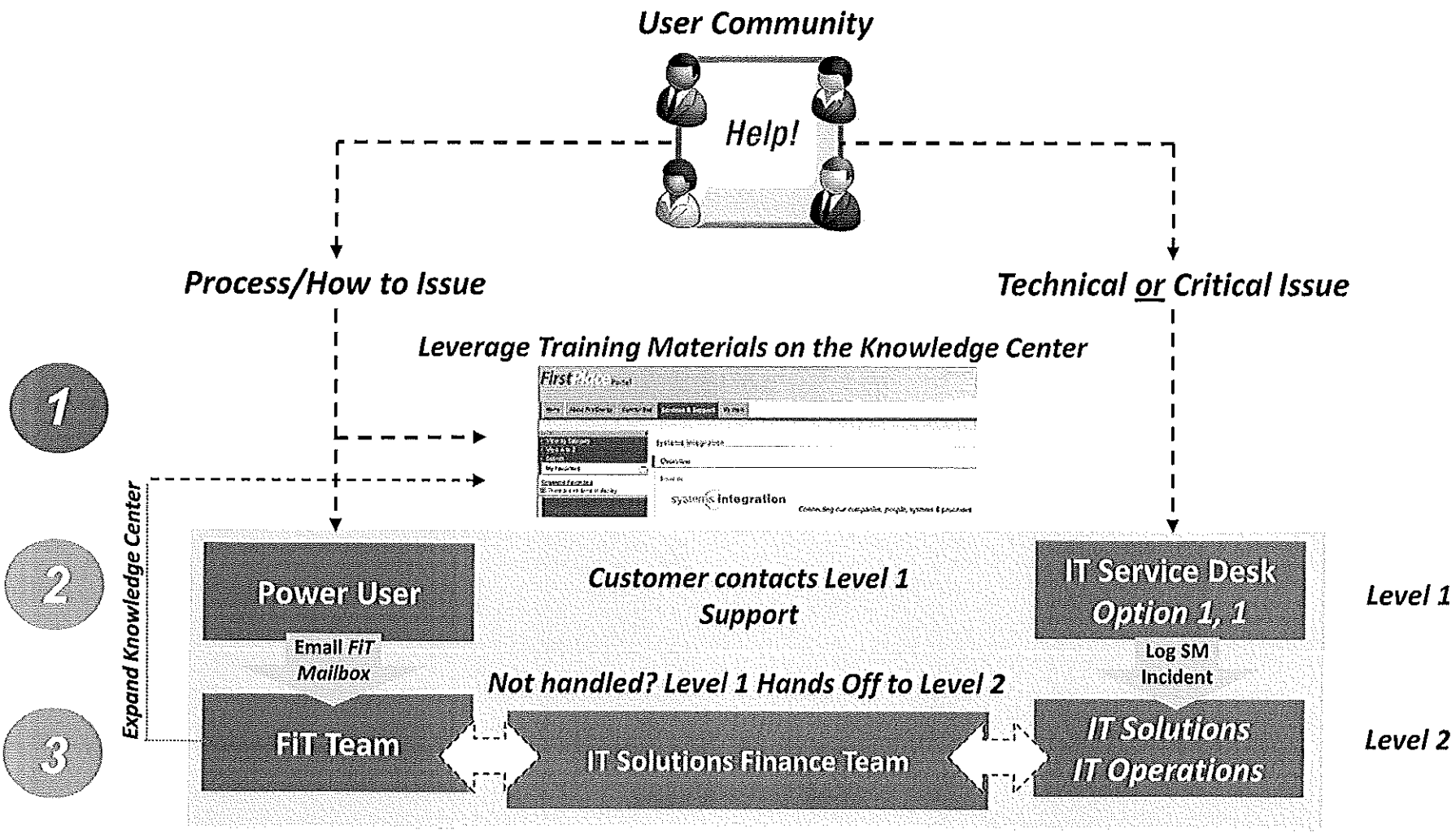
UIPlanner Add In

- **UIPlanner utilizes an Excel Add In function**

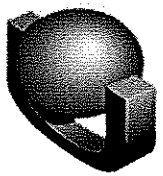
Wrapper

- **An interface that is built to present a calculation to the end user in a more user-friendly fashion**

Where do I go for help?



Thank You for Attending



UTILITIES
International

METROPOLITAN EDISON COMPANY

Original Cost of Plant, Reserves and Accruals by Functions for Fully Projected Future Test Year Ending 4/30/2016

FILING REQUIREMENT V-A-1:

"Provide schedules supporting claimed amounts for Electric Plant in Service by function and by account if available."

FILING REQUIREMENT V-A-2:

"Provide a comparison of calculated depreciation reserve versus book reserve at the end of the test year. Provide this comparison by functional group and by account if available."

FILING REQUIREMENT V-B-1:

"Provide a comparison of calculated depreciation accruals versus book accruals by function and by account if available."

FILING REQUIREMENT V-D-1:

"Provide the surviving original cost plant at the appropriated test year date or dates by account and functional property group and include claimed depreciation reserves. Provide annual depreciation accruals where appropriate. These calculations should be provided for plant in service as well as other categories of plant, including but not limited to, contributions in aid of construction, customers' advances for construction and anticipated retirements associated with construction work in progress claims, if applicable."

RESPONSE:

Met-Ed Exhibit RAD-46 Attachment A satisfies the filing requirements cited above. The accruals shown on Met-Ed Exhibit RAD-46 Attachment A are claimed remaining life accruals for booking.

Met-Ed Exhibit RAD-46 Attachment B provides original cost activity at detail account levels for plant and reserves, updating this information from 4/30/15 through 4/30/16, the fully projected future test year-end. Additionally, this exhibit shows the affected balances after net adjustments made for rate case purposes, and the affected balances after net adjustments. This information is in support of Met-Ed Exhibit RAD-46 Attachment A as follows:

Pages 1-2 Company claim basis for Electric Plant in Service reflecting projected plant at 4/30/16 and net adjustments thereto.

Pages 3-4 Company claim basis of book reserves for Electric Plant in Service at 4/30/16 and net adjustments thereto.

Pages 5 Informational calculated reserves at 4/30/16 for Electric Plant in Service and net adjustments thereto.

Metropolitan Edison Company
Accrual Expense Computation after Adjustments
At Future Year from May 2015 to April 2016

Line No.	Description	Adjusted Plant Balances			Book Depreciation Reserve	Depreciation Reserve Ratio	Net Uncovered Book Plant	Accrual Average Remaining Life Basis		Calculated Reserve	Book Reserve	Difference	Difference as a % of Calculated Reserve
		Non Depreciable	Depreciable	Total				Amount	Effective Rate				
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Transmission	-	-	-	-	0.00%	-	-	0.00%	-	-	-	0.00%
2	Distribution	3,205	2,046,714	2,049,919	623,728	30.43%	1,426,191	38,818	1.90%	507,318	623,728	(116,410)	-22.95%
3	General Plant	2,673	151,689	154,362	96,228	62.34%	58,133	5,994	3.95%	88,711	96,228	(7,518)	-8.47%
4	Subtotal	5,878	2,198,403	2,204,281	719,956	32.66%	1,484,324	44,812	2.04%	596,028	719,956	(123,928)	-20.79%
5	Intangible Plant	289	61,287	61,576	31,345	50.90%	30,231	8,069	13.17%	38,277	31,345	6,932	18.11%
6	Total	6,166	2,259,690	2,265,856	751,301	33.16%	1,514,555	52,881	2.34%	634,306	751,301	(116,996)	-18.44%
	Exhibit Reference	RAD-46 Attachment B P 1-2	RAD-46 Attachment B P 1-2	RAD-46 Attachment B P 1-2	RAD-46 Attachment B P 3-4			RAD-53 Attachment A P 1-2		RAD-46 Attachment B P 5-6	RAD-46 Attachment B P 3-4		

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 4/30/15 to 4/30/16
Plant-In-Service

Acct No	Description	Balance 4/30/15	Budget Activity: Additions	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 4/30/16	Adjustments	Adjusted Balance 4/30/16
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	NONDEPRECIABLE PLANT							
	Intangible Plant							
301	Organization	$ 123,507	$ -	$ -	$ -	$ 123,507	$ -	$ 123,507
302	Franchise And Consents	165,169	-	-	-	165,169	-	165,169
	Total Intangible Plant	$ 288,676	$ -	$ -	$ -	$ 288,676	$ -	$ 288,676
	Land							
350.11	Transmission Substations	$ 1,384,344	$ -	$ -	$ -	$ 1,384,344	$ (1,384,344)	$ -
350.21	Transmission Lines	2,045,027	-	-	-	2,045,027	(2,045,027)	-
360.11	Distribution Substations.	2,777,235	-	-	-	2,777,235	-	2,777,235
360.21	Distribution Lines	427,642	-	-	-	427,642	-	427,642
389.1	General	2,672,808	-	-	-	2,672,808	-	2,672,808
	Total Land	$ 9,307,056	$ -	$ -	$ -	$ 9,307,056	$ (3,429,372)	$ 5,877,684
	TOTAL NON-DEPRECIABLE PLAN	$ 9,595,732	$ -	$ -	$ -	$ 9,595,732	$ (3,429,372)	$ 6,166,360
	INTANGIBLE PLANT							
303	Misc. Intangible Plant	$ 41,619,083	$ 16,259,071	$ -	$ -	$ 57,878,154	$ (9,694,591)	$ 48,183,564
303	Smart Meter Software	2,249,535	10,853,984	-	-	13,103,518	-	13,103,518
	TOTAL INTANGIBLE PLANT	$ 43,868,618	$ 27,113,055	$ -	$ -	$ 70,981,673	$ (9,694,591)	$ 61,287,082
	NUCLEAR PRODUCTION							
	Nuclear Production							
326	Asset Retirement Costs Nuclear	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TOTAL NUCLEAR PRODUCTION	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TRANSMISSION PLANT							
	TRANSMISSION PLANT							
350.12	Easements - Trans. Subs.	$ 173,374	$ -	$ -	$ -	$ 173,374	$ (173,374)	$ -
350.22	Easements - Trans. Lines	26,760,119	-	-	-	26,760,119	(26,760,119)	-
352.1	Structures, Improvements	6,475,002	-	-	-	6,475,002	(6,475,002)	-
352.2	Clearing, Grading Of Land	304,599	-	-	-	304,599	(304,599)	-
353	Station Equipment	194,644,237	17,706,171	(1,770,617)	-	210,579,791	(210,579,791)	-
354	Towers And Fixtures	41,082,524	-	-	-	41,082,524	(41,082,524)	-
355	Poles And Fixtures	46,549,680	-	-	-	46,549,680	(46,549,680)	-
356.1	Overhd Conductr, Devices	94,554,236	5,143,215	(514,322)	-	99,183,130	(99,183,130)	-
356.2	Clearing, Grading of Land	17,682,895	-	-	-	17,682,895	(17,682,895)	-
358	Undergrnd Conductr,Devices	1,191,163	-	-	-	1,191,163	(1,191,163)	-
359	Roads And Trails	746,971	-	-	-	746,971	(746,971)	-
359.1	ARC Transmission	4,666	-	-	-	4,666	(4,666)	-
	TOTAL TRANSMISSION PLANT	$ 430,169,466	$ 22,849,386	$ (2,284,939)	$ -	$ 450,733,913	$ (450,733,913)	$ -
	DISTRIBUTION PLANT							
360.12	Easements - Dist. Subs.	$ 611,470	$ -	$ -	$ -	$ 611,470	$ -	$ 611,470
360.22	Easements - Dist. Lines	28,320,720	-	-	-	28,320,720	-	28,320,720
361.1	Structures, Improvements	12,746,076	-	-	-	12,746,076	-	12,746,076
361.2	Clearing, Grading of Land	366,045	-	-	-	366,045	-	366,045
362	Station Equipment	213,272,785	3,916,600	(391,660)	-	216,797,725	-	216,797,725
364	Poles, Towers And Fixtures	354,210,686	-	-	-	354,210,686	-	354,210,686
365	Overhd Conductr, Devices	368,193,014	-	-	-	368,193,014	-	368,193,014
365.1	Clearing, Grading of Land	131,739,866	-	-	-	131,739,866	-	131,739,866
366	Underground Conduit	30,296,760	-	-	-	30,296,760	-	30,296,760
367	Undergrnd Conductr,Devices	203,212,529	-	-	-	203,212,529	-	203,212,529
368	Line Transformers	453,921,791	53,715,097	(5,371,510)	-	502,265,379	-	502,265,379
369	Services OH	71,066,339	-	-	-	71,066,339	-	71,066,339
369	Unground Services	98,458,792	-	-	-	98,458,792	-	98,458,792
370	Meters	66,794,533	-	-	-	66,794,533	(66,794,533)	-
370	Smart Meters Res	2,470,358	10,166,426	(1,016,643)	-	11,620,142	-	11,620,142
371	Inst. On Cust. Prem.	4,519,593	-	-	-	4,519,593	-	4,519,593
373.1	Street Light - Oh, Ug Lines	12,289,135	-	-	-	12,289,135	-	12,289,135

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 4/30/15 to 4/30/16
Plant-In-Service

Acct No	Description	Balance 4/30/15	Budget Activity Additions	Retirements	Transfers/ Adjustments	Balance 4/30/16	Adjustments	Adjusted Balance 4/30/16
374	ARC Distribution	37,210	-	-	-	37,210	(37,210)	-
	TOTAL DISTRIBUTION PLANT	$ 2,052,527,703	$ 67,798,124	$ (6,779,812)	$ -	$ 2,113,546,014	$ (66,831,743)	$ 2,046,714,271
	GENERAL PLANT							
389.2	Easements	$ 18,078	$ -	$ -	$ -	$ 18,078	$ (3,028)	$ 15,050
390.1	Structures, Improvements	87,468,165	442	(44)	-	87,468,562	(14,650,984)	72,817,578
390.2	Clearing, Grading of Land	12,466,282	-	-	-	12,466,282	(2,088,102)	10,378,180
390.3	Struct Imprv, Leasehold Imp	16,754	-	-	-	16,754	(2,806)	13,948
391.1	Office Furn., Mech. Equip.	16,630,775	-	-	-	16,630,775	(2,785,655)	13,845,120
391.15	Office Machines	5,920,633	-	-	-	5,920,633	(991,706)	4,928,927
391.2	Data Processing Equipment	4,626,945	-	-	-	4,626,945	(775,013)	3,851,932
391.25	Data Proc Smart Meters	6,503,330	3,106,583	(310,658)	-	9,299,254	-	9,299,254
391.25	Information System	(11,738)	-	-	-	(11,738)	1,966	(9,772)
392	Transportation Equipment	4,272,477	1,013,658	(101,366)	-	5,184,769	(868,449)	4,316,320
393	Stores Equipment	1,411,422	-	-	-	1,411,422	(236,413)	1,175,009
394	Tools, Shop, Garage Equip.	11,711,828	-	-	-	11,711,828	(1,961,731)	9,750,097
395	Laboratory Equipment	3,047,684	-	-	-	3,047,684	(510,487)	2,537,197
396	Power Operated Equipment	751,658	-	-	-	751,658	(125,903)	625,755
397	Communication Equipment	34,023,088	-	-	-	34,023,088	(18,032,237)	15,990,851
398	Misc. Equipment	2,586,560	-	-	-	2,586,560	(433,249)	2,153,311
399.1	ARC General Plant	105,951	-	-	-	105,951	(105,951)	-
	TOTAL GENERAL PLANT	$ 191,549,891	$ 4,120,682	$ (412,068)	$ -	$ 195,258,505	$ (43,569,748)	$ 151,688,757
	TOTAL	$ 2,823,032,564	$ 121,881,247	$ (9,476,819)	$ -	$ 2,935,436,992	$ (669,580,522)	$ 2,265,856,470

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 4/30/15 to 4/30/16
Book Reserves

Acct No	Description	Balance 4/30/15	Budget Activity: Accruals	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 4/30/16	Adjustments	Adjusted Balance 4/30/16
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	INTANGIBLE PLANT							
303	Software	$ 32,950,380	$ 2,943,599	$ -	$ -	$ 35,893,979	$ (6,012,241)	$ 29,881,737
303	Smart Meters	138,941	1,324,287	-	-	1,463,228	-	1,463,228
	TOTAL INTANGIBLE PLANT	$ 33,089,321	$ 4,267,886	$ -	$ -	$ 37,357,207	$ (6,012,241)	$ 31,344,965
	TRANSMISSION PLANT							
350.12	Tran Sub Easement	$ 107,583	$ 2,602	$ -	$ -	$ 110,185	$ (110,185)	$ -
350.21	Tran Line Land	7,848	-	-	-	7,848	(7,848)	-
350.22	Tran Line Easement	11,872,776	401,540	-	-	12,274,316	(12,274,316)	-
352	Struct PCA Dist	68,303	2,030	-	-	70,333	(70,333)	-
352	Structures/improve	2,790,137	122,101	-	-	2,912,238	(2,912,238)	-
353	Station Eq PCA Dist	2,227,677	137,587	-	-	2,365,264	(2,365,264)	-
353	Station equipment	56,081,740	3,297,645	(1,770,617)	-	57,608,768	(57,608,768)	-
354	Towers & Fixtures	27,230,294	486,478	-	-	27,716,772	(27,716,772)	-
354	Towers PCA Dist	33,799	453	-	-	34,252	(34,252)	-
355	Poles & Fixtures	18,306,343	656,833	-	-	18,963,176	(18,963,176)	-
355	Poles PCA Dist	394,900	8,518	-	-	403,418	(403,418)	-
356	OH Cond PCA Dist	296,153	6,740	-	-	302,893	(302,893)	-
356	Overhead Conductor	27,640,699	1,240,072	(514,322)	-	28,366,449	(28,366,449)	-
356.1	0 Clearing & R/W	3,094,640	90,356	-	-	3,184,996	(3,184,996)	-
356.1	0 R/W PCA Dist	782,274	146,557	-	-	928,831	(928,831)	-
356.2	0 Veg Clrng-FERC exp	-	-	-	-	-	-	-
358	UG Cond PCA Dist	309	48	-	-	357	(357)	-
358	Undergound Conductor	100,517	29,198	-	-	129,715	(129,715)	-
359	Roads & Trails	526,877	16,548	-	-	543,425	(543,425)	-
359	Roads PCA Dist	7,998	268	-	-	8,266	(8,266)	-
359.1	TXM SUB ARC	2,727	104	-	-	2,831	(2,831)	-
	TOTAL TRANSMISSION PLANT	$ 151,573,594	$ 6,645,678	$ (2,284,939)	$ -	$ 155,934,333	$ (155,934,333)	$ -
	DISTRIBUTION PLANT							
360.12	Dist Sub Easement	$ 182,521	$ 9,004	$ -	$ -	$ 191,525	$ -	$ 191,525
360.22	Dist Line Easement	14,418,605	417,008	-	-	14,835,613	-	14,835,613
361	Structure/Improve	6,252,488	313,866	-	-	6,566,354	-	6,566,354
361.2	Grading Clearing	24,386	9,014	-	-	33,400	-	33,400
362	Station equipment	73,880,311	3,312,439	(391,660)	-	76,801,090	-	76,801,090
364	Poles towers fix	109,277,922	4,769,507	-	-	114,047,429	-	114,047,429
365	Overhead conductor	81,413,698	6,143,661	-	-	87,557,359	-	87,557,359
365.1	Clearing & R/W	19,108,306	2,011,562	-	-	21,119,868	-	21,119,868
366	Underground conduit	11,421,375	529,030	-	-	11,950,405	-	11,950,405
367	Undergrd conductor	72,497,543	5,794,026	-	-	78,291,569	-	78,291,569
368	Line Transformers	128,116,708	10,229,065	(5,371,510)	-	132,974,263	-	132,974,263
369	Services OH	19,854,015	1,638,032	-	-	21,492,047	-	21,492,047
369	Unground Services	48,920,654	2,219,858	-	-	51,140,512	-	51,140,512
370	Meters	14,928,912	2,719,479	(1,016,643)	-	16,631,748	(16,631,748)	-
370	Smart Meters Res	171,958	327,423	-	-	499,381	-	499,381
371	Inst on cust prem	1,988,534	123,663	-	-	2,112,197	-	2,112,197
371	Meter Socket dvc 125	186	8	-	-	194	-	194
371	Meter Socket dvc 126	186	8	-	-	194	-	194
371	Meter Socket dvc 127	377	15	-	-	392	-	392
371	Meter Socket dvc 1PH	315,679	13,242	-	-	328,921	-	328,921
371	Meter Socket dvc 3PH	270	11	-	-	281	-	281
371	Surge Suppression 2	240,849		-	-	240,849	-	240,849
371	Surge Suppression 4	35,859		-	-	35,859	-	35,859
373	Street Lighting	3,187,111	321,122	-	-	3,508,233	-	3,508,233
374	DIST SUB ARC	22,253	759	-	-	23,012	(23,012)	-
	TOTAL DISTRIBUTION PLANT	$ 606,260,706	$ 40,901,802	$ (6,779,813)	$ -	$ 640,382,695	$ (16,654,760)	$ 623,727,935

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 4/30/15 to 4/30/16
Book Reserves

Acct No	Description	Balance 4/30/15	Budget Activity: Accruals	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 4/30/16	Adjustments	Adjusted Balance 4/30/16
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	GENERAL PLANT							
389.2	Land Rights	$ 15,648	$ 407	$ -	$ -	$ 16,055	$ (2,689)	$ 13,365
390.1	Easton Serv Center	4,348,061	312,519	-	-	4,660,580	(780,647)	3,879,933
390.1	Lebanon Serv Ctr	3,322,094	187,671	-	-	3,509,765	(587,886)	2,921,879
390.1	South Bldg Reading	26,359,437	1,131,552	(44)	-	27,490,945	(4,604,733)	22,886,212
390.1	Structures	8,273,270	409,507	-	-	8,682,777	(1,454,365)	7,228,412
390.1	York Serv Center	4,210,591	209,705	-	-	4,420,296	(740,400)	3,679,896
390.2	Corp Hqtrs Reading	1,812,398	90,647	-	-	1,903,045	(318,760)	1,584,285
390.2	Easton Ser Ctr	999,764	116,782	-	-	1,116,546	(187,021)	929,525
390.2	Land/Yard Improvem	3,020,759	169,861	-	-	3,190,620	(534,429)	2,656,191
390.2	Lebanon Ser Ctr	818,850	23,374	-	-	842,224	(141,073)	701,152
390.2	York Ser Ctr	1,193,663	46,769	-	-	1,240,432	(207,772)	1,032,660
390.3	Transfered LH	5,201	838	-	-	6,039	(1,012)	5,028
391.1	Office Furniture	15,450,558	742,483	-	-	16,193,041	(2,712,334)	13,480,707
391.15	Office Machines	5,920,633		-	-	5,920,633	(991,706)	4,928,927
391.2	Personal Computers	3,094,514	788,606	-	-	3,883,120	(650,423)	3,232,698
391.25	Data Proc Smart Me	312,781	1,563,011	(310,658)	-	1,565,134	-	1,565,134
391.25	Information Sys	(7,464)	(4,172)	-	-	(11,636)	1,949	(9,687)
392	Transportation equip	111,732	29,749	-	-	141,481	(23,698)	117,783
392.4	Pole Trailers	488,498	25,554	-	-	514,052	(86,104)	427,948
392.5	Van Trailers	79,848	717	-	-	80,565	(13,495)	67,070
393	Stores Equipment	1,411,421	-	-	-	1,411,421	(236,413)	1,175,008
394	Tools shop garage	7,242,071	514,703	-	-	7,756,774	(1,299,260)	6,457,515
395	Laboratory equip	3,047,684	-	-	-	3,047,684	(510,487)	2,537,197
396	Power operated equip	617,698	4,230	-	-	621,928	(104,173)	517,755
397	Communication Equipt	24,679,661	1,078,092	(101,366)	-	25,656,387	(13,597,885)	12,058,502
398	Miscellaneous equipt	2,572,517	14,043	-	-	2,586,560	(433,249)	2,153,311
399	EASTON BLDG ARC	4,078	145	-	-	4,223	(4,223)	-
399	GEN BLDG ARC	30,951	1,193	-	-	32,144	(32,144)	-
399	LEBANON BLDG ARC	4,185	149	-	-	4,334	(4,334)	-
399	READING SOUTH BLDG ARC	8,235	277	-	-	8,512	(8,512)	-
399	YORK BLDG ARC	2,851	101	-	-	2,952	(2,952)	-
	TOTAL GENERAL PLANT	$ 119,452,188	$ 7,458,513	$ (412,068)	$ -	$ 126,498,633	$ (30,270,230)	$ 96,228,403
	NUCLEAR PRODUCTION							
326	TMI#2 ARC	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TOTAL	$ 1,005,696,963	$ 59,273,879	$ (9,476,820)	$ -	$ 1,055,494,022	$ (304,192,719)	$ 751,301,304

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 4/30/15 to 4/30/16
Calculated Reserves

Acct No	Description	Balance 4/30/15	Budget Activity: Accruals	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 4/30/16	Adjustments	Adjusted Balance 4/30/16
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	INTANGIBLE PLANT							
303	Misc. Intangible Plant	$ 38,046,432	$ 6,397,672	$ -	$ -	$ 44,444,104	$ (7,444,387)	$ 36,999,717
303	Smart Meter Software	180,580	1,096,976	-	-	1,277,556	-	1,277,556
	TOTAL INTANGIBLE PLANT	$ 38,227,012	$ 7,494,648	$ -	$ -	$ 45,721,660	$ (7,444,387)	$ 38,277,273
	TRANSMISSION PLANT							
	TRANSMISSION PLANT							
350.12	Easements - Trans. Subs.	$ 108,319	$ 2,601	$ -	$ -	$ 110,920	$ (110,920)	$ -
350.22	Easements - Trans. Lines	14,566,157	401,402	-	-	14,967,559	(14,967,559)	-
352.1	Structures, Improvements	3,180,215	119,140	-	-	3,299,355	(3,299,355)	-
352.2	Clearing, Grading Of Land	14,893	5,605	-	-	20,498	(20,498)	-
353	Station Equipment	45,213,571	3,403,882	(1,770,617)	-	46,846,836	(46,846,836)	-
354	Towers And Fixtures	22,551,869	476,557	-	-	23,028,426	(23,028,426)	-
355	Poles And Fixtures	15,218,339	679,625	-	-	15,897,964	(15,897,964)	-
356.1	Overhd Conductr, Devices	20,979,020	1,278,667	(514,322)	-	21,743,366	(21,743,366)	-
356.2	Clearing, Grading of Land	3,561,762	217,500	-	-	3,779,262	(3,779,262)	-
358	Undergrnd Conductr,Devices	83,539	29,898	-	-	113,437	(113,437)	-
359	Roads And Trails	562,901	16,807	-	-	579,708	(579,708)	-
359.1	ARC Transmission	2,718	104	-	-	2,822	(2,822)	-
	TOTAL TRANSMISSION PLANT	$ 126,043,303	$ 6,631,788	$ (2,284,939)	$ -	$ 130,390,153	$ (130,390,153)	$ -
	DISTRIBUTION PLANT							
360.12	Easements - Dist. Subs.	$ 181,768	$ 8,989	$ -	$ -	$ 190,757	$ -	$ 190,757
360.22	Easements - Dist. Lines	13,740,757	416,315	-	-	14,157,072	-	14,157,072
361.1	Structures, Improvements	6,247,845	309,730	-	-	6,557,575	-	6,557,575
361.2	Clearing, Grading of Land	729,347	8,895	-	-	738,242	-	738,242
362	Station Equipment	58,968,382	3,354,550	(391,660)	-	61,931,272	-	61,931,272
364	Poles, Towers And Fixtures	68,961,103	4,675,581	-	-	73,636,684	-	73,636,684
365	Overhd Conductr, Devices	59,221,488	6,296,101	-	-	65,517,589	-	65,517,589
365.1	Clearing, Grading of Land	18,347,166	2,002,446	-	-	20,349,612	-	20,349,612
366	Underground Conduit	12,331,468	527,164	-	-	12,858,632	-	12,858,632
367	Undergrnd Conductr,Devices	72,203,108	5,791,557	-	-	77,994,665	-	77,994,665
368	Line Transformers	97,998,268	10,231,203	(5,371,510)	-	102,857,961	-	102,857,961
369	Services	18,112,003	1,620,313	-	-	19,732,316	-	19,732,316
369	Underground Conduit	44,415,793	2,195,631	-	-	46,611,424	-	46,611,424
370	Meters	13,873,924	2,798,691	-	-	16,672,615	(16,672,615)	-
370	Smart Meters Res	107,270	469,918	(1,016,643)	-	(439,454)	-	(439,454)
371	Inst. On Cust. Prem.	1,989,222	144,175	-	-	2,133,397	-	2,133,397
373.1	Street Light - Oh, Ug Lines	2,149,736	340,409	-	-	2,490,145	-	2,490,145
374	ARC Distribution	22,190	759	-	-	22,949	(22,949)	-
	TOTAL DISTRIBUTION PLANT	$ 489,600,838	$ 41,192,427	$ (6,779,812)	$ -	$ 524,013,453	$ (16,695,564)	$ 507,317,889
	GENERAL PLANT							
389.2	Easements	$ 16,016	$ 400	$ -	$ -	$ 16,416	$ (2,750)	$ 13,666
390.1	Structures, Improvements	41,775,165	2,142,975	(44)	-	43,918,096	(7,356,281)	36,561,815
390.2	Clearing, Grading of Land	8,121,433	438,813	-	-	8,560,246	(1,433,841)	7,126,405
390.3	Struct Imprv, Leasehold Imp	4,546	590	-	-	5,136	(860)	4,276
391.1	Office Furn., Mech. Equip.	15,331,662	685,188	-	-	16,016,850	(2,682,822)	13,334,028
391.15	Office Machines	6,304,833	0	-	-	6,304,833	(1,056,060)	5,248,773
391.2	Data Processing Equipment	3,493,767	1,990,974	-	-	3,804,810	(637,306)	3,167,504
391.25	Data Proc Smart Meters	342,157	1,580,258	(310,658)	-	1,611,757	-	1,611,757
391.25	Information System	(4,908)	(1,311)	-	-	(6,438)	(1,078)	(7,516)
392	Transportation Equipment	398,497	225,082	(101,366)	-	522,214	(87,471)	434,743
393	Stores Equipment	1,359,700	12,421	-	-	1,372,121	(229,830)	1,142,291
394	Tools, Shop, Garage Equip.	7,532,669	490,726	-	-	8,023,395	(1,343,919)	6,679,476
395	Laboratory Equipment	2,885,332	30	-	-	2,885,362	(483,298)	2,402,064
396	Power Operated Equipment	353,093	12,929	-	-	366,022	(61,309)	304,713
397	Communication Equipment	17,382,386	1,024,095	-	-	18,406,481	(9,755,435)	8,651,046
398	Misc. Equipment	2,397,415	47,593	-	-	2,445,008	(409,539)	2,035,469
399.1	ARC General Plant	50,147	1,865	-	-	52,012	(52,012)	-
	TOTAL GENERAL PLANT	$ 107,743,912	$ 8,652,628	$ (412,068)	$ -	$ 114,304,322	$ (25,593,811)	$ 88,710,511
	TOTAL	$ 761,615,066	$ 63,971,491	$ (9,476,819)	$ -	$ 814,429,587	$ (180,123,915)	$ 634,305,673

METROPOLITAN EDISON COMPANY

Original Cost of Plant, Reserves and Accruals by Functions for Future Test Year Ending 3/31/2015

FILING REQUIREMENT V-A-1:

"Provide schedules supporting claimed amounts for Electric Plant in Service by function and by account if available."

FILING REQUIREMENT V-A-2:

"Provide a comparison of calculated depreciation reserve versus book reserve at the end of the test year. Provide this comparison by functional group and by account if available."

FILING REQUIREMENT V-B-1:

"Provide a comparison of calculated depreciation accruals versus book accruals by function and by account if available."

FILING REQUIREMENT V-D-1:

"Provide the surviving original cost plant at the appropriated test year date or dates by account and functional property group and include claimed depreciation reserves. Provide annual depreciation accruals where appropriate. These calculations should be provided for plant in service as well as other categories of plant, including but not limited to, contributions in aid of construction, customers' advances for construction and anticipated retirements associated with construction work in progress claims, if applicable."

RESPONSE:

Met-Ed Exhibit RAD-47 Attachment A satisfies the filing requirements cited above. The accruals shown on Met-Ed Exhibit RAD-47 Attachment A are claimed remaining life accruals for booking.

Met-Ed Exhibit RAD-47 Attachment B provides original cost activity at detail account levels for plant and reserves, updating this information from 3/31/14 through 3/31/15, the future test year-end. Additionally, this exhibit shows the affected balances after net adjustments made for rate case purposes, and the affected balances after net adjustments. This information is in support of Met-Ed Exhibit RAD-47 Attachment A as follows:

Pages 1-2 Company claim basis for Electric Plant in Service reflecting projected plant at 3/31/15 and net adjustments thereto.

Pages 3-4 Company claim basis of book reserves for Electric Plant in Service at 3/31/15 and net adjustments thereto.

Pages 5 Informational calculated reserves at 3/31/15 for Electric Plant in Service and net adjustments thereto.

Metropolitan Edison Company
Accrual Expense Computation after Adjustments
At Future Year from April 2014 to March 2015
($000)

Line No.	Description	Adjusted Plant Balances			Book Depreciation Reserve	Depreciation Reserve Ratio	Net Uncovered Book Plant	Accrual Average Remaining Life Basis		Calculated Reserve	Book Reserve	Difference	Difference as a % of Calculated Reserve
		Non Depreciable	Depreciable	Total				Amount	Effective Rate				
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Transmission	0	0	0	0	0.00%	0	0	0.00%	0	0	0	0.00%
2	Distribution	3,205	1,981,543	1,984,747	588,627	29.66%	1,396,120	37,020	1.87%	472,584	588,627	(116,043)	-24.55%
3	General Plant	2,673	147,950	150,623	90,041	59.78%	60,582	5,368	3.63%	81,503	90,041	(8,538)	-10.48%
4	Subtotal	5,878	2,129,492	2,135,370	678,668	31.78%	1,456,702	42,388	1.99%	554,087	678,668	(124,581)	-22.48%
5	Intangible Plant	289	36,794	37,083	27,385	73.85%	9,697	4,763	12.94%	31,428	27,385	4,043	12.86%
6	Total	6,166	2,166,286	2,172,453	706,053	32.50%	1,466,400	47,150	2.18%	585,515	706,053	(120,538)	-20.59%

Exhibit Reference									
	RAD-47 Attachment B P 1-2	RAD-47 Attachment B P 1-2	RAD-47 Attachment B P 1-2	RAD-47 Attachment B P 3-4		RAD-53 Attachment A P 1-2		RAD-47 Attachment B P 5-6	RAD-47 Attachment B P 3-4

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/14 to 3/31/15
Plant-In-Service

Acct No	Description	Balance 3/31/14	Budget Activity: Additions	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 3/31/15	Adjustments	Adjusted Balance 3/31/15
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	NONDEPRECIABLE PLANT							
	Intangible Plant							
301	Organization	$ 123,507	$ -	$ -	$ -	$ 123,507	$ -	$ 123,507
302	Franchise And Consents	165,169	-	-	-	165,169	-	165,169
	Total Intangible Plant	$ 288,676	$ -	$ -	$ -	$ 288,676	$ -	$ 288,676
	Land							
350.11	Transmission Substations	$ 1,384,344	$ -	$ -	$ -	$ 1,384,344	$ (1,384,344)	$ -
350.21	Transmission Lines	2,045,027	-	-	-	2,045,027	(2,045,027)	-
360.11	Distribution Substations.	2,777,235	-	-	-	2,777,235	-	2,777,235
360.21	Distribution Lines	427,642	-	-	-	427,642	-	427,642
389.1	General	2,672,808	-	-	-	2,672,808	-	2,672,808
	Total Land	$ 9,307,056	$ -	$ -	$ -	$ 9,307,056	$ (3,429,372)	$ 5,877,684
	TOTAL NON-DEPRECIABLE PLANT	$ 9,595,732	$ -	$ -	$ -	$ 9,595,732	$ (3,429,372)	$ 6,166,360
	INTANGIBLE PLANT							
303	Misc. Intangible Plant	$ 38,675,265	$ 2,927,401	$ -	$ -	$ 41,602,665	$ (6,968,446)	$ 34,634,219
303	Smart Meter Software	-	2,159,907	-	-	2,159,907	-	2,159,907
	TOTAL INTANGIBLE PLANT	$ 38,675,265	$ 5,087,308	$ -	$ -	$ 43,762,573	$ (6,968,446)	$ 36,794,126
	NUCLEAR PRODUCTION							
	Nuclear Production							
326	Asset Retirement Costs Nuclear	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TOTAL NUCLEAR PRODUCTION	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TRANSMISSION PLANT							
	TRANSMISSION PLANT							
350.12	Easements - Trans. Subs.	$ 173,374	$ -	$ -	$ -	$ 173,374	$ (173,374)	$ -
350.22	Easements - Trans. Lines	26,760,119	-	-	-	26,760,119	(26,760,119)	-
352.1	Structures, Improvements	6,475,002	-	-	-	6,475,002	(6,475,002)	-
352.2	Clearing, Grading Of Land	304,599	-	-	-	304,599	(304,599)	-
353	Station Equipment	183,422,634	12,419,729	(1,241,973)	-	194,600,390	(194,600,390)	-
354	Towers And Fixtures	41,082,524	-	-	-	41,082,524	(41,082,524)	-
355	Poles And Fixtures	46,549,680	-	-	-	46,549,680	(46,549,680)	-
356.1	Overhd Conductr, Devices	69,632,543	27,306,538	(2,730,654)	-	94,208,427	(94,208,427)	-
356.2	Clearing, Grading of Land	17,682,895	-	-	-	17,682,895	(17,682,895)	-
358	Undergrnd Conductr,Devices	1,191,163	-	-	-	1,191,163	(1,191,163)	-
359	Roads And Trails	746,971	-	-	-	746,971	(746,971)	-
359.1	ARC Transmission	4,666	-	-	-	4,666	(4,666)	-
	TOTAL TRANSMISSION PLANT	$ 394,026,169	$ 39,726,267	$ (3,972,627)	$ -	$ 429,779,809	$ (429,779,809)	$ -
	DISTRIBUTION PLANT							
360.12	Easements - Dist. Subs.	$ 611,470	$ -	$ -	$ -	$ 611,470	$ -	$ 611,470
360.22	Easements - Dist. Lines	28,320,720	-	-	-	28,320,720	-	28,320,720
361.1	Structures, Improvements	12,746,076	-	-	-	12,746,076	-	12,746,076
361.2	Clearing, Grading of Land	366,045	-	-	-	366,045	-	366,045
362	Station Equipment	203,494,152	10,531,662	(1,053,166)	-	212,972,648	-	212,972,648
364	Poles, Towers And Fixtures	354,210,686	-	-	-	354,210,686	-	354,210,686
365	Overhd Conductr, Devices	368,193,014	-	-	-	368,193,014	-	368,193,014
365.1	Clearing, Grading of Land	131,739,866	-	-	-	131,739,866	-	131,739,866
366	Underground Conduit	30,296,760	-	-	-	30,296,760	-	30,296,760
367	Undergrnd Conductr,Devices	203,212,529	-	-	-	203,212,529	-	203,212,529
368	Line Transformers	392,737,933	63,955,159	(6,395,516)	-	450,297,576	-	450,297,576
369	Services OH	71,066,339	-	-	-	71,066,339	-	71,066,339
369	Unground Services	98,458,792	-	-	-	98,458,792	-	98,458,792
370	Meters	66,794,533	-	-	-	66,794,533	(66,794,533)	0
370	Smart Meters Res	1,554,367	763,326	(76,333)	-	2,241,360	-	2,241,360
371	Inst. On Cust. Prem.	4,519,593	-	-	-	4,519,593	-	4,519,593
373.1	Street Light - Oh, Ug Lines	12,289,135	-	-	-	12,289,135	-	12,289,135
374	ARC Distribution	37,210	-	-	-	37,210	(37,210)	0
	TOTAL DISTRIBUTION PLANT	$ 1,980,649,220	$ 75,250,147	$ (7,525,015)	$ -	$ 2,048,374,353	$ (66,831,743)	$ 1,981,542,609

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/14 to 3/31/15
Plant-In-Service

Acct No	Description	Balance 3/31/14	Budget Activity			Balance 3/31/15	Adjustments	Adjusted Balance 3/31/15
			Additions	Retirements	Transfers/ Adjustments			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	GENERAL PLANT							
389.2	Easements	$ 18,078	$ -	$ -	$ -	$ 18,078	$ (3,028)	$ 15,050
390.1	Structures, Improvements	85,738,057	1,922,342	(192,234)	-	87,468,165	(14,650,918)	72,817,247
390.2	Clearing, Grading of Land	12,466,282	-	-	-	12,466,282	(2,088,102)	10,378,180
390.3	Struct Imprv, Leasehold Imp	16,754	-	-	-	16,754	(2,806)	13,948
391.1	Office Furn., Mech. Equip.	16,630,775	-	-	-	16,630,775	(2,785,655)	13,845,120
391.15	Office Machines	5,920,633	-	-	-	5,920,633	(991,706)	4,928,927
391.2	Data Processing Equipment	4,626,945	-	-	-	4,626,945	(775,013)	3,851,932
391.25	Data Proc Smart Meters	902,575	6,059,138	(605,914)	-	6,355,799	-	6,355,799
391.25	Information System	(11,738)	-	-	-	(11,738)	1,966	(9,772)
392	Transportation Equipment	1,066,971	3,513,906	(351,391)	-	4,229,487	(708,439)	3,521,048
393	Stores Equipment	1,411,422	-	-	-	1,411,422	(236,413)	1,175,009
394	Tools, Shop, Garage Equip.	11,711,828	-	-	-	11,711,828	(1,961,731)	9,750,097
395	Laboratory Equipment	3,047,684	-	-	-	3,047,684	(510,487)	2,537,197
396	Power Operated Equipment	751,658	-	-	-	751,658	(125,903)	625,755
397	Communication Equipment	34,023,088	-	-	-	34,023,088	(18,032,237)	15,990,851
398	Misc. Equipment	2,586,560	-	-	-	2,586,560	(433,249)	2,153,311
399.1	ARC General Plant	105,951	-	-	-	105,951	(105,951)	0
	TOTAL GENERAL PLANT	$ 181,013,523	$ 11,495,386	$ (1,149,539)	$ -	$ 191,359,370	$ (43,409,672)	$ 147,949,698
	TOTAL	$ 2,699,281,063	$ 131,559,108	$ (12,647,180)	$ -	$ 2,818,192,991	$ (645,740,197)	$ 2,172,452,794

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/14 to 3/31/15
Book Reserves

Acct No	Description	Balance 3/31/14	Budget Activity: Accruals	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 3/31/15	Adjustments	Adjusted Balance 3/31/15
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	INTANGIBLE PLANT							
303	Software	$ 30,402,371	$ 2,366,058	$ -	$ -	$ 32,768,429	$ (5,488,712)	$ 27,279,717
303	Smart Meters	-	105,622	-	-	105,622	-	105,622
	TOTAL INTANGIBLE PLANT	$ 30,402,371	$ 2,471,680	$ -	$ -	$ 32,874,051	$ (5,488,712)	$ 27,385,339
	TRANSMISSION PLANT							
350.12	Tran Sub Easement	$ 104,764	$ 2,602	$ -	$ -	$ 107,366	$ (107,366)	$ -
350.21	Tran Line Land	7,848	-	-	-	7,848	(7,848)	-
350.22	Tran Line Easement	11,437,774	401,540	-	-	11,839,314	(11,839,314)	-
352	Struct PCA Dist	66,104	2,030	-	-	68,134	(68,134)	-
352	Structures/improve	2,657,861	122,101	-	-	2,779,962	(2,779,962)	-
353	Station Eq PCA Dist	2,078,624	137,587	-	-	2,216,211	(2,216,211)	-
353	Station equipment	54,044,683	3,026,853	(1,241,973)	-	55,829,563	(55,829,563)	-
354	Towers & Fixtures	26,703,276	486,478	-	-	27,189,754	(27,189,754)	-
354	Towers PCA Dist	33,308	453	-	-	33,761	(33,761)	-
355	Poles & Fixtures	17,594,774	656,833	-	-	18,251,607	(18,251,607)	-
355	Poles PCA Dist	385,672	8,518	-	-	394,190	(394,190)	-
356	OH Cond PCA Dist	288,851	6,740	-	-	295,591	(295,591)	-
356	Overhead Conductor	29,183,652	1,125,540	(2,730,654)	-	27,578,538	(27,578,538)	-
356.1	0 Clearing & R/W	2,996,754	90,356	-	-	3,087,110	(3,087,110)	-
356.1	0 R/W PCA Dist	623,504	146,557	-	-	770,061	(770,061)	-
356.2	0 Veg Clrng-FERC exp	-	-	-	-	-	-	-
358	UG Cond PCA Dist	257	48	-	-	305	(305)	-
358	Undergound Conductor	68,886	29,198	-	-	98,084	(98,084)	-
359	Roads & Trails	508,950	16,548	-	-	525,498	(525,498)	-
359	Roads PCA Dist	7,708	268	-	-	7,976	(7,976)	-
359.1	TXM SUB ARC	2,614	104	-	-	2,718	(2,718)	-
	TOTAL TRANSMISSION PLANT	$ 148,795,864	$ 6,260,354	$ (3,972,627)	$ -	$ 151,083,591	$ (151,083,591)	$ -
	DISTRIBUTION PLANT							
360.12	Dist Sub Easement	$ 172,767	$ 9,004	$ -	$ -	$ 181,771	$ -	$ 181,771
360.22	Dist Line Easement	13,966,846	417,008	-	-	14,383,854	-	14,383,854
361	Structure/Improve	5,912,467	313,866	-	-	6,226,333	-	6,226,333
361.2	Grading Clearing	14,621	9,014	-	-	23,635	-	23,635
362	Station equipment	71,463,977	3,228,717	(1,053,166)	-	73,639,528	-	73,639,528
364	Poles towers fix	104,110,956	4,769,507	-	-	108,880,463	-	108,880,463
365	Overhead conductor	74,758,065	6,143,661	-	-	80,901,726	-	80,901,726
365.1	Clearing & R/W	16,929,114	2,011,562	-	-	18,940,676	-	18,940,676
366	Underground conduit	10,848,259	529,030	-	-	11,377,289	-	11,377,289
367	Undergrd conductor	66,220,681	5,794,026	-	-	72,014,707	-	72,014,707
368	Line Transformers	124,984,867	9,124,863	(6,395,516)	-	127,714,214	-	127,714,214
369	Services OH	18,079,480	1,638,032	-	-	19,717,512	-	19,717,512
369	Unground Services	46,515,808	2,219,858	-	-	48,735,666	-	48,735,666
370	Meters	12,084,587	2,719,479	(76,333)	-	14,727,733	(14,727,733)	-
370	Smart Meters Res	49,520	109,350	-	-	158,870	-	158,870
371	Inst on cust prem	1,854,566	123,663	-	-	1,978,229	-	1,978,229
371	Meter Socket dvc 125	177	8	-	-	185	-	185
371	Meter Socket dvc 126	177	8	-	-	185	-	185
371	Meter Socket dvc 127	361	15	-	-	376	-	376
371	Meter Socket dvc 1PH	301,334	13,242	-	-	314,576	-	314,576
371	Meter Socket dvc 3PH	258	11	-	-	269	-	269
371	Surge Suppression 2	240,849	-	-	-	240,849	-	240,849
371	Surge Suppression 4	35,859	-	-	-	35,859	-	35,859
373	Street Lighting	2,839,229	321,122	-	-	3,160,351	-	3,160,351
374	DIST SUB ARC	21,431	759	-	-	22,190	(22,190)	-
	TOTAL DISTRIBUTION PLANT	$ 571,406,256	$ 39,495,805	$ (7,525,015)	$ -	$ 603,377,046	$ (14,749,923)	$ 588,627,123

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/14 to 3/31/15
Book Reserves

Acct No	Description	Balance 3/31/14	Budget Activity			Balance 3/31/15	Adjustments	Adjusted Balance 3/31/15
			Accruals	Retirements	Transfers/ Adjustments			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	GENERAL PLANT							
389.2	Land Rights	$ 15,207	$ 407	$ -	$ -	$ 15,614	$ (2,615)	$ 12,998
390.1	Easton Serv Center	4,009,499	312,519	-	-	4,322,018	(723,938)	3,598,080
390.1	Lebanon Serv Ctr	3,118,784	187,671	-	-	3,306,455	(553,831)	2,752,624
390.1	South Bldg Reading	25,342,274	1,115,101	(192,234)	-	26,265,141	(4,399,411)	21,865,730
390.1	Structures	7,829,637	409,507	-	-	8,239,144	(1,380,057)	6,859,087
390.1	York Serv Center	3,983,411	209,705	-	-	4,193,116	(702,347)	3,490,769
390.2	Corp Hqtrs Reading	1,714,197	90,647	-	-	1,804,844	(302,311)	1,502,533
390.2	Easton Ser Ctr	873,250	116,782	-	-	990,032	(165,830)	824,202
390.2	Land/Yard Improvem	2,836,743	169,861	-	-	3,006,604	(503,606)	2,502,997
390.2	Lebanon Ser Ctr	793,528	23,374	-	-	816,902	(136,831)	680,071
390.2	York Ser Ctr	1,142,997	46,769	-	-	1,189,766	(199,286)	990,481
390.3	Transfered LH	4,293	838	-	-	5,131	(859)	4,272
391.1	Office Furniture	14,646,201	742,483	-	-	15,388,684	(2,577,605)	12,811,079
391.15	Office Machines	5,920,633	-	-	-	5,920,633	(991,706)	4,928,927
391.2	Personal Computers	2,240,191	788,606	-	-	3,028,797	(507,324)	2,521,474
391.25	Data Proc Smart Me	86,074	741,854	(605,914)	-	222,014	-	222,014
391.25	Information Sys	(2,944)	(4,172)	-	-	(7,116)	1,192	(5,924)
392	Transportation equip	79,504	29,749	-	-	109,253	(18,300)	90,953
392.4	Pole Trailers	460,815	25,554	-	-	486,369	(81,467)	404,902
392.5	Van Trailers	79,071	717	-	-	79,788	(13,364)	66,423
393	Stores Equipment	1,404,210	7,211	-	-	1,411,421	(236,413)	1,175,008
394	Tools shop garage	6,684,476	514,703	-	-	7,199,179	(1,205,863)	5,993,317
395	Laboratory equip	3,047,684	-	-	-	3,047,684	(510,487)	2,537,197
396	Power operated equip	613,115	4,230	-	-	617,345	(103,405)	513,940
397	Communication Equipt	23,913,531	1,033,712	(351,391)	-	24,595,852	(13,035,802)	11,560,051
398	Miscellaneous equipt	2,505,460	61,899	-	-	2,567,359	(430,033)	2,137,326
399	EASTON BLDG ARC	3,921	145	-	-	4,066	(4,066)	-
399	GEN BLDG ARC	29,659	1,193	-	-	30,852	(30,852)	-
399	LEBANON BLDG ARC	4,024	149	-	-	4,173	(4,173)	-
399	READING SOUTH BLDG ARC	7,935	277	-	-	8,212	(8,212)	-
399	YORK BLDG ARC	2,742	101	-	-	2,843	(2,843)	-
	TOTAL GENERAL PLANT	$ 113,390,122	$ 6,631,592	$ (1,149,539)	$ -	$ 118,872,175	$ (28,831,646)	$ 90,040,529
	NUCLEAR PRODUCTION							
326	TMI#2 ARC	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TOTAL	$ 959,315,767	$ 54,859,431	$ (12,647,181)	$ -	$ 1,001,528,017	$ (295,475,026)	$ 706,052,991

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/14 to 3/31/15
Calculated Reserves

Acct No	Description	Balance 3/31/14	Budget Activity: Accruals	Budget Activity: Retirements	Budget Activity: Transfers/ Adjustments	Balance 3/31/15	Adjustments	Adjusted Balance 3/31/15
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	INTANGIBLE PLANT							
303	Misc. Intangible Plant	$ 32,404,302	$ 5,161,871	$ -	$ -	$ 37,566,173	$ (6,292,334)	$ 31,273,839
303	Smart Meter Software	-	154,325	-	-	154,325	-	154,325
	TOTAL INTANGIBLE PLANT	$ 32,404,302	$ 5,316,196	$ -	$ -	$ 37,720,498	$ (6,292,334)	$ 31,428,164
	TRANSMISSION PLANT							
	TRANSMISSION PLANT							
350.12	Easements - Trans. Subs.	$ 105,501	$ 2,601	$ -	$ -	$ 108,102	$ (108,102)	$ -
350.22	Easements - Trans. Lines	14,131,305	401,402	-	-	14,532,707	(14,532,707)	0
352.1	Structures, Improvements	3,051,201	119,140	-	-	3,170,341	(3,170,341)	0
352.2	Clearing, Grading Of Land	8,823	5,605	-	-	14,428	(14,428)	0
353	Station Equipment	43,010,923	3,175,393	(1,241,973)	-	44,944,343	(44,944,343)	0
354	Towers And Fixtures	22,034,572	476,557	-	-	22,511,129	(22,511,129)	0
355	Poles And Fixtures	14,483,242	679,625	-	-	15,162,867	(15,162,867)	0
356.1	Overhd Conductr, Devices	22,526,864	1,081,350	(2,730,654)	-	20,877,560	(20,877,560)	0
356.2	Clearing, Grading of Land	3,326,137	217,500	-	-	3,543,637	(3,543,637)	0
358	Undergrnd Conductr,Devices	51,199	29,898	-	-	81,097	(81,097)	0
359	Roads And Trails	544,693	16,807	-	-	561,500	(561,500)	0
359.1	ARC Transmission	2,614	104	-	-	2,718	(2,718)	0
	TOTAL TRANSMISSION PLANT	$ 123,277,074	$ 6,205,982	$ (3,972,627)	$ -	$ 125,510,429	$(125,510,429)	$ -
	DISTRIBUTION PLANT							
360.12	Easements - Dist. Subs.	$ 172,030	$ 8,989	$ -	$ -	$ 181,019	$ -	$ 181,019
360.22	Easements - Dist. Lines	13,289,749	416,315	-	-	13,706,064	-	13,706,064
361.1	Structures, Improvements	5,911,986	309,730	-	-	6,221,716	-	6,221,716
361.2	Clearing, Grading of Land	719,702	8,895	-	-	728,597	-	728,597
362	Station Equipment	56,499,600	3,248,441	(1,053,166)	-	58,694,875	-	58,694,875
364	Poles, Towers And Fixtures	63,887,035	4,675,581	-	-	68,562,616	-	68,562,616
365	Overhd Conductr, Devices	52,412,985	6,296,101	-	-	58,709,086	-	58,709,086
365.1	Clearing, Grading of Land	16,176,752	2,002,446	-	-	18,179,198	-	18,179,198
366	Underground Conduit	11,760,121	527,164	-	-	12,287,285	-	12,287,285
367	Undergrnd Conductr,Devices	65,928,921	5,791,557	-	-	71,720,478	-	71,720,478
368	Line Transformers	94,567,042	9,020,480	(6,395,516)	-	97,192,006	-	97,192,006
369	Services	16,355,480	1,620,313	-	-	17,975,793	-	17,975,793
369	Underground Conduit	42,035,552	2,195,631	-	-	44,231,183	-	44,231,183
370	Meters	10,848,688	2,798,691	-	-	13,647,379	(13,647,379)	0
370	Smart Meters Res	43,921	126,587	(76,333)	-	94,175	-	94,175
371	Inst. On Cust. Prem.	1,832,882	144,175	-	-	1,977,057	-	1,977,057
373.1	Street Light - Oh, Ug Lines	1,782,598	340,409	-	-	2,123,007	-	2,123,007
374	ARC Distribution	21,431	759	-	-	22,190	(22,190)	0
	TOTAL DISTRIBUTION PLANT	$ 454,246,475	$39,532,264	$ (7,525,015)	$ -	$ 486,253,724	$ (13,669,569)	$ 472,584,156
	GENERAL PLANT							
389.2	Easements	$ 15,582	$ 400	$ -	$ -	$ 15,982	$ (2,677)	$ 13,305
390.1	Structures, Improvements	39,644,446	2,121,776	(192,234)	-	41,573,988	(6,963,643)	34,610,345
390.2	Clearing, Grading of Land	7,653,948	438,813	-	-	8,092,761	(1,355,537)	6,737,224
390.3	Struct Imprv, Leasehold Imp	3,917	590	-	-	4,507	(755)	3,752
391.1	Office Furn., Mech. Equip.	14,563,459	685,188	-	-	15,248,647	(2,554,148)	12,694,499
391.15	Office Machines	6,275,279	-	-	-	6,275,279	(1,051,109)	5,224,170
391.2	Data Processing Equipment	1,479,697	1,990,974	-	-	1,790,740	(299,949)	1,490,791
391.25	Data Proc Smart Meters	115,075	725,837	(605,914)	-	234,998	-	234,998
391.25	Information System	(3,538)	(1,311)	-	-	(5,068)	849	(4,219)
392	Transportation Equipment	602,648	126,056	(351,391)	-	377,313	(63,200)	314,113
393	Stores Equipment	1,344,727	12,421	-	-	1,357,148	(227,322)	1,129,826
394	Tools, Shop, Garage Equip.	6,999,097	490,726	-	-	7,489,823	(1,254,545)	6,235,278
395	Laboratory Equipment	2,885,251	30	-	-	2,885,281	(483,285)	2,401,997
396	Power Operated Equipment	339,813	12,929	-	-	352,742	(59,084)	293,658
397	Communication Equipment	16,277,203	1,024,095	-	-	17,301,298	(9,169,688)	8,131,610
398	Misc. Equipment	2,344,670	47,593	-	-	2,392,263	(400,704)	1,991,559
399.1	ARC General Plant	48,282	1,865	-	-	50,147	(50,147)	0
	TOTAL GENERAL PLANT	$ 100,589,557	$ 7,677,982	$ (1,149,539)	$ -	$ 105,437,851	$ (23,934,946)	$ 81,502,905
	TOTAL	$ 710,517,409	$58,732,424	$ (12,647,180)	$ -	$ 754,922,503	$(169,407,278)	$ 585,515,225

METROPOLITAN EDISON COMPANY

Original Cost of Plant, Reserves and Accruals by Functions for Historical Test Year Ended 3/31/2014

FILING REQUIREMENT V-A-1:

"Provide schedules supporting claimed amounts for Electric Plant in Service by function and by account if available."

FILING REQUIREMENT V-A-2:

"Provide a comparison of calculated depreciation reserve versus book reserve at the end of the test year. Provide this comparison by functional group and by account if available."

FILING REQUIREMENT V-B-1:

"Provide a comparison of calculated depreciation accruals versus book accruals by function and by account if available."

FILING REQUIREMENT V-D-1:

"Provide the surviving original cost plant at the appropriated test year date or dates by account and functional property group and include claimed depreciation reserves. Provide annual depreciation accruals where appropriate. These calculations should be provided for plant in service as well as other categories of plant, including but not limited to, contributions in aid of construction, customers' advances for construction and anticipated retirements associated with construction work in progress claims, if applicable."

RESPONSE:

Met-Ed Exhibit RAD-48 Attachment A satisfies the filing requirements cited above. The accruals shown on Met-Ed Exhibit RAD-48 Attachment A are claimed remaining life accruals for booking.

Met-Ed Exhibit RAD-48 Attachment B provides original cost activity at detail account levels for plant and reserves, updating this information from 3/31/13 through 3/31/14, the historical test year-end. Additionally, this exhibit shows the affected balances after net adjustments made for rate case purposes, and the affected balances after net adjustments. This information is in support of Met-Ed Exhibit RAD-48 Attachment A as follows:

Pages 1-2 Company claim basis for Electric Plant in Service reflecting projected plant at 3/31/14 and net adjustments thereto.

Pages 3-4 Company claim basis of book reserves for Electric Plant in Service at 3/31/14 and net adjustments thereto.

Pages 5 Informational calculated reserves at 3/31/14 for Electric Plant in Service and net adjustments thereto.

Metropolitan Edison Company
Accrual Expense Computation after Adjustments
At Future Year from April 2013 to March 2014
($000)

Met-Ed Exhibit RAD-48
Witness: R. A. D'Angelo
Attachment A
Page 1 of 1

Line No.	Description	Adjusted Plant Balances			Book Depreciation Reserve	Depreciation Reserve Ratio	Net Uncovered Book Plant	Accrual Average Remaining Life Basis		Calculated Reserve	Book Reserve	Difference	Difference as a % of Calculated Reserve
		Non Depreciable	Depreciable	Total				Amount	Effective Rate				
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Transmission	-	-	-	-	0.00%	-	-	0.00%	-	-	-	0.00%
2	Distribution	3,205	1,913,817	1,917,022	559,300	29.18%	1,357,722	35,549	1.86%	443,376,357	559,300	442,817,056	99.87%
3	General Plant	2,673	138,423	141,096	85,703	60.74%	55,393	4,812	3.48%	77,819,400	85,703	77,733,698	99.89%
4	Subtotal	5,878	2,052,241	2,058,119	645,003	31.34%	1,413,115	40,361	1.97%	521,195,757	645,003	520,550,754	99.88%
5	Intangible Plant	289	32,197	32,486	25,310	77.91%	7,176	4,459	13.85%	26,976,581	25,310	26,951,271	99.91%
6	Total	6,166	2,084,438	2,090,604	670,313	32.06%	1,420,291	44,820	2.15%	548,172,338	670,313	547,502,025	99.88%

Exhibit Reference									
	RAD-48 Attachment B P 1-2	RAD-48 Attachment B P 1-2	RAD-48 Attachment B P 1-2	RAD-48 Attachment B P 3-4		RAD-53 Attachment A P 1-2		RAD-48 Attachment B P 5-6	RAD-48 Attachment B P 3-4

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/13 to 3/31/14
Plant-In-Service

Acct No	Description	Balance 3/31/13	Actual Activity: Additions	Actual Activity: Retirements	Actual Activity: Transfers/ Adjustments	Balance 3/31/14	Adjustments	Adjusted Balance 3/31/14
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	NONDEPRECIABLE PLANT							
	Intangible Plant							
301	Organization	$ 123,507	$ -	$ -	$ -	$ 123,507	$ -	$ 123,507
302	Franchise And Consents	165,169	-	-	-	165,169	-	165,169
	Total Intangible Plant	$ 288,676	$ -	$ -	$ -	$ 288,676	$ -	$ 288,676
	Land							
350.11	Transmission Substations	$ 1,384,344	$ -	$ -	$ -	$ 1,384,344	$ (1,384,344)	$ -
350.21	Transmission Lines	2,045,027	-	-	-	2,045,027	(2,045,027)	-
360.11	Distribution Substations.	2,777,235	-	-	-	2,777,235	-	2,777,235
360.21	Distribution Lines	303,117	124,525	-	-	427,642	-	427,642
389.1	General	1,567,850	1,104,958	-	-	2,672,808	-	2,672,808
	Total Land	$ 8,077,573	$ 1,229,483	$ -	$ -	$ 9,307,056	$ (3,429,372)	$ 5,877,684
	TOTAL NON-DEPRECIABLE PLANT	$ 8,366,250	$ 1,229,483	$ -	$ -	$ 9,595,732	$ (3,429,372)	$ 6,166,360
	INTANGIBLE PLANT							
303	Misc. Intangible Plant	$ 38,319,710	$ 355,554	$ -	$ -	$ 38,675,265	$ (6,478,107)	$ 32,197,158
303	Smart Meter Software	-	-	-	-	-	-	-
	TOTAL INTANGIBLE PLANT	$ 38,319,710	$ 355,554	$ -	$ -	$ 38,675,265	$ (6,478,107)	$ 32,197,158
	NUCLEAR PRODUCTION							
	Nuclear Production							
326	Asset Retirement Costs Nuclear	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TOTAL NUCLEAR PRODUCTION	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
	TRANSMISSION PLANT							
	TRANSMISSION PLANT							
350.12	Easements - Trans. Subs.	$ 409,521	$ (236,147)	$ -	$ -	$ 173,374	$ (173,374)	$ -
350.22	Easements - Trans. Lines	26,760,119	-	-	-	26,760,119	(26,760,119)	-
352.1	Structures, Improvements	5,744,218	730,784	-	-	6,475,002	(6,475,002)	-
352.2	Clearing, Grading Of Land	1,704,204	(355,113)	-	(1,044,491)	304,599	(304,599)	-
353	Station Equipment	166,315,953	17,922,447	(1,022,430)	206,664	183,422,634	(183,422,634)	-
354	Towers And Fixtures	41,961,853	(835,615)	(43,714)	-	41,082,524	(41,082,524)	-
355	Poles And Fixtures	43,899,431	3,155,306	(505,057)	-	46,549,680	(46,549,680)	-
356.1	Overhd Conductr, Devices	64,881,925	5,301,147	(550,529)	-	69,632,543	(69,632,543)	-
356.2	Clearing, Grading of Land	13,185,234	4,760,033	-	(262,373)	17,682,895	(17,682,895)	-
358	Undergrnd Conductr,Devices	1,023,580	167,583	-	-	1,191,163	(1,191,163)	-
359	Roads And Trails	746,971	-	-	-	746,971	(746,971)	-
359.1	ARC Transmission	4,666	-	-	-	4,666	(4,666)	-
	TOTAL TRANSMISSION PLANT	$ 366,637,674	$ 30,610,425	$ (2,121,730)	$ (1,100,200)	$ 394,026,169	$ (394,026,169)	$ -
	DISTRIBUTION PLANT							
360.12	Easements - Dist. Subs.	$ 375,323	$ 236,147	$ -	$ -	$ 611,470	$ -	$ 611,470
360.22	Easements - Dist. Lines	28,320,720	-	-	-	28,320,720	-	28,320,720
361.1	Structures, Improvements	12,675,915	72,483	(2,322)	-	12,746,076	-	12,746,076
361.2	Clearing, Grading of Land	130,317	235,728	-	-	366,045	-	366,045
362	Station Equipment	198,607,004	5,516,100	(1,401,555)	772,603	203,494,152	-	203,494,152
364	Poles, Towers And Fixtures	382,640,929	(26,431,291)	(1,998,952)	-	354,210,686	-	354,210,686
365	Overhd Conductr, Devices	325,681,473	48,060,041	(5,548,499)	-	368,193,014	-	368,193,014
365.1	Clearing, Grading of Land	122,275,939	9,812,851	-	(348,923)	131,739,866	-	131,739,866
366	Underground Conduit	30,228,744	75,426	(7,411)	-	30,296,760	-	30,296,760
367	Undergrnd Conductr,Devices	190,569,314	14,192,343	(1,549,128)	-	203,212,529	-	203,212,529
368	Line Transformers	388,639,778	8,031,488	(3,933,333)	-	392,737,933	-	392,737,933
369	Services OH	68,503,817	2,624,523	(62,001)	-	71,066,339	-	71,066,339
369	Unground Services	98,458,792	-	-	-	98,458,792	-	98,458,792
370	Meters	64,399,297	3,792,170	(1,453,354)	56,420	66,794,533	(66,794,533)	-
370	Smart Meters Res	-	1,616,822	(6,036)	(56,420)	1,554,367	-	1,554,367
371	Inst. On Cust. Prem.	4,413,800	127,572	(21,779)	-	4,519,593	-	4,519,593
373.1	Street Light - Oh, Ug Lines	11,516,382	1,364,349	(591,596)	-	12,289,135	-	12,289,135
374	ARC Distribution	37,210	-	-	-	37,210	(37,210)	0
	TOTAL DISTRIBUTION PLANT	$ 1,927,474,753	$ 69,326,752	$ (16,575,966)	$ 423,681	$ 1,980,649,220	$ (66,831,743)	$ 1,913,817,477

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/13 to 3/31/14
Plant-In-Service

Acct No	Description	Balance 3/31/13	Actual Activity: Additions	Actual Activity: Retirements	Actual Activity: Transfers/ Adjustments	Balance 3/31/14	Adjustments	Adjusted Balance 3/31/14
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	GENERAL PLANT							
389.2	Easements	$ 18,078	$ -	$ -	$ -	$ 18,078	$ (3,028)	$ 15,050
390.1	Structures, Improvements	85,320,181	601,479	(183,603)	-	85,738,057	(14,361,125)	71,376,932
390.2	Clearing, Grading of Land	12,466,282	-	-	-	12,466,282	(2,088,102)	10,378,180
390.3	Struct Imprv, Leasehold Imp	16,754	-	-	-	16,754	(2,806)	13,948
391.1	Office Furn., Mech. Equip.	17,100,332	51,987	(521,544)	-	16,630,775	(2,785,655)	13,845,120
391.15	Office Machines	5,920,633	-	-	-	5,920,633	(991,706)	4,928,927
391.2	Data Processing Equipment	2,552,753	2,674,717	(460,109)	(140,416)	4,626,945	(775,013)	3,851,932
391.25	Data Proc Smart Meters	-	654,400	-	248,174	902,575	-	902,575
391.25	Information System	350	96,022	(351)	(107,758)	(11,738)	1,966	(9,772)
392	Transportation Equipment	1,219,015	(108,393)	-	(43,650)	1,066,971	(178,718)	888,253
393	Stores Equipment	1,428,705		(17,284)	-	1,411,422	(236,413)	1,175,009
394	Tools, Shop, Garage Equip.	10,252,799	1,774,515	(315,486)	-	11,711,828	(1,961,731)	9,750,097
395	Laboratory Equipment	3,130,477		(82,793)	-	3,047,684	(510,487)	2,537,197
396	Power Operated Equipment	642,814	108,844		-	751,658	(125,903)	625,755
397	Communication Equipment	35,658,936	432,337	(2,068,186)	-	34,023,088	(18,032,237)	15,990,851
398	Misc. Equipment	2,671,047	11,519	(96,006)	-	2,586,560	(433,249)	2,153,311
399.1	ARC General Plant	105,951	-	-	-	105,951	(105,951)	0
	TOTAL GENERAL PLANT	$ 178,505,106	$ 6,297,428	$ (3,745,361)	$ (43,650)	$ 181,013,522	$ (42,590,158)	$ 138,423,365
	TOTAL	$ 2,614,624,648	$ 107,819,642	$ (22,443,057)	$ (720,170)	$ 2,699,281,063	$ (608,676,703)	$ 2,090,604,360

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/13 to 3/31/14
Book Reserves

Acct No	Description	Balance 3/31/13	Actual Activity: Accruals	Actual Activity: Retirements	Actual Activity: Transfers/ Adjustments	Balance 3/31/14	Adjustments	Adjusted Balance 3/31/14
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	INTANGIBLE PLANT							
303	Software	$ 27,397,359	$ 3,005,012	$ -	$ -	$ 30,402,371	$ (5,092,397)	$ 25,309,974
303	Smart Meters					-	-	-
	TOTAL INTANGIBLE PLANT	$ 27,397,359	$ 3,005,012	$ -	$ -	$ 30,402,371	$ (5,092,397)	$ 25,309,974
	TRANSMISSION PLANT							
350.12	Tran Sub Easement	$ 101,129	$ 3,635	$ -	$ -	$ 104,764	$ (104,764)	$ -
350.21	Tran Line Land	7,848	(1,500)	-	1,500	7,848	(7,848)	-
350.22	Tran Line Easement	11,036,233	401,540	-	-	11,437,774	(11,437,774)	-
352	Struct PCA Dist	64,073	2,030	-	-	66,104	(66,104)	-
352	Structures/improve	2,601,010	123,758	-	(66,907)	2,657,861	(2,657,861)	-
353	Station Eq PCA Dist	1,957,015	137,550	(16,631)	690	2,078,624	(2,078,624)	-
353	Station equipment	52,321,305	2,778,769	(1,005,799)	(49,591)	54,044,683	(54,044,683)	-
354	Towers & Fixtures	26,258,318	488,672	(43,714)	-	26,703,276	(26,703,276)	-
354	Towers PCA Dist	32,855	453	-	-	33,308	(33,308)	-
355	Poles & Fixtures	17,453,861	645,971	(505,057)	-	17,594,774	(17,594,774)	-
355	Poles PCA Dist	377,154	8,518	-	-	385,672	(385,672)	-
356	OH Cond PCA Dist	282,111	6,740	-	-	288,851	(288,851)	-
356	Overhead Conductor	28,877,319	1,494,525	(550,529)	(637,663)	29,183,652	(29,183,652)	-
356.1	Clearing & R/W	3,013,311	116,179	-	(132,737)	2,996,754	(2,996,754)	-
356.1	R/W PCA Dist	309,208	90,180	-	224,116	623,504	(623,504)	-
356.2	Veg Clrng-FERC exp	-	-	-	-	-	-	-
358	UG Cond PCA Dist	209	48	-	-	257	(257)	-
358	Undergound Conductor	41,135	27,750	-	-	68,886	(68,886)	-
359	Roads & Trails	492,403	16,548	-	-	508,950	(508,950)	-
359	Roads PCA Dist	7,440	268	-	-	7,708	(7,708)	-
359.1	TXM SUB ARC	2,511	104	-	-	2,614	(2,614)	-
	TOTAL TRANSMISSION PLANT	$ 145,236,448	$ 6,341,738	$ (2,121,730)	$ (660,592)	$ 148,795,864	$ (148,795,864)	$ -
	DISTRIBUTION PLANT							
360.12	Dist Sub Easement	$ 164,777	$ 7,989	$ -	$ -	$ 172,767	$ -	$ 172,767
360.22	Dist Line Easement	13,549,839	417,008	-	-	13,966,846	-	13,966,846
361	Structure/Improve	5,601,618	313,171	(2,322)	-	5,912,467	-	5,912,467
361.2	Grading Clearing	9,260	5,361	-	-	14,621	-	14,621
362	Station equipment	69,591,323	3,952,890	(1,401,555)	(678,681)	71,463,977	-	71,463,977
364	Poles towers fix	101,435,336	4,674,572	(1,998,952)	-	104,110,956	-	104,110,956
365	Overhead conductor	74,288,389	7,207,288	(5,548,499)	(1,189,114)	74,758,065	-	74,758,065
365.1	Clearing & R/W	15,024,997	1,928,590	-	(24,472)	16,929,114	-	16,929,114
366	Underground conduit	10,326,967	528,703	(7,411)	-	10,848,259	-	10,848,259
367	Undergrd conductor	62,131,972	5,637,837	(1,549,128)	-	66,220,681	-	66,220,681
368	Line Transformers	120,583,394	8,795,800	(3,933,333)	(460,994)	124,984,867	-	124,984,867
369	Services OH	16,527,158	4,339,839	(62,001)	(2,725,516)	18,079,480	-	18,079,480
369	Unground Services	44,295,950	2,219,858	-	-	46,515,808	-	46,515,808
370	Meters	10,867,039	2,669,623	(1,453,354)	1,279	12,084,587	(12,084,587)	-
370	Smart Meters Res	-	56,836	(6,036)	(1,279)	49,520	-	49,520
371	Inst on cust prem	1,753,450	122,894	(21,779)	-	1,854,566	-	1,854,566
371	Meter Socket dvc 125	169	8	-	-	177	-	177
371	Meter Socket dvc 126	169	8	-	-	177	-	177
371	Meter Socket dvc 127	346	15	-	-	361	-	361
371	Meter Socket dvc 1PH	288,092	13,242	-	-	301,334	-	301,334
371	Meter Socket dvc 3PH	246	11	-	-	258	-	258
371	Surge Suppression 2	240,849	-	-	-	240,849	-	240,849
371	Surge Suppression 4	35,859	-	-	-	35,859	-	35,859
373	Street Lighting	3,112,557	(69,008)	(591,596)	387,276	2,839,229	-	2,839,229
374	DIST SUB ARC	20,672	759	-	-	21,431	(21,431)	-
	TOTAL DISTRIBUTION PLANT	$ 549,850,430	$ 42,823,293	$ (16,575,966)	$ (4,691,502)	$ 571,406,256	$ (12,106,018)	$ 559,300,238
	GENERAL PLANT							
389.2	Land Rights	$ 14,800	$ 407	$ -	$ -	$ 15,207	$ (2,547)	$ 12,659
390.1	Easton Serv Center	3,766,087	322,148	(78,737)	-	4,009,499	(671,591)	3,337,908
390.1	Lebanon Serv Ctr	3,035,180	188,469	(104,866)	-	3,118,784	(522,396)	2,596,388
390.1	South Bldg Reading	24,249,976	1,092,299	-	-	25,342,274	(4,244,831)	21,097,443
390.1	Structures	7,426,845	488,341	-	(85,549)	7,829,637	(1,311,464)	6,518,173
390.1	York Serv Center	3,773,706	209,705	-	-	3,983,411	(667,221)	3,316,189
390.2	Corp Hqtrs Reading	1,623,551	90,647	-	-	1,714,197	(287,128)	1,427,069
390.2	Easton Ser Ctr	756,468	116,782	-	-	873,250	(146,269)	726,981
390.2	Land/Yard Improvem	2,666,882	169,861	-	-	2,836,743	(475,154)	2,361,588
390.2	Lebanon Ser Ctr	770,154	23,374	-	-	793,528	(132,916)	660,612
390.2	York Ser Ctr	1,096,229	46,769	-	-	1,142,997	(191,452)	951,545
390.3	Transfered LH	3,456	838	-	-	4,293	(719)	3,574
391.1	Office Furniture	14,419,236	748,509	(521,544)	-	14,646,201	(2,453,239)	12,192,962
391.15	Office Machines	5,920,633	-	-	-	5,920,633	(991,706)	4,928,927
391.2	Personal Computers	1,964,996	747,802	(460,109)	(12,498)	2,240,191	(375,232)	1,864,959
391.25	Data Proc Smart Me	-	72,062	-	14,012	86,074	-	86,074
391.25	Information Sys	256	(1,337)	(351)	(1,513)	(2,944)	493	(2,451)
392	Transportation equip	51,829	34,679	-	(7,004)	79,504	(13,317)	66,187
392.4	Pole Trailers	435,261	25,554	-	-	460,815	(77,186)	383,628
392.5	Van Trailers	78,354	717	-	-	79,071	(13,244)	65,826
393	Stores Equipment	1,390,709	30,785	(17,284)	-	1,404,210	(235,205)	1,169,005
394	Tools shop garage	6,491,729	508,233	(315,486)	-	6,684,476	(1,119,650)	5,564,826
395	Laboratory equip	3,130,011	466	(82,793)	-	3,047,684	(510,487)	2,537,197

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/13 to 3/31/14
Book Reserves

Acct No	Description	Balance 3/31/13	Actual Activity			Balance 3/31/14	Adjustments	Adjusted Balance 3/31/14
			Accruals	Retirements	Transfers/ Adjustments			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
396	Power operated equip	609,115	4,001	-	-	613,115	(102,697)	510,418
397	Communication Equipt	25,010,698	975,149	(2,068,186)	(4,130)	23,913,531	(12,674,172)	11,239,360
398	Miscellaneous equipt	2,539,048	62,418	(96,006)	-	2,505,460	(419,665)	2,085,795
399	EASTON BLDG ARC	3,776	145	-	-	3,921	(3,921)	-
399	GEN BLDG ARC	28,466	1,193	-	-	29,659	(29,659)	-
399	LEBANON BLDG ARC	3,875	150	-	-	4,024	(4,024)	-
399	READING SOUTH BLDG ARC	7,658	277	-	-	7,935	(7,935)	-
399	YORK BLDG ARC	2,641	101	-	-	2,742	(2,742)	-
	TOTAL GENERAL PLANT	$ 111,271,623	$ 5,960,544	$ (3,745,361)	$ (96,684)	$ 113,390,122	$ (27,687,278)	$ 85,702,844
	NUCLEAR PRODUCTION							
326	TMI#2 ARC	$ 95,321,154	$ -	$ -	$ -	$ 95,321,154	$ (95,321,154)	$ -
Total	TOTAL	$ 929,077,014	$ 58,130,587	$ (22,443,057)	$ (5,448,778)	$ 959,315,767	$ (289,002,712)	$ 670,313,056

Metropolitan Edison Company
Original Cost - Plant and Depreciation Reserves
Activity Updated from 3/31/13 to 3/31/14
Calculated Reserves

Acct No	Description	Balance 3/31/13	Actual Activity			Balance 3/31/14	Adjustments	Adjusted Balance 3/31/14
			Accruals	Retirements	Transfers/ Adjustments			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	INTANGIBLE PLANT							
303	Misc. Intangible Plant	$ 27,072,400	$ 5,331,902	$ -	$ -	$ 32,404,302	$ (5,427,721)	$ 26,976,581
303	Smart Meter Software		-			-	-	-
	TOTAL INTANGIBLE PLANT	$ 27,072,400	$ 5,331,902	$ -	$ -	$ 32,404,302	$ (5,427,721)	$ 26,976,581
	TRANSMISSION PLANT							
	TRANSMISSION PLANT							
350.12	Easements - Trans. Subs.	$ 101,129	$ 4,372	$ -	$ -	$ 105,501	$ (105,501)	$ -
350.22	Easements - Trans. Lines	13,729,903	401,402	-	-	14,131,305	(14,131,305)	-
352.1	Structures, Improvements	2,939,395	111,806	-	-	3,051,201	(3,051,201)	-
352.2	Clearing, Grading Of Land	0	8,823	-	-	8,823	(8,823)	-
353	Station Equipment	41,128,807	2,904,546	(1,022,430)	-	43,010,923	(43,010,923)	-
354	Towers And Fixtures	21,584,172	494,114	(43,714)	-	22,034,572	(22,034,572)	-
355	Poles And Fixtures	14,341,588	646,711	(505,057)	-	14,483,242	(14,483,242)	-
356.1	Overhd Conductr, Devices	22,209,775	867,618	(550,529)	-	22,526,864	(22,526,864)	-
356.2	Clearing, Grading of Land	3,137,912	188,225	-	-	3,326,137	(3,326,137)	-
358	Undergrnd Conductr,Devices	23,958	27,241	-	-	51,199	(51,199)	-
359	Roads And Trails	527,886	16,807	-	-	544,693	(544,693)	-
359.1	ARC Transmission	2,511	104	-	-	2,614	(2,614)	-
	TOTAL TRANSMISSION PLANT	$ 119,727,036	$ 5,671,769	$ (2,121,730)	$ -	$ 123,277,074	$ (123,277,074)	$ -
	DISTRIBUTION PLANT							
360.12	Easements - Dist. Subs.	$ 164,777	$ 7,253	$ -	$ -	$ 172,030	$ -	$ 172,030
360.22	Easements - Dist. Lines	12,873,434	416,315	-	-	13,289,749	-	13,289,749
361.1	Structures, Improvements	5,601,618	312,690	(2,322)	-	5,911,986	-	5,911,986
361.2	Clearing, Grading of Land	713,597	6,105	-	-	719,702	-	719,702
362	Station Equipment	54,799,027	3,102,128	(1,401,555)	-	56,499,600	-	56,499,600
364	Poles, Towers And Fixtures	60,912,239	4,973,748	(1,998,952)	-	63,887,035	-	63,887,035
365	Overhd Conductr, Devices	52,167,632	5,793,852	(5,548,499)	-	52,412,985	-	52,412,985
365.1	Clearing, Grading of Land	14,236,200	1,940,552	-	-	16,176,752	-	16,176,752
366	Underground Conduit	11,237,934	529,598	(7,411)	-	11,760,121	-	11,760,121
367	Undergrnd Conductr,Devices	61,866,658	5,611,391	(1,549,128)	-	65,928,921	-	65,928,921
368	Line Transformers	90,139,633	8,360,742	(3,933,333)	-	94,567,042	-	94,567,042
369	Services	14,812,424	1,605,057	(62,001)	-	16,355,480	-	16,355,480
369	Underground Conduit	39,820,229	2,215,323	-	-	42,035,552	-	42,035,552
370	Meters	9,631,099	2,670,943	(1,453,354)	-	10,848,688	(10,848,688)	0
370	Smart Meters Res	-	49,957	(6,036)	-	43,921	-	43,921
371	Inst. On Cust. Prem.	1,710,387	144,274	(21,779)	-	1,832,882	-	1,832,882
373.1	Street Light - Oh, Ug Lines	2,063,532	310,662	(591,596)	-	1,782,598	-	1,782,598
374	ARC Distribution	20,672	759	-		21,431	(21,431)	0
	TOTAL DISTRIBUTION PLANT	$ 432,771,092	$ 38,051,349	$ (16,575,966)	$ -	$ 454,246,475	$ (10,870,119)	$ 443,376,357
	GENERAL PLANT							
389.2	Easements	$ 15,175	$ 407	$ -	$ -	$ 15,582	$ (2,610)	$ 12,972
390.1	Structures, Improvements	37,467,445	2,360,604	(183,603)	-	39,644,446	(6,640,445)	33,004,001
390.2	Clearing, Grading of Land	7,309,879	344,069	-	-	7,653,948	(1,282,036)	6,371,912
390.3	Struct Imprv, Leasehold Imp	3,455	462	-	-	3,917	(656)	3,261
391.1	Office Furn., Mech. Equip.	14,074,756	1,010,247	(521,544)	-	14,563,459	(2,439,379)	12,124,080
391.15	Office Machines	5,920,633	354,646	-	-	6,275,279	(1,051,109)	5,224,170
391.2	Data Processing Equipment	1,728,980	210,826	(460,109)	-	1,479,697	(247,849)	1,231,848
391.25	Data Proc Smart Meters	-	115,075	-	-	115,075	-	115,075
391.25	Information System	381	(3,568)	(351)	-	(3,538)	593	(2,946)
392	Transportation Equipment	535,602	67,046	-	-	602,648	(100,944)	501,704
393	Stores Equipment	1,331,196	30,815	(17,284)	-	1,344,727	(225,242)	1,119,486
394	Tools, Shop, Garage Equip.	6,832,459	482,124	(315,486)	-	6,999,097	(1,172,349)	5,826,748
395	Laboratory Equipment	2,967,426	618	(82,793)	-	2,885,251	(483,280)	2,401,972
396	Power Operated Equipment	335,908	3,905	-	-	339,813	(56,919)	282,894
397	Communication Equipment	17,348,936	996,453	(2,068,186)	-	16,277,203	(8,626,918)	7,650,286
398	Misc. Equipment	2,377,848	62,828	(96,006)	-	2,344,670	(392,732)	1,951,938
399.1	ARC General Plant	46,416	1,866	-		48,282	(48,282)	-
	TOTAL GENERAL PLANT	$ 98,296,495	$ 6,038,423	$ (3,745,361)	$ -	$ 100,589,557	$ (22,770,157)	$ 77,819,400
	TOTAL	$ 677,867,022	$ 55,093,443	$ (22,443,057)	$ -	$ 710,517,409	$ (162,345,070)	$ 548,172,338

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT V-A-3:

"Provide supporting schedules which indicate the procedures and calculations employed to develop the original cost plant and applicable reserves to the test year end as submitted in the current proceeding."

RESPONSE:

Met-Ed Exhibit RAD- 49 Attachment A presents the example showing the methodology used to update original cost plant and reserves from 3/31/13 to 3/31/14 (the historic test year-end) and to 3/31/15 (the future test year-end) and to 4/30/2016 (the fully future test year). The procedure applied is the same as has been used and found acceptable in prior base rate cases for projecting the future year original cost plant related data.

The example depicts a mass property remaining life investment set, Account 373, Street Lighting and Signal Systems.

Metropolitan Edison Company
Original Cost-Plant & Depreciation Reserves
Activity Updated from 3/31/13 through 3/31/14 and 3/31/15 and 4/30/16

MASS PROPERTY EXAMPLE

Line No	Description	Plant in Service	Target Reserves	Book Reserves
		(1)	(2)	(3)
	Distribution - 373.1 Street Lighting & Signal Systems			
1	Balance at 3/31/13	11,516,382	2,063,532	3,112,557
2	Accrual on Above		300,578	
3	Retirements	(591,596)	(591,596)	(591,596)
4	Accrual on Retirements		(7,720)	
5	Transfers & Adjustments	-	-	
6	Accrual on Transfers & Adjustments		-	
7	Additions	1,364,349		
8	Accrual on Additions		17,805	
9	Book Accrual			(69,008)
10	Book Activity-Other			387,276
11	Balance at 3/31/14	12,289,135	1,782,599	2,839,229
12	Accrual on 3/31/14 Plant		320,746	
13	Retirements	-	-	-
14	Accrual on Retirements		-	
15	Transfers & Adjustments	-	-	
16	Accrual on Transfers & Adjustments		-	
17	Additions	-		
18	Accrual on Additions		-	
19	Book Accrual			321,122
20	Book Activity-Other			-
21	Balance at 3/31/15	12,289,135	2,103,345	3,160,351
12	Accrual on 4/30/15 Plant		320,746	
13	Retirements	-	-	-
14	Accrual on Retirements		-	
15	Transfers & Adjustments	-	-	
16	Accrual on Transfers & Adjustments		-	
17	Additions	-		
18	Accrual on Additions		-	
19	Book Accrual			321,122
20	Book Activity-Other			-
21	Balance at 4/30/16	12,289,135	2,424,091	3,481,473

Key to Rates:

2012 Depreciation Service Life Accrual Rate 2.61%

METROPOLITAN EDISON COMPANY

Original Cost Plant and Reserve and Accrual Rate Adjustments for Rate Case Purposes
(Fully Projected Future Test Year)

FILING REQUIREMENT V-A-4:

"Provide a schedule showing details of rate case adjustments."

RESPONSE:

This response provides original cost plant and reserve adjustments for rate case purposes at 4/30/16, the fully projected future test year-ended. This information is in support of Met-Ed Exhibit RAD-46 Attachment B.

The following provide detail for plant and reserve adjustment items:

1. Asset Retirement Costs: No claim is being made for the Asset Retirement Costs related to the implementation of Statement of Financial Accounting Standards Statement 143, Accounting for Asset Retirement Obligations or FIN 47, Accounting for Conditional Asset Retirement Obligations. The Plant in Service was reduced by $95,358,364; book reserves were reduced by $95,344,166; and calculated reserves were reduced by $22,949.

2. FERC Transmission Plant was removed because it is non-jurisdictional. Transmission Plant in Service was reduced by $454,163,285 and the budgeted book and calculated reserve accruals were reduced by $155,934,333 and $130,390,153 respectively.

3. A portion of Intangible Plant associated with the FERC Transmission Plant was removed. Intangible Plant in Service was reduced by $9,694,591; Intangible Plant book reserves were reduced by $6,012,241; and Intangible Plant calculated reserves were reduced by $7,444,387.

4. A portion of General Plant associated with FERC Transmission Plant was removed. General Plant in Service was reduced by $43,569,748; General Plant book reserves were reduced by $30,270,230; and General Plant calculated reserves were reduced by $25,593,811.

5. Legacy meters were removed. Meter plant in service was reduced by $66,794,533; meter book reserves were reduced by $16,631,748; and meter calculated reserves were reduced by $16,672,615.

METROPOLITAN EDISON COMPANY

Original Cost Plant and Reserve and Accrual Rate Adjustments for Rate Case Purposes
(Future Test Year)

FILING REQUIREMENT V-A-4:

"Provide a schedule showing details of rate case adjustments."

RESPONSE:

This response provides original cost plant and reserve adjustments for rate case purposes at 3/31/15, the future test year-ended. This information is in support of Met-Ed Exhibit RAD-47 Attachment B.

The following provide detail for plant and reserve adjustment items:

1. Asset Retirement Costs: No claim is being made for the Asset Retirement Costs related to the implementation of Statement of Financial Accounting Standards Statement 143, Accounting for Asset Retirement Obligations or FIN 47, Accounting for Conditional Asset Retirement Obligations. The Plant in Service was reduced by $95,358,364; book reserves were reduced by $95,343,344; and calculated reserves were reduced by $22,190.

2. FERC Transmission Plant was removed because it is non-jurisdictional. Transmission Plant in Service was reduced by $433,209,181 and the budgeted book and calculated reserve accruals were reduced by $151,083,591 and $125,510,429 respectively.

3. A portion of Intangible Plant associated with the FERC Transmission Plant was removed. Intangible Plant in Service was reduced by $6,968,446; Intangible Plant book reserves were reduced by $5,488,712; and Intangible Plant calculated reserves were reduced by $6,292,334.

4. A portion of General Plant associated with FERC Transmission Plant was removed. General Plant in Service was reduced by $43,409,672; General Plant book reserves were reduced by $28,831,646; and General Plant calculated reserves were reduced by $23,934,946.

5. Legacy meters were removed. Meter plant in service was reduced by $66,794,533; meter book reserves were reduced by $14,727,733; and meter calculated reserves were reduced by $13,647,379.

METROPOLITAN EDISON COMPANY

Original Cost Plant and Reserve and Accrual Rate Adjustments for Rate Case Purposes
(Historical Test Year)

FILING REQUIREMENT V-A-4:

"Provide a schedule showing details of rate case adjustments."

RESPONSE:

This response provides original cost plant and reserve adjustments for rate case purposes at 3/31/14, the historic test year-ended. This information is in support of Met-Ed Exhibit RAD-48 Attachment B.

The following provide detail for plant and reserve adjustment items:

1. Asset Retirement Costs: No claim is being made for the Asset Retirement Costs related to the implementation of Statement of Financial Accounting Standards Statement 143, Accounting for Asset Retirement Obligations or FIN 47, Accounting for Conditional Asset Retirement Obligations. The Plant in Service was reduced by $95,358,364; book reserves were reduced by $95,342,585; and calculated reserves were reduced by $22,190.

2. FERC Transmission Plant was removed because it is non-jurisdictional. Transmission Plant in Service was reduced by $397,455,541 and the budgeted book and calculated reserve accruals were reduced by $148,795,864 and $123,277,074 respectively.

3. A portion of Intangible Plant associated with the FERC Transmission Plant was removed. Intangible Plant in Service was reduced by $6,478,107; Intangible Plant book reserves were reduced by $5,092,397; and Intangible Plant calculated reserves were reduced by $5,427,721.

4. A portion of General Plant associated with FERC Transmission Plant was removed. General Plant in Service was reduced by $42,590,158; General Plant book reserves were reduced by $27,687,278; and General Plant calculated reserves were reduced by $22,770,157.

5. Legacy Meters were removed. Meter plant in service was reduced by $66,794,533; meter book reserves were reduced by $12,084,587; and meter calculated reserves were reduced by $10,848,688.

METROPOLITAN EDISON COMPANY

Annual Depreciation Review on Capital Plant Investments

FILING REQUIREMENT V-B-2

"Supply a schedule by account or by depreciable group showing the survivor curve or interim survivor curve or interim survivor curse and annual accrual rate estimated to be appropriate:

a. For the purpose of this filing
b. For the purposes of the most recent filing prior to the current proceeding.
c. Supply an explanation for any major change in annual accrual rate by account or by depreciable group
d. Supply a comprehensive statement of major changes in depreciation methods, procedures and techniques and the effect of the changes upon accumulated and annual depreciation, if any."

FILING REQUIREMENT V-C

"Where the retirement rate actuarial method of mortality is utilized, set forth representative examples including charts depicting the observed and estimated survivor curves and a tabular presentation of the observed and estimated life tables plotted on the chart. Other analysis results shall be subject to request."

FILING REQUIREMENT V-D Item 2

"Provide representative examples of detail calculations by vintage at account or at a more detailed level, as performed for those purposes. Other vintage detail calculations shall be subject to request."

FILING REQUIREMENT V-E

"Provide a description of depreciation methods utilized in calculating annual depreciation amounts and depreciation reserves, together with a discussion of significant factors which were considered in arriving at estimates of service life and forecast retirements by facilities, accounts or sub-accounts as applicable."

RESPONSE:

V-B-2:

See Met-Ed Exhibit RAD-53 Attachment A, Pages 1-2 for the fully projected future test year. See Met-Ed Exhibit RAD-53 Attachment A, Pages 3-4 for the future test year. See Met-Ed Exhibit RAD-53 Attachment A, pages 5-6 for the historical test year.

See Met-Ed Exhibit RAD-53 Attachment B for the 2014 Annual Depreciation Report.

V-C:

See Met-Ed Exhibit RAD-53 Attachment C.

V-D Item 2:

See Met-Ed Exhibit RAD-53 Attachment D for Annual Depreciation Report details.

V-E:

See Met-Ed Exhibit RAD-53 Attachment B for the 2014 Annual Depreciation Report.

Metropolitan Edison Company
Accrual Expense after Adjustment-Claim Basis
At Future Year from May 2015 to April 2016

Acct No	Description	Adjusted Depreciable Base	Accrual Rate Ave Remaining Life Basis	Accrual Expense Amount
		(1)	(2)	(3)
	INTANGIBLE PLANT			
303	Miscellaneous Intangible Plant	$ 48,183,564	12.86%	$ 6,196,406
303	Smart Meters	13,103,518	14.29%	1,872,493
	TOTAL INTANGIBLE PLANT	$ 61,287,082	13.17%	$ 8,068,899
	TRANSMISSION PLANT			
	TRANSMISSION PLANT			
350.12	Land Rights- subs	$ -	1.50%	$ -
350.22	Land Rights- lines	-	1.50%	-
352.1	Structures	-	1.84%	-
352.2	Clearing Costs	-	1.84%	-
353	Station Equipment	-	1.68%	-
354	Towers and Fixtures	-	1.16%	-
355	Poles and Fixtures	-	1.46%	-
3356.1	Overhead Conductors	-	1.32%	-
356.2	Clearing Costs	-	1.23%	-
358	Underground Conductors	-	2.51%	-
359	Roads & Trails	-	2.25%	-
	TOTAL TRANSMISSION PLANT	$ -		$ -
	DISTRIBUTION PLANT			
360.12	Land Rights-subs	$ 611,470	1.47%	$ 8,989
360.22	Land Rights-lines	28,320,720	1.47%	
361.1	Structures	12,746,076	2.43%	309,730
361.2	Clearing Costs	366,045	2.43%	
362	Station Equipment	216,797,725	1.56%	3,382,045
364	Poles, Towers and Fixtures	354,210,686	1.32%	4,675,581
365	Overhead Conductors	368,193,014	1.71%	6,296,101
365.1	Clearing Costs	131,739,866	1.52%	2,002,446
366	Underground Conduit	30,296,760	1.74%	527,164
367	Underground Conductors	203,212,529	2.85%	5,791,557
368	Line Transformers	502,265,379	2.14%	10,748,479
369	Overhead Services	71,066,339	2.28%	1,620,313
369.1	Underground Services	98,458,792	2.23%	2,195,631
370	Meters	0	4.19%	0
370.1	Smart Meters	11,620,142	6.67%	775,063
371	Installed on Customer Premises	4,519,593	3.19%	144,175
373	Street Lighting & Signal Systems	12,289,135	2.77%	340,409
	TOTAL DISTRIBUTION PLANT	$ 2,046,714,271	1.90%	$ 38,817,683

Metropolitan Edison Company
Accrual Expense after Adjustment-Claim Basis
At Future Year from May 2015 to April 2016

Acct No	Description	Adjusted Depreciable Base	Accrual Rate Ave Remaining Life Basis	Accrual Expense Amount
		(1)	(2)	(3)
	GENERAL PLANT			
389.1	Land Rights	$ 15,050	2.21%	$ 333
390.1	Structures	72,817,578	2.45%	1,784,031
390.2	Clearing	10,378,180	3.52%	365,312
390.3	Structures and Improvements LH	13,948	3.52%	491
391.1	Office Furniture & Equipment	13,845,120	4.12%	570,419
391.15	Office Machines	4,928,927	0.00%	0
391.2	Data Processing	3,851,932	6.72%	258,850
391.25	Data Processing Smart Meters	9,299,254	20.00%	1,859,851
391.25	Information Systems	(9,772)	13.03%	(1,273)
392	Transportation	4,316,320	4.76%	205,457
393	Stores Equipment	1,175,009	0.88%	10,340
394	Tools, Shop, & Garage Equipment	9,750,097	4.19%	408,529
395	Laboratory Equipment	2,537,197	0.00%	25
396	Power Operated Equipment	625,755	1.72%	10,763
397	Communications Equipment	15,990,851	3.01%	481,325
398	Miscellaneous Equipment	2,153,311	1.84%	39,621
	TOTAL GENERAL PLANT	$ 151,688,757	3.95%	$ 5,994,074
	TOTAL	$ 2,259,690,109	2.34%	$ 52,880,656

Metropolitan Edison Company
Accrual Expense after Adjustment-Claim Basis
At Future Year from April 2014 to March 2015

Acct No	Description	Adjusted Depreciable Base	Accrual Rate Ave Remaining Life Basis	Accrual Expense Amount
		(1)	(2)	(3)
	INTANGIBLE PLANT			
303	Miscellaneous Intangible Plant	$ 34,634,219	12.86%	$ 4,453,961
303	Smart Meters	2,159,907	14.29%	308,651
	TOTAL INTANGIBLE PLANT	$ 36,794,126	12.94%	$ 4,762,612
	TRANSMISSION PLANT			
	TRANSMISSION PLANT			
350.12	Land Rights- subs	$ -	1.50%	$ -
350.22	Land Rights- lines	-	1.50%	-
352.1	Structures	-	1.84%	-
352.2	Clearing Costs	-	1.84%	-
353	Station Equipment	-	1.68%	-
354	Towers and Fixtures	-	1.16%	-
355	Poles and Fixtures	-	1.46%	-
3356.1	Overhead Conductors	-	1.32%	-
356.2	Clearing Costs	-	1.23%	-
358	Underground Conductors	-	2.51%	-
359	Roads & Trails	-	2.25%	-
	TOTAL TRANSMISSION PLANT	$ -		$ -
	DISTRIBUTION PLANT			
360.12	Land Rights-subs	$ 611,470	1.47%	$ 8,989
360.22	Land Rights-lines	28,320,720	1.47%	
361.1	Structures	12,746,076	2.43%	309,730
361.2	Clearing Costs	366,045	2.43%	
362	Station Equipment	212,972,648	1.56%	3,322,373
364	Poles, Towers and Fixtures	354,210,686	1.32%	4,675,581
365	Overhead Conductors	368,193,014	1.71%	6,296,101
365.1	Clearing Costs	131,739,866	1.52%	2,002,446
366	Underground Conduit	30,296,760	1.74%	527,164
367	Underground Conductors	203,212,529	2.85%	5,791,557
368	Line Transformers	450,297,576	2.14%	9,636,368
369	Overhead Services	71,066,339	2.28%	1,620,313
369.1	Underground Services	98,458,792	2.23%	2,195,631
370	Meters	0	4.19%	0
370.1	Smart Meters	2,241,360	6.67%	149,499
371	Installed on Customer Premises	4,519,593	3.19%	144,175
373	Street Lighting & Signal Systems	12,289,135	2.77%	340,409
	TOTAL DISTRIBUTION PLANT	$ 1,981,542,609	1.87%	$ 37,020,336

Metropolitan Edison Company
Accrual Expense after Adjustment-Claim Basis
At Future Year from April 2014 to March 2015

Acct No	Description	Adjusted Depreciable Base	Accrual Rate Ave Remaining Life Basis	Accrual Expense Amount
		(1)	(2)	(3)
	GENERAL PLANT			
389.1	Land Rights	$ 15,050	2.21%	$ 333
390.1	Structures	72,817,247	2.45%	1,784,023
390.2	Clearing	10,378,180	3.52%	365,312
390.3	Structures and Improvements LH	13,948	3.52%	491
391.1	Office Furniture & Equipment	13,845,120	4.12%	570,419
391.15	Office Machines	4,928,927	0.00%	0
391.2	Data Processing	3,851,932	6.72%	258,850
391.25	Data Processing Smart Meters	6,355,799	20.00%	1,271,160
391.25	Information Systems	(9,772)	13.03%	(1,273)
392	Transportation	3,521,048	4.76%	167,602
393	Stores Equipment	1,175,009	0.88%	10,340
394	Tools, Shop, & Garage Equipment	9,750,097	4.19%	408,529
395	Laboratory Equipment	2,537,197	0.00%	25
396	Power Operated Equipment	625,755	1.72%	10,763
397	Communications Equipment	15,990,851	3.01%	481,325
398	Miscellaneous Equipment	2,153,311	1.84%	39,621
	TOTAL GENERAL PLANT	$ 147,949,698	3.63%	$ 5,367,520
	TOTAL	$ 2,166,286,433	2.18%	$ 47,150,468

Metropolitan Edison Company
Accrual Expense after Adjustment-Claim Basis
At Future Year from April 2013 to March 2014

Acct No	Description	Adjusted Depreciable Base (1)	Accrual Rate Ave Remaining Life Basis (2)	Accrual Expense Amount (3)
	INTANGIBLE PLANT			
303	Miscellaneous Intangible Plant	$ 32,197,158	13.85%	$ 4,459,306
303	Smart Meters	0	14.29%	0
	TOTAL INTANGIBLE PLANT	$ 32,197,158	13.85%	$ 4,459,306
	TRANSMISSION PLANT			
	TRANSMISSION PLANT			
350.12	Land Rights- subs	$ -	1.50%	$ -
350.22	Land Rights- lines	0	1.50%	
352.1	Structures	0	1.83%	0
352.2	Clearing Costs	0	1.83%	
353	Station Equipment	0	1.66%	0
354	Towers and Fixtures	0	1.19%	0
355	Poles and Fixtures	0	1.43%	0
356.1	Overhead Conductors	0	1.29%	0
356.2	Clearing Costs	0	1.23%	0
358	Underground Conductors	0	2.46%	0
359	Roads & Trails	0	2.25%	0
	TOTAL TRANSMISSION PLANT	$ -		$ -
	DISTRIBUTION PLANT			
360.12	Land Rights-subs	$ 611,470	1.47%	$ 8,989
360.22	Land Rights-lines	28,320,720	1.47%	
361.1	Structures	12,746,076	2.46%	313,553
361.2	Clearing Costs	366,045	2.46%	
362	Station Equipment	203,494,152	1.54%	3,133,810
364	Poles, Towers and Fixtures	354,210,686	1.35%	4,781,844
365	Overhead Conductors	368,193,014	1.67%	6,148,823
365.1	Clearing Costs	131,739,866	1.53%	2,015,620
366	Underground Conduit	30,296,760	1.75%	530,193
367	Underground Conductors	203,212,529	2.85%	5,791,557
368	Line Transformers	392,737,933	2.14%	8,404,592
369	Overhead Services	71,066,339	2.30%	1,634,526
369.1	Underground Services	98,458,792	2.25%	2,215,323
370	Meters	-	4.07%	-
370.1	Smart Meters	1,554,367	6.67%	103,676
371	Installed on Customer Premises	4,519,593	3.23%	145,983
373	Street Lighting & Signal Systems	12,289,135	2.61%	320,746
	TOTAL DISTRIBUTION PLANT	$ 1,913,817,477	1.86%	$ 35,549,235

Metropolitan Edison Company
Accrual Expense after Adjustment-Claim Basis
At Future Year from April 2013 to March 2014

Acct No	Description	Adjusted Depreciable Base	Accrual Rate Ave Remaining Life Basis	Accrual Expense Amount
		(1)	(2)	(3)
	GENERAL PLANT			
389.1	Land Rights	$ 15,050	2.25%	$ 339
390.1	Structures	71,376,932	2.76%	1,970,003
390.2	Clearing	10,378,180	2.76%	286,438
390.3	Structures and Improvements LH	13,948	2.76%	385
391.1	Office Furniture & Equipment	13,845,120	5.99%	829,323
391.15	Office Machines	4,928,927	5.99%	295,243
391.2	Data Processing	3,851,932	5.99%	230,731
391.25	Data Processing Smart Meters	902,575	20.00%	180,515
391.25	Information Systems	(9,772)	5.99%	(585)
392	Transportation	888,253	5.98%	53,118
393	Stores Equipment	1,175,009	2.17%	25,498
394	Tools, Shop, & Garage Equipment	9,750,097	4.39%	428,029
395	Laboratory Equipment	2,537,197	0.02%	507
396	Power Operated Equipment	625,755	0.56%	3,504
397	Communications Equipment	15,990,851	2.86%	457,338
398	Miscellaneous Equipment	2,153,311	2.39%	51,464
	TOTAL GENERAL PLANT	$ 138,423,365	3.48%	$ 4,811,850
	TOTAL	$ 2,084,438,000	2.15%	$ 44,820,391

METROPOLITAN EDISON COMPANY

2014 Annual Depreciation Report
Based on Data at 12/31/2013

To the Pennsylvania Public Utility Commission
Per Reference No. M-110300F2013ADR

June 2014

METROPOLITAN EDISON COMPANY

2014 Annual Depreciation Report
Based on Data at 12/31/2013

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METROPOLITAN EDISON COMPANY
2014 ANNUAL DEPRECIATION REPORT
YEAR ENDED DECEMBER, 31, 2013
EXECUTIVE SUMMARY

Introduction

In accordance with 52 Pa. Code, Chapter 73, the attached report provides the following:

- A summary of plant transactions, including the 2013 retirements expressed as a percent of the beginning plant balance
- A summary of depreciation reserve activity, including the reserve as a percent of the plant balance
- The calculation of remaining life depreciation accrual rates as of December 31, 2013
- A summary of cost of removal, gross and net salvage.

Metropolitan Edison Company (Met-Ed) is requesting the Pennsylvania Public Utility Commission (PaPUC) to approve this filing, for accounting purposes only, so that the new depreciation rates can be implemented effective January 1, 2014 to be consistent across all FirstEnergy Pennsylvania Operating Companies.

The annual accrual rate calculations are based on a depreciation service life study of Transmission, Distribution and General Plant data filed with the PaPUC in 2010 that included data through the year ended 2009. The annual accrual rate calculations were based on the same service life and survivor curve estimates and also on the same group procedures and basis as those submitted to the PaPUC in 2010.

Included with this Executive Summary is a table that sets forth a comparison of the original cost, book reserve and calculated annual depreciation accruals by function at December 31, 2011; December 31, 2012; and December 31, 2013. The annual accrual amounts, as summarized, are presented as a percent of original cost for each function and for the total Company. The overall composite depreciation accrual rate related to depreciable electric plant in service decreased from 2.09 percent in 2012 to 2.08 percent for 2013.

Depreciation Method

For most plant accounts, depreciation accruals and accrued depreciation were calculated using the straight line remaining life method and the average service life broad group (ASL-BG) procedure for all vintages.

The depreciation calculations were based on the attained ages and estimated service life characteristics for each depreciable group of electric plant. For certain general plant accounts, the amortization amounts, annual and accrued, were based on the age of the vintage and the selected amortization period.

The service life study filed with the PaPUC in 2010 determined the appropriate service life and survivor curves utilized in the accrual rate calculations as explained further below.

Service Life

The method of estimating service life consisted of compiling the service life history of the plant accounts, sub-accounts or depreciable groups through 2009. The history was then reduced to trends through the use of acceptable actuarial techniques. Lastly, the trend of survivors for each depreciable group was forecasted on the basis of interpretations of past trends and consideration of Company plans for the future. The combination of the historical trend and the estimated future trend developed a complete pattern of life characteristics from which the average service life was derived.

Survivor Curves

Iowa type survivor curves were used to reflect the expected dispersion of retirements, thus providing a consistent method of estimating service lives and depreciation for mass property. For life span groups, the estimate of life characteristics is consistent because the calculated lives of the units within a group are obtained by employing a single probable retirement date for the entire group.

Plant and Reserve Activity

Schedule 1 provides the net original cost balance at December 31, 2013, the average service life and the Iowa Survivor Curve for each account along with the average remaining life, annual depreciation accrual and accrual rate. The functional plant level accrual rates for 2013 did not change significantly from 2012.

Schedule 2 provides the plant activity during 2013 by account and functional group. It sets forth the original cost at the beginning of the year, January 1, 2013; additions; retirements; transfers or adjustments; the balance at the end of the year, December 31, 2013; and the retirements expressed as a percent of the beginning plant balance.

Schedule 3 summarizes the reserve activity during 2013 by account and functional group. It includes the book depreciation reserve balance at the beginning of the year, January 1, 2013; annual accruals; retirements; gross salvage; cost of removal; transfers or adjustments; the balance at the end of the year, December 31, 2013; and the book reserve as a percent of the ending plant balance.

Net Salvage Analysis

Schedule 4 reports the 2013 and a five year rolling average for Cost of Removal, Gross and Net Salvage. The five-year rolling average is based on 2009 through 2013 experience. Since this report relates primarily to Pennsylvania rate regulation practices, no adjustments for expected net salvage were made to either the annual depreciation accrual or the calculated accrued depreciation for individual accounts. Met-Ed, in general, records cost of removal and salvage directly to expense (Account 403, Depreciation Expense) in the year the transactions occur rather than to the depreciation reserve account (Account 108, Accumulated Depreciation).

METROPOLITAN EDISON COMPANY

ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL
DEPRECIATION ACCRUALS BY FUNCTION RELATED TO ELECTRIC PLANT
AT DECEMBER 31, 2011; AT DECEMBER 31, 2012; AND AT DECEMBER 31, 2013
($000)

	2011	2012	2013
Intangible Plant (Amortizable)			
Original Cost (Depreciable)	36,994	36,948	38,039
Book Accrued Depreciation	23,489	26,622	29,670
Book Reserve % of O.C.	63.49%	72.05%	78.00%
Original Cost (Depreciated)	13,505	10,326	8,369
Annual Depreciation Expense	4,049	3,916	3,776
Annual % of O.C.	10.95%	10.60%	9.93%
Transmission Plant			
Original Cost (Depreciable)	349,923	364,613	391,772
Book Accrued Depreciation	139,053	144,200	147,654
Book Reserve % of O.C.	39.74%	39.55%	37.69%
Original Cost (Depreciated)	210,870	220,413	244,118
Annual Depreciation Expense	5,203	5,429	5,919
Annual % of O.C.	1.49%	1.49%	1.51%
Distribution Plant			
Original Cost (Depreciable)	1,798,801	1,915,548	1,962,660
Book Accrued Depreciation	520,957	546,639	563,866
Book Reserve % of O.C.	28.96%	28.54%	28.73%
Original Cost (Depreciated)	1,277,844	1,368,909	1,398,794
Annual Depreciation Expense	35,150	37,200	38,440
Annual % of O.C.	1.95%	1.94%	1.96%
General Plant			
Original Cost (Depreciable)	176,247	176,023	180,375
Book Accrued Depreciation	107,986	109,853	111,849
Book Reserve % of O.C.	61.27%	62.41%	62.01%
Original Cost (Depreciated)	68,261	66,170	68,526
Annual Depreciation Expense	5,300	5,446	5,449
Annual % of O.C.	3.01%	3.09%	3.02%
Total Company (Depreciable)			
Original Cost (Depreciable)	2,361,965	2,493,132	2,572,846
Book Accrued Depreciation	791,486	827,314	853,039
Book Reserve % of O.C.	33.51%	33.18%	33.16%
Original Cost (Depreciated)	1,570,479	1,665,818	1,719,807
Annual Depreciation Expense	49,702	51,992	53,584
Annual % of O.C.	2.10%	2.09%	2.08%
Non-Depreciable Plant	103,852	103,852	105,081
Total Plant In Service	2,465,817	2,596,984	2,677,927

METROPOLITAN EDISON COMPANY

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCURALS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2013

	ACCOUNT AND DESCRIPTION (1)	PROBABLE RETIREMENT YEAR (2)	IOWA SURVIVOR CURVE (3)	GROSS ORIGINAL COST 12/31/2013 (4)	BOOK RESERVE 12/31/2013 (5)	NET ORIGINAL COST 12/31/2013 (6)	AVERAGE SERVICE LIFE (Yrs) (7)	AVERAGE REMAINING LIFE (Yrs) (8)	ANNUAL ACCRUAL (9)	ANNUAL ACCRUAL RATE (%) (10)
	INTANGIBLE PLANT									
303.3	Misc. Intangible Plant - Software - Project Enterprise		7-SQ	$621,985	$621,985	$0	0.00	0.50	$0	0.000000%
303.4	Misc. Intangible Plant - Software - Other		7 SQ	29,368,853	$21,000,197	8,368,656	7.78	1.71	3,775,662	12.856009%
303.5	Misc. Intangible Plant - Software - Proj Evolution		7-SQ	8,047,879	$8,047,879	0	0.00	2.50	0	0.000000%
	TOTAL INTANGIBLES			$38,038,717	$29,670,061	$8,368,656	10.07	2.22	$3,775,662	9.925840%
	TRANSMISSION PLANT									
350.2	Land Rights		80-SQ	$26,933,492	$11,441,502	$15,491,990	66.47	38.23	$405,190	1.504409%
352	Structures		58-R3	6,720,252	2,693,030	4,027,222	54.30	32.54	123,769	1.841726%
353	Station Equipment		54-R1.5	182,774,708	55,374,009	127,400,699	59.52	41.49	3,070,849	1.680128%
354	Towers and Fixtures		65-R3	41,082,524	26,614,852	14,467,672	86.22	30.36	476,491	1.159838%
355	Poles and Fixtures		62-R3	46,196,355	17,969,823	28,226,532	68.69	41.97	672,511	1.455766%
356	Overhead Conductors and Devices		65-R2.5	67,409,524	29,417,786	37,991,737	75.49	42.87	892,938	1.324647%
356.1	Clearing Costs and Rights of Way		80-SQ	18,717,197	3,568,785	15,148,411	81.34	65.83	230,101	1.229358%
358	Underground Conductor & Devices		40-R0.5	1,190,918	61,831	1,129,087	39.77	37.71	29,948	2.514658%
359	Roads and Trails		50-SQ	746,971	512,455	234,516	44.43	13.95	16,812	2.250668%
	TOTAL TRANSMISSION PLANT			$391,771,940	$147,654,073	$244,117,867		41.25	$5,918,608	1.510728%
	DISTRIBUTION PLANT									
360.2	Land Rights		65-SQ	$28,932,190	$14,033,111	$14,899,079	67.87	34.95	$426,319	1.473510%
361	Structures		45-R3	12,964,492	5,846,584	7,117,908	41.16	22.60	314,951	2.429338%
362	Station Equipment		58-R2	204,313,884	70,681,179	133,632,706	64.17	41.97	3,184,132	1.558451%
364	Poles, Towers and Fixtures		65-R0.5	346,857,644	103,388,800	243,468,844	75.90	53.28	4,569,721	1.317463%
365	Overhead Conductors and Devices		55-R0.5	365,129,006	73,936,496	291,192,510	58.62	46.75	6,228,298	1.705780%
365.1	Clearing Costs and Rights of Way		65-SQ	129,000,442	16,431,202	112,569,240	65.84	57.45	1,959,429	1.518932%
366	Underground Conduit		60-R2.5	30,284,874	10,716,043	19,568,832	57.61	37.23	525,668	1.735746%
367	Underground Conductors and Devices		35-R3	201,130,561	65,072,092	136,058,469	35.03	23.70	5,740,986	2.854358%
368	Line Transformers		42-S0	391,129,267	123,368,014	267,761,253	46.77	32.02	8,363,185	2.138215%
369	Overhead Services		42-R0.5	70,598,384	17,674,026	52,924,359	43.83	32.86	1,610,845	2.281703%
369.1	Underground Services		41-R2.5	98,458,792	45,960,843	52,497,949	44.75	23.86	2,200,409	2.234853%
370	Meters		24-O2	65,903,176	11,546,051	54,357,126	23.87	19.69	2,761,271	4.189890%
370	Smart Meters		15-O2	1,218,958	29,853	1,189,105	15.00	14.63	81,264	6.666667%
371	Install. On Cust. Premises - Dusk to Dawn Lights		24-O1	3,819,894	1,828,694	1,991,200	31.42	16.38	121,568	3.182488%
371.21	Install. On Cust. Premises - Meter Socket Devices		25-SQ	412,208	298,985	113,223	31.03	8.52	13,284	3.222582%
371.23	Install. On Cust. Premises - Surge Suppression		10-SQ	276,708	276,708	0	0.00	0.00	0	0.000000%
373	Street Lighting and Signal Systems		34-L0	12,229,687	2,777,690	9,451,997	36.06	27.87	339,160	2.773253%
	TOTAL DISTRIBUTION PLANT			$1,962,660,169	$563,866,368	$1,398,793,801	51.06	36.39	$38,440,490	1.958591%

METROPOLITAN EDISON COMPANY

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCURALS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2013

	ACCOUNT AND DESCRIPTION (1)	PROBABLE RETIREMENT YEAR (2)	IOWA SURVIVOR CURVE (3)	GROSS ORIGINAL COST 12/31/2013 (4)	BOOK RESERVE 12/31/2013 (5)	NET ORIGINAL COST 12/31/2013 (6)	AVERAGE SERVICE LIFE (Yrs) (7)	AVERAGE REMAINING LIFE (Yrs) (8)	ANNUAL ACCRUAL (9)	ANNUAL ACCRUAL RATE (%) (10)
	GENERAL PLANT									
389.2	Land Rights		50-SQ	$18,078	$15,106	$2,972	45.22	7.44	$400	2.211293%
390.1	Structures									
	Misc. Improvements - All Other Locations		40-R1.5	18,513,559	7,727,647	10,785,912	45.12	26.29	$410,302	2.216226%
	Corporate Headquarters - Reading	6-2038	80-S0	50,456,453	25,068,765	25,387,688	44.98	22.63	1,121,754	2.223212%
	Lebanon Service Center	6-2023	80-S0	5,087,650	3,071,867	2,015,784	23.28	9.22	218,577	4.296225%
	Easton Service Center	6-2018	80-S0	4,604,359	3,932,329	672,030	30.39	4.44	151,512	3.290611%
	York Service Center	6-2029	80-S0	7,014,294	3,930,985	3,083,309	35.71	15.70	196,425	2.800358%
	Total Account 390.1			$85,676,315	$43,731,593	$41,944,722	40.83	19.99	$2,098,570	2.449417%
390.2	Land Improvements - Land/Yard									
	Misc. Improvements - All Other Locations		25-R1	$4,340,628	$2,794,277	$1,546,351	26.97	9.61	$160,947	3.707923%
	Corporate Headquarters - Reading	6-2038	80-SQ	3,890,764	1,691,536	2,199,228	42.92	24.26	90,647	2.329789%
	Lebanon Service Center	6-2023	80-SQ	1,009,739	787,684	222,055	43.20	9.50	23,374	2.314868%
	Easton Service Center	6-2018	80-SQ	1,369,572	844,055	525,518	11.73	4.50	116,782	8.526875%
	York Service Center	6-2029	80-SQ	1,855,579	1,131,306	724,273	39.51	15.42	46,965	2.531022%
	Total Account 390.2			$12,466,282	$7,248,857	$5,217,425	28.42	11.89	$438,715	3.519210%
391	Office Furniture and Equip. - Furniture		20-SQ	$16,629,980	$14,460,582	$2,169,398	24.25	3.16	$685,871	4.124306%
391.2	Office Furniture and Equip. - Office Machines		10-SQ	5,920,633	5,920,633	0	0.00	0.00	0	0.000000%
391.3	Office Furniture and Equip. - Personal Computers		4-SQ	2,194,188	2,046,685	147,503	14.88	0.84	147,503	6.722435%
391.4	Office Furniture and Equip. - Information Systems		10-SQ	2,314,955	(1,902)	2,316,857	7.67	7.68	301,710	13.033098%
391.4	Office Furniture and Equip. - Data Proc - Smart Meters		5-SQ	713,151	48,222	664,929	5.00	4.66	142,630	20.000000%
392.3	Transportation - Heavy Trucks		10-L3	268,209	72,066	196,143	10.42	7.62	25,747	9.599641%
392.4	Transportation Equipment - Pole Trailers		25-S1	711,525	454,426	257,099	29.19	10.55	24,375	3.425684%
392.5	Transportation Equipment - Van Trailers		25-S1	87,237	78,891	8,345	126.26	12.08	691	0.792040%
393	Stores Equipment		20-SQ	1,411,422	1,396,541	14,880	113.61	1.20	12,424	0.880237%
394	Tools, Shop and Garage Equipment		25-SQ	11,612,991	6,556,388	5,056,603	23.84	10.38	487,027	4.193808%
395	Laboratory Equipment		20-SQ	3,047,684	3,047,652	32	94,696.97	0.85	32	0.001056%
396	Power Operated Equipment		20-L0.5	751,658	612,058	139,600	58.11	10.79	12,935	1.720815%
397	Communication Equipment		20-R0.5	33,964,326	23,670,778	10,293,549	33.19	10.06	1,023,304	3.012878%
398	Miscellaneous Equipment		20-SQ	2,586,561	2,489,985	96,576	54.41	2.03	47,540	1.837968%
	TOTAL GENERAL PLANT			$180,375,195	$111,848,562	$68,526,633	33.10	12.57	$5,449,473	3.021188%
	TOTAL DEPRECIABLE PLANT			$2,572,846,020	$853,039,063	$1,719,806,956			$53,584,233	2.089725%
	TOTAL NONDEPRECIABLE PLANT			$105,081,468	$95,404,733	$9,676,734				
	TOTAL PLANT IN SERVICE			$2,677,927,487	$948,443,797	$1,729,483,691			$53,584,233	

METROPOLITAN EDISON COMPANY

SCHEDULE 2. SUMMARY OF PLANT IN SERVICE ACTIVITY FOR THE YEAR ENDED DECEMBER 31, 2013

	ACCOUNT AND DESCRIPTION (1)	GROSS ORIGINAL COST 1/1/2013 (2)	ADDITIONS (3)	RETIREMENTS (4)	ADJUSTMENTS (A) (5)	GROSS ORIGINAL COST 12/31/2013 (6)	PERCENT OF ORIGINAL COST RETIRED (7)
	INTANGIBLE PLANT						
303.3	Misc. Intangible Plant - Software - Project Enterprise	$621,985				$621,985	0.00
303.4	Misc. Intangible Plant - Software - Other	28,277,678	$1,091,175			29,368,853	0.00
303.5	Misc. Intangible Plant - Software - Proj Evolution	$8,047,879				$8,047,879	0.00
	TOTAL INTANGIBLES	$36,947,542	$1,091,175	$0	$0	$38,038,717	0.00
	TRANSMISSION PLANT						
350.2	Land Rights	$27,169,639	($236,147)			$26,933,492	0.00
352	Structures	7,333,228	431,515		(1,044,491)	6,720,252	0.00
353	Station Equipment	164,542,836	19,049,921	(1,024,713)	$206,664	182,774,708	0.62
354	Towers and Fixtures	41,961,853	(835,615)	(43,714)		41,082,524	0.10
355	Poles and Fixtures	44,969,810	1,703,268	(476,723)		46,196,355	1.06
356	Overhead Conductors and Devices	64,509,072	3,440,023	(539,571)		67,409,524	0.84
356.1	Clearing Costs and Rights of Way	12,357,013	4,966,770		1,393,414	18,717,197	0.00
358	Underground Conductor & Devices	1,022,596	202,282	(33,960)		1,190,918	3.32
359	Roads and Trails	746,971	0			746,971	0.00
	TOTAL TRANSMISSION PLANT	$364,613,016	$28,722,017	($2,118,681)	$555,587	$391,771,940	0.58
	DISTRIBUTION PLANT						
360.2	Land Rights	$28,696,043	$236,147			$28,932,190	0.00
361	Structures	12,751,972	$214,842	($2,322)		12,964,492	0.02
362	Station Equipment	195,318,146	9,727,797	(1,504,662)	772,603	204,313,884	0.77
364	Poles, Towers and Fixtures	384,863,141	(36,019,634)	(1,985,862)		346,857,644	0.52
365	Overhead Conductors and Devices	320,548,861	50,244,807	(5,664,661)		365,129,006	1.77
365.1	Clearing Costs and Rights of Way	118,923,762	10,425,602		(348,923)	129,000,442	0.00
366	Underground Conduit	30,197,493	87,175	206		30,284,874	0.00
367	Underground Conductors and Devices	188,760,229	13,993,952	(1,623,619)		201,130,561	0.86
368	Line Transformers	386,474,625	8,886,557	(4,231,916)		391,129,267	1.10
369	Overhead Services	68,127,640	2,531,698	(60,954)		70,598,384	0.09
369.1	Underground Services	98,458,792				98,458,792	0.00
370	Meters	66,553,985	4,125,592	(4,832,820)	56,420	65,903,176	7.26
370	Smart Meters	0	1,277,620	(2,243)	(56,420)	1,218,958	#DIV/0!
371	Install. On Cust. Premises - Dusk to Dawn Lights	3,722,598	123,969	(26,673)		3,819,894	0.72
371.2	Install. On Cust. Premises - Meter Socket Devices	412,208			0	412,208	0.00
371.23	Install. On Cust. Premises - Surge Suppression	276,708			0	276,708	0.00
373	Street Lighting and Signal Systems	11,461,900	1,434,443	(666,655)		12,229,687	5.82
	TOTAL DISTRIBUTION PLANT	$1,915,548,104	$67,290,567	($20,602,182)	$423,680	$1,962,660,169	1.08

METROPOLITAN EDISON COMPANY

SCHEDULE 2. SUMMARY OF PLANT IN SERVICE ACTIVITY FOR THE YEAR ENDED DECEMBER 31, 2013

	ACCOUNT AND DESCRIPTION (1)	GROSS ORIGINAL COST 1/1/2013 (2)	ADDITIONS (3)	RETIREMENTS (4)	ADJUSTMENTS (A) (5)	GROSS ORIGINAL COST 12/31/2013 (6)	PERCENT OF ORIGINAL COST RETIRED (7)
	GENERAL PLANT						
389	Land Rights	$18,078				$18,078	0.00
390.1	Structures						
	Misc. Improvements - All Other Locations	$17,547,613	$770,751		$195,195	$18,513,559	0.00
	Corporate Headquarters - Reading	48,853,401	1,603,052			50,456,453	0.00
	Lebanon Service Center	4,777,903	414,613	(104,866)		5,087,650	2.19
	Easton Service Center	5,726,156	(1,043,059)	(78,737)		4,604,359	1.38
	York Service Center	7,011,955	2,339			7,014,294	0.00
	Total Account 390.1	$83,917,027	$1,747,695	($183,603)	$195,195	$85,676,315	0.22
390.2	Land Improvements - Land/Yard						
	Misc. Improvements - All Other Locations	$4,340,628				$4,340,628	0.00
	Corporate Headquarters - Reading	3,890,764				3,890,764	0.00
	Lebanon Service Center	1,009,739				1,009,739	0.00
	Easton Service Center	1,369,572				1,369,572	0.00
	York Service Center	1,855,579				1,855,579	0.00
	Total Account 390.2	$12,466,282	$0	$0	$0	$12,466,282	0.00
391	Office Furniture and Equip. - Furniture	$17,100,405	$51,119	($521,544)		$16,629,980	3.05
391.2	Office Furniture and Equip. - Office Machines	5,920,633				5,920,633	0.00
391.3	Office Furniture and Equip. - Personal Computers	2,365,809	428,903	(460,109)	(140,416)	2,194,188	19.45
391.4	Office Furniture and Equip - Information Systems	350	2,422,715	(351)	(107,758)	2,314,955	100.43
391.4	Office Furniture and Equip - Data Proc - Smart Meter	0	464,977		248,174	713,151	#DIV/0!
392	Transportation Equipment -Heavy Trucks	419,787	(107,927)		(43,650)	268,209	0.00
392.4	Transportation Equipment -Pole Trailers	711,525				711,525	0.00
392.5	Transportation Equipment - Van Trailers	87,237				87,237	0.00
393	Stores Equipment	1,428,705		(17,284)		1,411,422	1.21
394	Tools, Shop and Garage Equipment	10,173,126	1,755,351	(315,486)		11,612,991	3.10
395	Laboratory Equipment	3,130,477		(82,793)		3,047,684	2.64
396	Power Operated Equipment	642,814	108,844			751,658	0.00
397	Communication Equipment	34,970,177	1,062,335	(2,068,186)		33,964,326	5.91
398	Miscellaneous Equipment	2,671,048	11,519	(96,006)		2,586,561	3.59
	TOTAL GENERAL PLANT	$176,023,480	$7,945,531	($3,745,361)	$151,545	$180,375,195	2.13
	TOTAL DEPRECIABLE PLANT	$2,493,132,142	$105,049,290	($26,466,224)	$1,130,812	$2,572,846,020	1.06
	NONDEPRECIABLE PLANT AND ASSET RETIREMENT COSTS						
301	Organization	$123,507				$123,507	
302	Franchise and Consents	165,169				165,169	
326	Asset Retirement Costs TMI #2	95,321,155				95,321,155	
350.1	Land	3,429,373				3,429,373	
359	Asset Retirement Costs Transmission Subs	4,666				4,666	
360.1	Land	3,080,352	$124,524			3,204,876	
374	Asset Retirement Costs Distribution Subs	37,210				37,210	
389.1	Land	1,567,850	1,104,958			2,672,808	
39030	Building Leaseholds	16,754				16,754	
399	Asset Retirement Costs General Buildings	105,951				105,951	
	TOTAL NONDEPRECIABLE PLANT	$103,851,986	$1,229,482	$0	$0	$105,081,468	
	TOTAL PLANT IN SERVICE	$2,596,984,127	$106,278,772	($26,466,224)	$1,130,812	$2,677,927,487	

METROPOLITAN EDISON COMPANY

SCHEDULE 3. SUMMARY OF BOOK RESERVE ACTIVITY FOR THE YEAR ENDED DECEMBER 31, 2013

	ACCOUNT AND DESCRIPTION (1)	BOOK RESERVE 1/1/2013 (2)	ACCRUALS (3)	RETIREMENTS (4)	GROSS SALVAGE (A) (5)	COST OF REMOVAL (A) (6)	TRANSFERS (7)	ADJUSTMENTS (8)	BOOK RESERVE 12/31/2013 (9)	BOOK RESERVE AS A PERCENT OF ORIGINAL COST (10)
	INTANGIBLE PLANT									
303.3	Project Enterprise	($621,985)							($621,985)	
303.4	Misc. Intangible Plant - Software - Other	(17,952,598)	($3,047,599)						(21,000,197)	
303.5	Software Evolution	(8,047,879)							(8,047,879)	
	TOTAL INTANGIBLES	($26,622,462)	($3,047,599)	$0	$0	$0	$0	$0	($29,670,061)	78.00
	TRANSMISSION PLANT									
350.2	Land Rights	($11,035,441)	($406,061)						($11,441,502)	42.48
352	Structures	(2,631,288)	(128,649)				66,907		(2,693,030)	40.07
353	Station Equipment	(53,610,958)	(2,821,080)	1,024,713	(56)	46,569	($13,198)		(55,374,009)	30.30
354	Towers and Fixtures	(26,166,835)	(491,730)	43,714					(26,614,852)	64.78
355	Poles and Fixtures	(17,799,863)	(646,682)	476,723					(17,969,823)	38.90
356	Overhead Conductors and Devices	(29,106,937)	(1,763,836)	539,571		847,681	65,734		(29,417,786)	43.64
356.1	Clearing Costs and Rights of Way	(3,283,574)	(193,832)				(91,379)		(3,568,785)	19.07
358	Underground Conductor & Devices	(69,006)	(26,785)	33,960					(61,831)	5.19
359	Roads and Trails	(495,639)	(16,816)						(512,455)	68.60
	TOTAL TRANSMISSION PLANT	($144,199,541)	($6,495,471)	$2,118,681	($56)	$894,250	$28,064	$0	($147,654,073)	37.69
	DISTRIBUTION PLANT									
360.2	Land Rights	($13,608,983)	($424,128)						($14,033,111)	48.50
361	Structures	(5,532,139)	(316,767)	$2,322					(5,846,584)	45.10
362	Station Equipment	(68,910,966)	(3,804,297)	1,504,662	(9,862)	922,750	($383,465)		(70,681,179)	34.59
364	Poles, Towers and Fixtures	(100,588,313)	(4,786,349)	1,985,862					(103,388,800)	29.81
365	Overhead Conductors and Devices	(73,760,314)	(6,650,851)	5,664,661	(577)	1,322,164	(511,581)		(73,936,496)	20.25
365.1	Clearing Costs and Rights of Way	(14,565,026)	(1,890,648)				24,472		(16,431,202)	12.74
366	Underground Conduit	(10,187,435)	(528,402)	(205)					(10,716,043)	35.38
367	Underground Conductors and Devices	(61,146,542)	(5,549,169)	1,623,619					(65,072,092)	32.35
368	Line Transformers	(119,308,500)	(8,594,280)	4,231,916	(457,395.66)	861,112	(136,121)	35,255	(123,368,014)	31.54
369	Overhead Services	(16,135,399)	(1,799,139)	60,954		221,294	(21,736)		(17,674,026)	25.03
369.1	Underground Services	(43,740,985)	(2,219,858)						(45,960,843)	46.68
370	Meters	(13,727,848)	(2,649,743)	4,832,820			(1,279)		(11,546,051)	17.52
370	Smart Meters	0	(33,375)	2,243			1,279		(29,853)	2.45
371	Install. On Cust. Premises - Dusk to Dawn Lights	(1,733,319)	(122,047)	26,672			0		(1,828,694)	47.87
371.2	Install. On Cust. Premises - Meter Socket Devices	(285,701)	(13,284)						(298,985)	72.53
371.23	Install. On Cust. Premises - Surge Suppression	(276,708)							(276,708)	100.00
373	Street Lighting and Signal Systems	(3,131,073)	66,828	666,654		(377,183)	(2,917)		(2,777,690)	22.71
	TOTAL DISTRIBUTION PLANT	($546,639,251)	($39,315,509)	$20,602,181	($467,835)	$2,950,138	($1,031,347)	$35,255	($563,866,368)	28.73

METROPOLITAN EDISON COMPANY

SCHEDULE 3. SUMMARY OF BOOK RESERVE ACTIVITY FOR THE YEAR ENDED DECEMBER 31, 2013

	ACCOUNT AND DESCRIPTION (1)	BOOK RESERVE 1/1/2013 (2)	ACCRUALS (3)	RETIREMENTS (4)	GROSS SALVAGE (A) (5)	COST OF REMOVAL (A) (6)	TRANSFERS (7)	ADJUSTMENTS (8)	BOOK RESERVE 12/31/2013 (9)	BOOK RESERVE AS A PERCENT OF ORIGINAL COST (10)
	GENERAL PLANT									
389	Land Rights	($14,699)	($407)						($15,106)	83.56
390.1	Structures									
	Misc. Improvements - All Other Locations	($7,334,126)	($498,729)			$118,631	($13,423)		($7,727,647)	41.74
	Corporate Headquarters - Reading	(23,984,249)	(1,084,516)						(25,068,765)	49.68
	Lebanon Service Center	(2,990,485)	(186,248)	104,866					(3,071,867)	60.38
	Easton Service Center	(3,671,401)	(339,664)	78,737					(3,932,329)	85.40
	York Service Center	(3,721,294)	(209,691)						(3,930,985)	56.04
	Total Account 390.1	($41,701,556)	($2,318,848)	$183,603	$0	$118,631	($13,423)	$0	($43,731,593)	51.04
390.2	Land Improvements - Land/Yard									
	Misc. Improvements - All Other Locations	($2,624,417)	($169,861)						($2,794,277)	64.37
	Corporate Headquarters - Reading	(1,600,889)	(90,647)						(1,691,536)	43.48
	Lebanon Service Center	(764,310)	(23,374)						(787,684)	78.01
	Easton Service Center	(727,273)	(116,782)						(844,055)	61.63
	York Service Center	(1,084,537)	(46,769)						(1,131,306)	60.97
	Total Account 390.2	($6,801,425)	($447,432)	$0	$0	$0	$0	$0	($7,248,857)	58.15
391	Office Furniture and Equip. - Furniture	($14,228,375)	($753,751)	$521,544					($14,460,582)	86.95
391.2	Office Furniture and Equip. - Office Machines	(5,920,633)							(5,920,633)	100.00
391.3	Office Furniture and Equip. - Personal Computers	(1,860,218)	(659,074)	460,109			12,498		(2,046,685)	93.28
391.4	Office Furniture and Equip. - Information Systems	(225)	262	351			1,513		1,902	-0.08
391.4	Office Furniture and Equip. - Data Proc Smart Meters	0	(34,210)				(14,012)		(48,222)	17.98
392	Transportation Equipment - Heavy Trucks	(40,187)	(38,884)				7,004		(72,066)	26.87
392.4	Transportation Equipment - Pole Trailers	(428,872)	(25,554)						(454,426)	63.87
392.5	Transportation Equipment - Van Trailers	(78,174)	(717)						(78,891)	90.43
393	Stores Equipment	(1,382,946)	(30,879)	17,284					(1,396,541)	98.95
394	Tools, Shop and Garage Equipment	(6,379,610)	(492,264)	315,486					(6,556,388)	56.46
395	Laboratory Equipment	(3,129,864)	(581)	82,793					(3,047,652)	100.00
396	Power Operated Equipment	(608,161)	(3,897)						(612,058)	81.43
397	Communication Equipment	(24,755,167)	(987,927)	2,068,186		$4,130			(23,670,778)	69.69
398	Miscellaneous Equipment	(2,523,068)	(62,923)	96,006					(2,489,985)	96.27
	TOTAL GENERAL PLANT	($109,853,181)	($5,857,085)	$3,745,361	$0	$122,762	($6,418)	$0	($111,848,562)	62.01
	TOTAL DEPRECIABLE PLANT	($827,314,434)	($54,715,664)	$26,466,222	($467,891)	$3,967,150	($1,009,702)	$35,255	($853,039,063)	33.16
	NONDEPRECIABLE PLANT AND ASSET RETIREMENT COSTS									
326	Asset Retirement Costs TMI # 2	($95,321,155)							($95,321,155)	
350.1	Land	($7,848)	$1,500			(1,500)			($7,848)	
359.1	Asset Retirement Costs Transmission Subs	(2,486)	($104)						(2,589)	
374	Asset Retirement Costs Distribution Subs	(20,482)	(759)						(21,241)	
360	Land Sale Adjustment	(0)							(0)	
39030	Building Leaseholds	(3,246)	(838)						(4,084)	
399	Asset Retirement Costs General Buildings	(45,950)	(1,866)						(47,816)	
	TOTAL NONDEPRECIABLE PLANT	($95,401,167)	($2,067)	$0	$0	($1,500)	$0	$0	($95,404,733)	
	TOTAL BOOK RESERVE	($922,715,601)	($54,717,730)	$26,466,222	($467,891)	$3,965,650	($1,009,702)	$35,255	($948,443,797)	

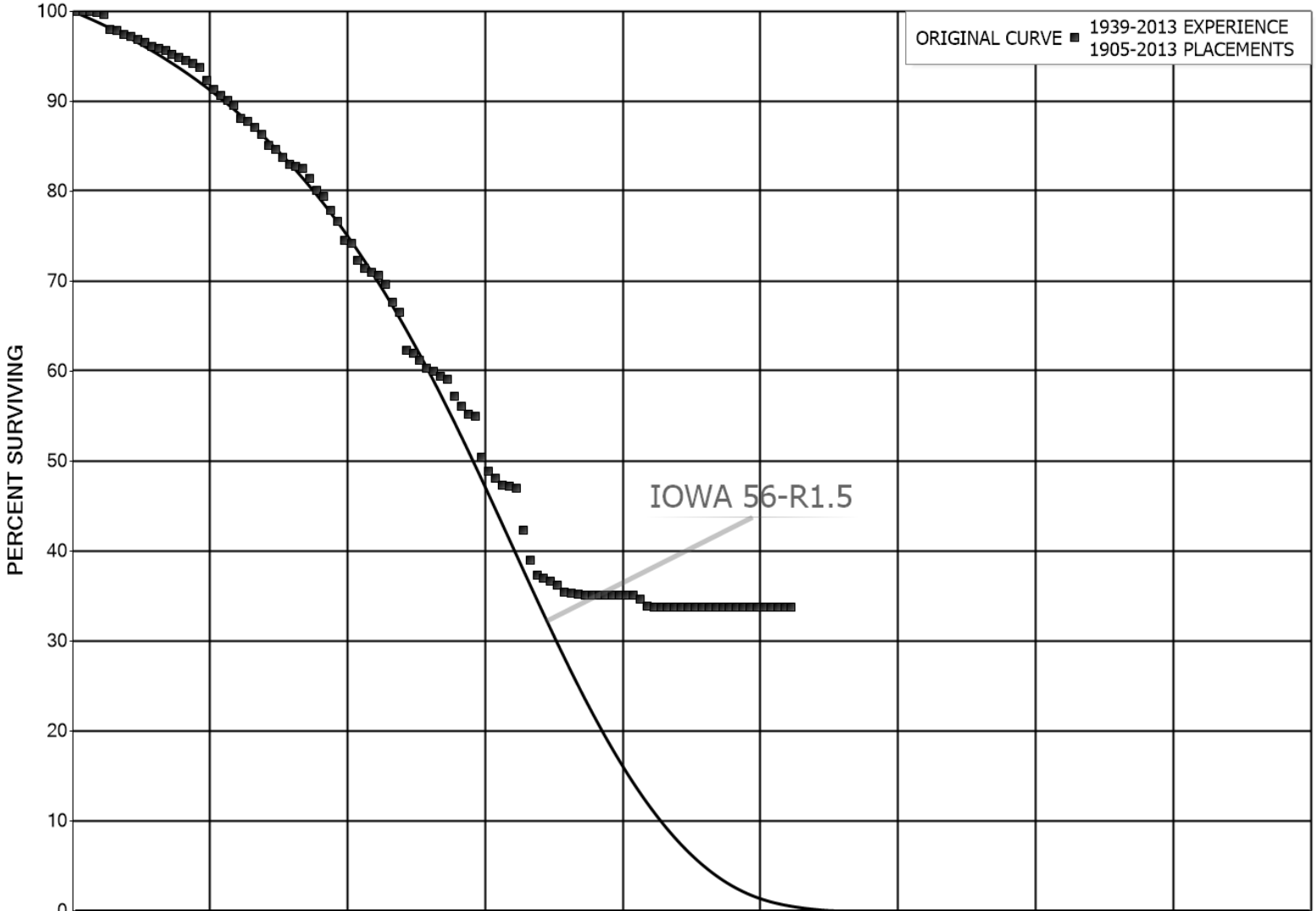
(A) Cost of Removal and Salvage amounts are expensed as incurred and as such are not included in this summarization.

METROPOLITAN EDISON COMPANY

SCHEDULE 4. EXPERIENCED COST OF REMOVAL AND SALVAGE AMOUNTS FOR THE YEARS 2009-2013 RECORDED TO ACCOUNT 403, DEPRECIATION EXPENSE

	COST OF REMOVAL 403 (1)	SALVAGE 403 (2)	NET SALVAGE (3)=(1)+(2)
2009	$4,955,233	($1,175,586)	$3,779,647
2010	$4,369,607	($696,543)	$3,673,065
2011	$19,958,473	($6,484,916)	$13,473,557
2012	$23,007,411	($498,217)	$22,509,194
2013	$4,912,392	($467,891)	$4,444,501
Total	$57,203,117	($9,323,153)	$47,879,964
5-Year Average	$11,440,623	($1,864,631)	$9,575,993

METROPOLITAN EDISON COMPANY
ACCOUNT 353 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



METROPOLITAN EDISON COMPANY

ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1905-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	229,958,021	16,736	0.0001	0.9999	100.00
0.5	212,512,592	80,270	0.0004	0.9996	99.99
1.5	201,331,267	51,183	0.0003	0.9997	99.95
2.5	189,513,646	140,361	0.0007	0.9993	99.93
3.5	183,618,669	449,655	0.0024	0.9976	99.86
4.5	173,851,003	2,823,301	0.0162	0.9838	99.61
5.5	148,202,373	157,089	0.0011	0.9989	97.99
6.5	146,342,820	785,145	0.0054	0.9946	97.89
7.5	128,851,813	311,876	0.0024	0.9976	97.36
8.5	125,748,187	373,677	0.0030	0.9970	97.13
9.5	122,005,802	471,637	0.0039	0.9961	96.84
10.5	119,968,722	442,938	0.0037	0.9963	96.47
11.5	117,937,198	295,890	0.0025	0.9975	96.11
12.5	115,392,244	298,565	0.0026	0.9974	95.87
13.5	110,707,059	483,507	0.0044	0.9956	95.62
14.5	109,460,105	407,458	0.0037	0.9963	95.20
15.5	106,737,439	416,829	0.0039	0.9961	94.85
16.5	103,004,926	296,769	0.0029	0.9971	94.48
17.5	100,365,769	551,645	0.0055	0.9945	94.21
18.5	97,353,903	1,452,843	0.0149	0.9851	93.69
19.5	90,398,151	1,020,622	0.0113	0.9887	92.29
20.5	87,817,470	600,334	0.0068	0.9932	91.25
21.5	81,401,101	498,451	0.0061	0.9939	90.62
22.5	77,211,739	488,281	0.0063	0.9937	90.07
23.5	75,670,947	1,238,807	0.0164	0.9836	89.50
24.5	72,533,496	226,039	0.0031	0.9969	88.03
25.5	71,131,861	528,658	0.0074	0.9926	87.76
26.5	68,583,095	634,762	0.0093	0.9907	87.11
27.5	61,243,908	861,429	0.0141	0.9859	86.30
28.5	56,210,385	348,174	0.0062	0.9938	85.09

METROPOLITAN EDISON COMPANY

ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
29.5	54,214,275	522,021	0.0096	0.9904	84.56
30.5	51,403,868	464,608	0.0090	0.9910	83.75
31.5	50,575,354	153,382	0.0030	0.9970	82.99
32.5	49,940,950	119,404	0.0024	0.9976	82.74
33.5	49,574,625	707,762	0.0143	0.9857	82.54
34.5	48,665,520	766,416	0.0157	0.9843	81.36
35.5	47,506,217	388,910	0.0082	0.9918	80.08
36.5	46,222,147	910,067	0.0197	0.9803	79.42
37.5	33,960,887	531,204	0.0156	0.9844	77.86
38.5	31,753,263	906,530	0.0285	0.9715	76.64
39.5	30,240,804	119,991	0.0040	0.9960	74.45
40.5	27,606,763	714,747	0.0259	0.9741	74.16
41.5	24,586,641	297,338	0.0121	0.9879	72.24
42.5	20,973,636	128,746	0.0061	0.9939	71.37
43.5	16,466,236	67,753	0.0041	0.9959	70.93
44.5	14,140,187	202,893	0.0143	0.9857	70.64
45.5	12,186,004	348,316	0.0286	0.9714	69.62
46.5	11,445,021	191,550	0.0167	0.9833	67.63
47.5	10,474,692	661,634	0.0632	0.9368	66.50
48.5	9,359,859	46,799	0.0050	0.9950	62.30
49.5	9,036,250	113,606	0.0126	0.9874	61.99
50.5	7,860,235	117,543	0.0150	0.9850	61.21
51.5	6,590,126	39,746	0.0060	0.9940	60.29
52.5	6,395,076	57,161	0.0089	0.9911	59.93
53.5	6,273,557	31,506	0.0050	0.9950	59.39
54.5	6,102,197	202,446	0.0332	0.9668	59.10
55.5	5,505,458	107,405	0.0195	0.9805	57.14
56.5	5,284,186	77,737	0.0147	0.9853	56.02
57.5	5,175,139	18,965	0.0037	0.9963	55.20
58.5	4,803,211	399,993	0.0833	0.9167	54.99

METROPOLITAN EDISON COMPANY

ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
59.5	1,930,806	60,615	0.0314	0.9686	50.41
60.5	1,771,081	27,430	0.0155	0.9845	48.83
61.5	1,219,040	20,309	0.0167	0.9833	48.08
62.5	1,015,399	2,664	0.0026	0.9974	47.27
63.5	985,858	2,953	0.0030	0.9970	47.15
64.5	966,200	96,120	0.0995	0.9005	47.01
65.5	651,573	51,620	0.0792	0.9208	42.33
66.5	510,800	21,693	0.0425	0.9575	38.98
67.5	480,980	5,052	0.0105	0.9895	37.32
68.5	459,794	4,396	0.0096	0.9904	36.93
69.5	431,756	5,332	0.0123	0.9877	36.58
70.5	249,976	5,100	0.0204	0.9796	36.13
71.5	226,342	365	0.0016	0.9984	35.39
72.5	114,277	673	0.0059	0.9941	35.33
73.5	98,918	91	0.0009	0.9991	35.12
74.5	97,438		0.0000	1.0000	35.09
75.5	97,199		0.0000	1.0000	35.09
76.5	97,189		0.0000	1.0000	35.09
77.5	96,769	115	0.0012	0.9988	35.09
78.5	96,057		0.0000	1.0000	35.05
79.5	96,057	54	0.0006	0.9994	35.05
80.5	96,003		0.0000	1.0000	35.03
81.5	95,969	1,156	0.0120	0.9880	35.03
82.5	92,814	2,017	0.0217	0.9783	34.61
83.5	82,975	293	0.0035	0.9965	33.86
84.5	69,679		0.0000	1.0000	33.74
85.5	68,623		0.0000	1.0000	33.74
86.5	53,277		0.0000	1.0000	33.74
87.5	39,864		0.0000	1.0000	33.74
88.5	8,321		0.0000	1.0000	33.74

METROPOLITAN EDISON COMPANY

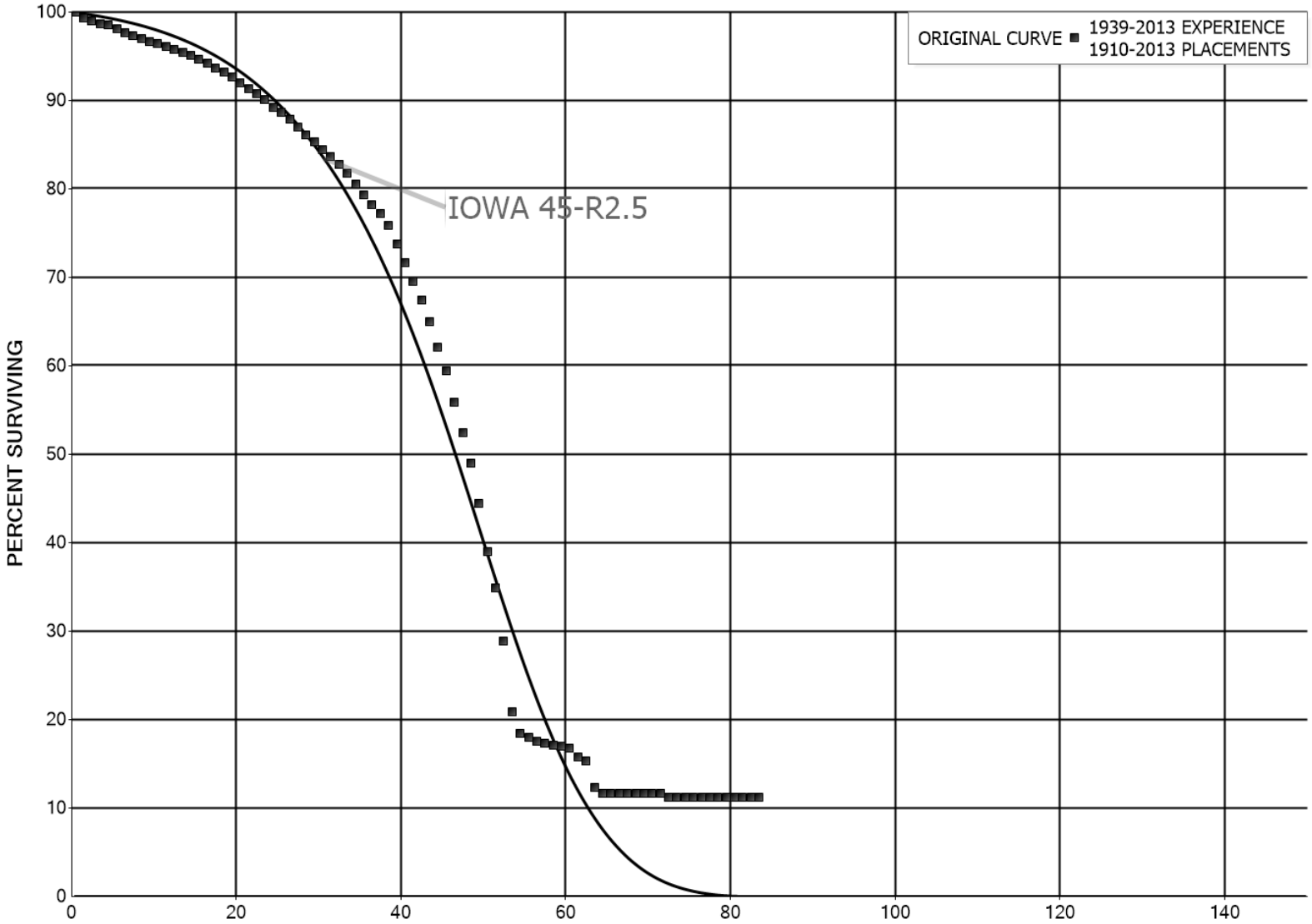
ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
89.5	8,304		0.0000	1.0000	33.74
90.5	2,978		0.0000	1.0000	33.74
91.5	2,848		0.0000	1.0000	33.74
92.5	2,773		0.0000	1.0000	33.74
93.5	312		0.0000	1.0000	33.74
94.5	49		0.0000	1.0000	33.74
95.5	49		0.0000	1.0000	33.74
96.5	49		0.0000	1.0000	33.74
97.5	49		0.0000	1.0000	33.74
98.5	49		0.0000	1.0000	33.74
99.5	49		0.0000	1.0000	33.74
100.5	49		0.0000	1.0000	33.74
101.5	49		0.0000	1.0000	33.74
102.5	49		0.0000	1.0000	33.74
103.5	49		0.0000	1.0000	33.74
104.5					33.74

METROPOLITAN EDISON COMPANY
ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



METROPOLITAN EDISON COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	205,016,324	195,304	0.0010	0.9990	100.00
0.5	192,977,926	1,193,713	0.0062	0.9938	99.90
1.5	178,851,546	681,225	0.0038	0.9962	99.29
2.5	167,690,619	439,734	0.0026	0.9974	98.91
3.5	160,133,209	307,148	0.0019	0.9981	98.65
4.5	146,490,409	555,111	0.0038	0.9962	98.46
5.5	143,260,951	694,780	0.0048	0.9952	98.09
6.5	137,793,116	443,918	0.0032	0.9968	97.61
7.5	124,504,003	422,424	0.0034	0.9966	97.30
8.5	116,292,616	378,941	0.0033	0.9967	96.97
9.5	108,637,376	333,424	0.0031	0.9969	96.65
10.5	103,076,274	361,375	0.0035	0.9965	96.35
11.5	98,941,153	304,678	0.0031	0.9969	96.02
12.5	94,197,532	345,863	0.0037	0.9963	95.72
13.5	89,307,893	318,868	0.0036	0.9964	95.37
14.5	84,408,707	362,879	0.0043	0.9957	95.03
15.5	76,189,011	373,908	0.0049	0.9951	94.62
16.5	71,109,032	383,605	0.0054	0.9946	94.16
17.5	68,262,876	328,793	0.0048	0.9952	93.65
18.5	63,339,069	389,148	0.0061	0.9939	93.20
19.5	57,756,321	394,526	0.0068	0.9932	92.62
20.5	53,276,499	396,957	0.0075	0.9925	91.99
21.5	48,068,716	298,886	0.0062	0.9938	91.31
22.5	40,909,493	287,558	0.0070	0.9930	90.74
23.5	34,502,079	348,246	0.0101	0.9899	90.10
24.5	29,572,302	205,874	0.0070	0.9930	89.19
25.5	25,518,266	205,951	0.0081	0.9919	88.57
26.5	21,877,033	226,679	0.0104	0.9896	87.86
27.5	18,737,346	189,642	0.0101	0.9899	86.94
28.5	16,236,958	150,625	0.0093	0.9907	86.06

METROPOLITAN EDISON COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
29.5	14,882,788	153,620	0.0103	0.9897	85.27
30.5	13,789,435	120,454	0.0087	0.9913	84.39
31.5	12,873,055	144,524	0.0112	0.9888	83.65
32.5	12,001,339	145,023	0.0121	0.9879	82.71
33.5	11,056,784	159,870	0.0145	0.9855	81.71
34.5	9,979,775	156,232	0.0157	0.9843	80.53
35.5	9,062,487	118,771	0.0131	0.9869	79.27
36.5	8,171,443	112,542	0.0138	0.9862	78.23
37.5	7,463,253	126,553	0.0170	0.9830	77.15
38.5	6,828,882	195,586	0.0286	0.9714	75.84
39.5	5,724,962	158,376	0.0277	0.9723	73.67
40.5	4,742,999	144,013	0.0304	0.9696	71.63
41.5	4,002,160	118,347	0.0296	0.9704	69.46
42.5	3,263,232	117,021	0.0359	0.9641	67.40
43.5	2,849,663	128,322	0.0450	0.9550	64.99
44.5	2,503,187	109,396	0.0437	0.9563	62.06
45.5	2,152,292	126,509	0.0588	0.9412	59.35
46.5	1,804,190	110,348	0.0612	0.9388	55.86
47.5	1,600,435	107,787	0.0673	0.9327	52.44
48.5	1,389,741	128,769	0.0927	0.9073	48.91
49.5	1,233,864	150,636	0.1221	0.8779	44.38
50.5	1,082,389	113,705	0.1051	0.8949	38.96
51.5	968,378	168,301	0.1738	0.8262	34.87
52.5	800,077	220,645	0.2758	0.7242	28.81
53.5	579,128	67,460	0.1165	0.8835	20.86
54.5	507,611	13,611	0.0268	0.9732	18.43
55.5	619,497	16,823	0.0272	0.9728	17.94
56.5	765,738	7,438	0.0097	0.9903	17.45
57.5	733,192	8,394	0.0114	0.9886	17.28
58.5	714,091	4,510	0.0063	0.9937	17.08

METROPOLITAN EDISON COMPANY

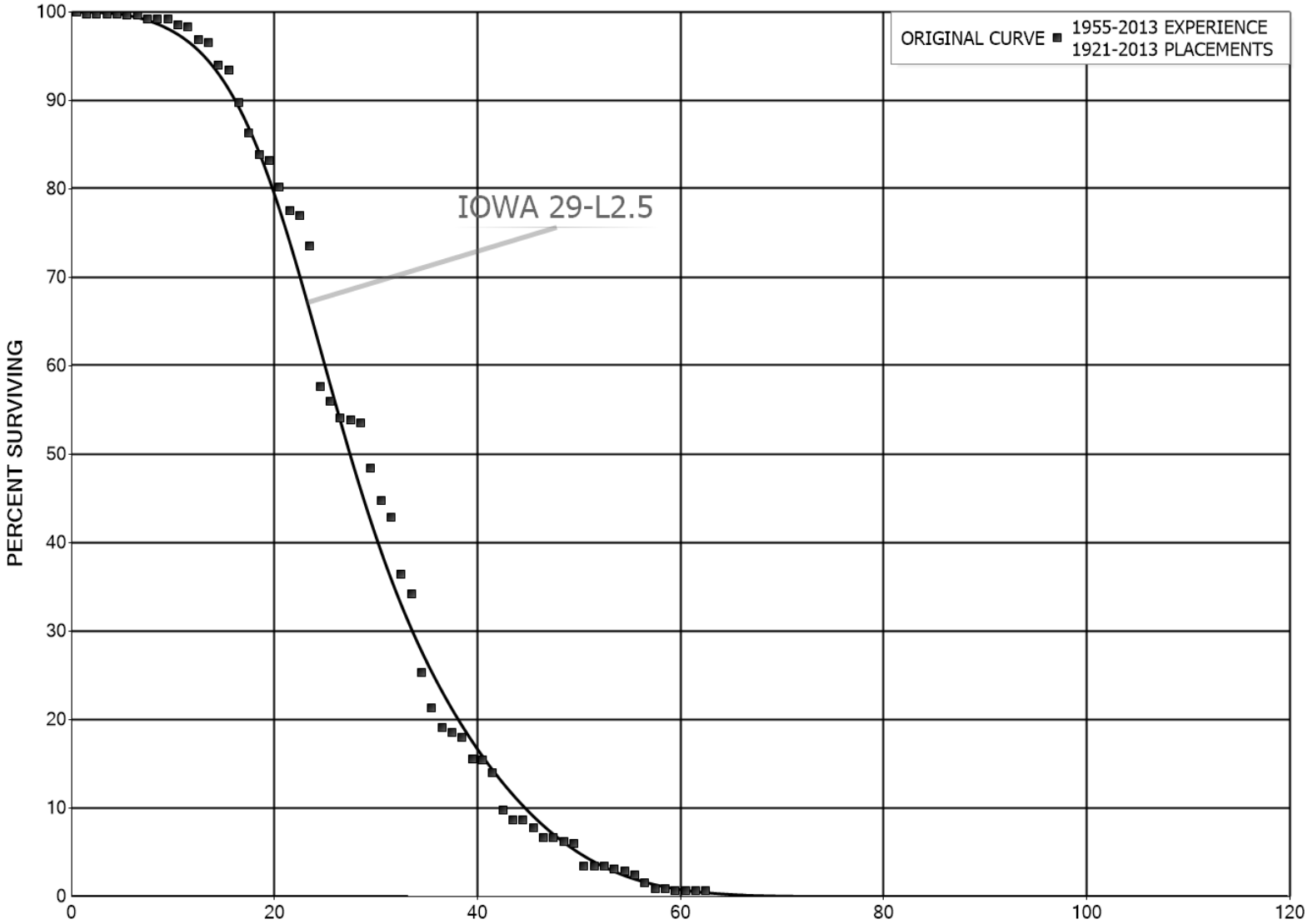
ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2013 EXPERIENCE BAND 1939-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
59.5	707,296	9,210	0.0130	0.9870	16.98
60.5	690,463	42,540	0.0616	0.9384	16.76
61.5	528,172	15,760	0.0298	0.9702	15.72
62.5	442,870	85,038	0.1920	0.8080	15.25
63.5	296,105	17,386	0.0587	0.9413	12.33
64.5	219,858	317	0.0014	0.9986	11.60
65.5	204,848	215	0.0010	0.9990	11.58
66.5	191,822	4	0.0000	1.0000	11.57
67.5	165,050	95	0.0006	0.9994	11.57
68.5	16,994		0.0000	1.0000	11.57
69.5	10,210		0.0000	1.0000	11.57
70.5	6,584		0.0000	1.0000	11.57
71.5	6,584	235	0.0357	0.9643	11.57
72.5	6,584		0.0000	1.0000	11.15
73.5	6,572		0.0000	1.0000	11.15
74.5	6,572		0.0000	1.0000	11.15
75.5	6,572		0.0000	1.0000	11.15
76.5	6,090		0.0000	1.0000	11.15
77.5	6,090		0.0000	1.0000	11.15
78.5	6,090		0.0000	1.0000	11.15
79.5	6,090		0.0000	1.0000	11.15
80.5	6,090		0.0000	1.0000	11.15
81.5	6,090		0.0000	1.0000	11.15
82.5	6,090		0.0000	1.0000	11.15
83.5					11.15

METROPOLITAN EDISON COMPANY
ACCOUNT 392.40 TRANSPORTATION EQUIPMENT - POLE TRAILERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



METROPOLITAN EDISON COMPANY

ACCOUNT 392.40 TRANSPORTATION EQUIPMENT - POLE TRAILERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1921-2013 EXPERIENCE BAND 1955-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,210,415		0.0000	1.0000	100.00
0.5	1,113,404	2,700	0.0024	0.9976	100.00
1.5	1,110,707		0.0000	1.0000	99.76
2.5	960,416	223	0.0002	0.9998	99.76
3.5	959,906		0.0000	1.0000	99.73
4.5	950,689	1,123	0.0012	0.9988	99.73
5.5	1,161,671		0.0000	1.0000	99.62
6.5	1,156,701	5,318	0.0046	0.9954	99.62
7.5	1,159,378		0.0000	1.0000	99.16
8.5	1,154,804		0.0000	1.0000	99.16
9.5	1,108,837	7,297	0.0066	0.9934	99.16
10.5	1,140,222	2,779	0.0024	0.9976	98.51
11.5	1,078,690	15,447	0.0143	0.9857	98.27
12.5	1,061,366	3,575	0.0034	0.9966	96.86
13.5	1,048,980	28,402	0.0271	0.9729	96.53
14.5	929,128	4,689	0.0050	0.9950	93.92
15.5	875,121	34,628	0.0396	0.9604	93.44
16.5	621,665	24,006	0.0386	0.9614	89.75
17.5	595,106	16,632	0.0279	0.9721	86.28
18.5	585,884	5,035	0.0086	0.9914	83.87
19.5	507,396	18,231	0.0359	0.9641	83.15
20.5	468,853	15,324	0.0327	0.9673	80.16
21.5	369,994	2,934	0.0079	0.9921	77.54
22.5	367,059	16,290	0.0444	0.9556	76.93
23.5	351,574	76,094	0.2164	0.7836	73.51
24.5	275,480	8,145	0.0296	0.9704	57.60
25.5	263,461	8,877	0.0337	0.9663	55.90
26.5	234,229	812	0.0035	0.9965	54.02
27.5	235,821	1,298	0.0055	0.9945	53.83
28.5	230,922	22,217	0.0962	0.9038	53.53

METROPOLITAN EDISON COMPANY

ACCOUNT 392.40 TRANSPORTATION EQUIPMENT - POLE TRAILERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1921-2013 EXPERIENCE BAND 1955-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
29.5	196,617	14,826	0.0754	0.9246	48.38
30.5	165,855	6,959	0.0420	0.9580	44.73
31.5	153,517	23,161	0.1509	0.8491	42.86
32.5	131,354	7,865	0.0599	0.9401	36.39
33.5	123,489	32,275	0.2614	0.7386	34.21
34.5	86,891	13,828	0.1591	0.8409	25.27
35.5	73,063	7,540	0.1032	0.8968	21.25
36.5	65,307	1,751	0.0268	0.9732	19.06
37.5	63,683	2,094	0.0329	0.9671	18.54
38.5	59,050	7,872	0.1333	0.8667	17.94
39.5	51,179	418	0.0082	0.9918	15.54
40.5	50,760	4,685	0.0923	0.9077	15.42
41.5	41,035	12,450	0.3034	0.6966	13.99
42.5	25,541	2,976	0.1165	0.8835	9.75
43.5	15,629		0.0000	1.0000	8.61
44.5	15,629	1,552	0.0993	0.9007	8.61
45.5	11,019	1,631	0.1480	0.8520	7.76
46.5	9,388		0.0000	1.0000	6.61
47.5	9,388	591	0.0630	0.9370	6.61
48.5	8,796	403	0.0458	0.9542	6.19
49.5	8,393	3,511	0.4183	0.5817	5.91
50.5	4,883		0.0000	1.0000	3.44
51.5	5,229		0.0000	1.0000	3.44
52.5	5,229	593	0.1134	0.8866	3.44
53.5	4,636	381	0.0821	0.9179	3.05
54.5	4,256	592	0.1391	0.8609	2.80
55.5	3,664	1,448	0.3951	0.6049	2.41
56.5	2,216	994	0.4486	0.5514	1.46
57.5	1,222		0.0000	1.0000	0.80
58.5	1,222	347	0.2837	0.7163	0.80
59.5	875		0.0000	1.0000	0.58
60.5	875		0.0000	1.0000	0.58
61.5	875		0.0000	1.0000	0.58
62.5					0.58

Remaining Life Depreciation Accrual

Account: MTED-101/6-303
Scenario: Met Ed 2014 ADR Intangible
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$38,038,716.98	1.71	$4,890,260.79	12.856009%	58.435449%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($6,556,772.60)	0.50	($468,340.90)	7.142857%	
Total:	$38,038,716.98 *		$4,421,919.89	11.624787%	52.839079%
Average:	$34,760,330.68		$4,421,919.89	12.721168%	86.870079%
Grand Total:	$38,038,716.98 *		$4,421,919.89	11.624787%	52.839079%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED-101/6-303
Scenario: Met Ed 2014 ADR Intangible
Dispersion: 7 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$38,038,716.98	$29,670,062.59	0.7800	$8,368,654.39	0.2200
Computed	$38,038,716.98	$28,739,390.46	0.7555	$9,299,326.52	0.2445
Difference		$930,672.13	0.0245	($930,672.13)	-0.0245

Generation Arrangement Report

Account: MTED-101/6-303
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$2,426,308.05	7.00	6.50	0.9286	1.0000	$2,253,000.33	$346,615.44
2012	1.50	$1,965,581.28	7.00	5.50	0.7857	1.0000	$1,544,385.29	$280,797.33
2011	2.50	$5,239,256.68	7.00	4.50	0.6429	1.0000	$3,368,093.58	$748,465.24
2010	3.50	$1,296,663.99	7.00	3.50	0.5000	1.0000	$648,332.00	$185,237.71
2009	4.50	$2,395,595.32	7.00	2.50	0.3571	1.0000	$855,569.76	$342,227.90
2008	5.50	$754,155.12	7.00	1.50	0.2143	1.0000	$161,604.67	$107,736.45
2007	6.50	$6,556,772.60	7.00	0.50	0.0714	1.0000	$468,340.90	$936,681.80
2006	7.50	$1,212,256.65	7.00	0.00	0.0000	0.0000	$0.00	$0.00
2005	8.50	$794,414.65	7.00	0.00	0.0000	0.0000	$0.00	$0.00
2004	9.50	$3,919,197.54	7.00	0.00	0.0000	0.0000	$0.00	$0.00
2003	10.50	$8,906,879.41	7.00	0.00	0.0000	0.0000	$0.00	$0.00
2002	11.50	$126,412.52	7.00	0.00	0.0000	0.0000	$0.00	$0.00
2001	12.50	$575,318.25	7.00	0.00	0.0000	0.0000	$0.00	$0.00
2000	13.50	$58,628.45	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1997	16.50	$32,387.07	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1994	19.50	$1,778,889.40	7.00	0.00	0.0000	0.0000	$0.00	$0.00
		$38,038,716.98	7.00	1.71	0.2445	1.0000	$9,299,326.52	$2,947,761.86

Remaining Life Depreciation Accrual

Account: MTED-101/6-301
Scenario: Met Ed 2014 ADR Intangible
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$123,507.40	0.00	$123,507.40	100.000000%	100.000000%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$123,507.40 *		$123,507.40	100.000000%	100.000000%
Average:	$123,507.40		$123,507.40	100.000000%	100.000000%
Grand Total:	$123,507.40 *		$123,507.40	100.000000%	100.000000%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED-101/6-301
Scenario: Met Ed 2014 ADR Intangible
Dispersion: 7 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$123,507.40	$0.00	0.0000	$123,507.40	1.0000
Computed	$123,507.40	$123,507.40	1.0000	$0.00	0.0000
Difference		($123,507.40)	-1.0000	$123,507.40	1.0000

Generation Arrangement Report

Account: MTED-101/6-301
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1952	61.50	$12,096.44	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1946	67.50	$652.82	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1927	86.50	$7,077.29	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	87.50	$26,723.33	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1925	88.50	$10,807.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1924	89.50	$2,206.67	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1922	91.50	$35,824.33	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1921	92.50	$166.67	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1919	94.50	$1,666.67	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1918	95.50	$12,487.98	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1917	96.50	$10,028.20	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1915	98.50	$3,770.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
		$123,507.40	0.00	0.00	0.0000	1.0000	$0.00	$0.00

Remaining Life Depreciation Accrual

Account: MTED-101/6-302
Scenario: Met Ed 2014 ADR Intangible
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$165,168.91	0.49	$165,168.91	100.000000%	100.000000%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$165,168.91 *		$165,168.91	100.000000%	100.000000%
Average:	$165,168.91		$165,168.91	100.000000%	100.000000%
Grand Total:	$165,168.91 *		$165,168.91	100.000000%	100.000000%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED-101/6-302
Scenario: Met Ed 2014 ADR Intangible
Dispersion: 7 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$165,168.91	$0.00	0.0000	$165,168.91	1.0000
Computed	$165,168.91	$153,725.06	0.9307	$11,443.85	0.0693
Difference		($153,725.06)	-0.9307	$153,725.06	0.9307

Generation Arrangement Report

Account: MTED-101/6-302
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2012	1.50	$14,564.90	7.00	5.50	0.7857	1.0000	$11,443.85	$2,080.70
1971	42.50	$825.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1968	45.50	$2,985.52	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1967	46.50	$3,776.05	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1966	47.50	$2,260.57	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1963	50.50	$925.12	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1954	59.50	$1,231.59	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1953	60.50	$5,533.30	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1952	61.50	$4,749.62	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1950	63.50	$433.93	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1944	69.50	$394.89	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1942	71.50	$418.42	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1930	83.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1928	85.50	$780.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1927	86.50	$6,240.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	87.50	$780.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1924	89.50	$2,340.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1923	90.50	$9,360.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1922	91.50	$5,460.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1921	92.50	$13,650.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1920	93.50	$1,170.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1919	94.50	$780.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1918	95.50	$3,510.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1917	96.50	$2,340.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1916	97.50	$4,290.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1914	99.50	$2,340.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1913	100.50	$8,580.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1912	101.50	$10,140.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1911	102.50	$9,360.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1910	103.50	$23,010.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1909	104.50	$1,950.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1908	105.50	$2,340.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1907	106.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

Account: MTED-101/6-302
Dispersion: 7.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1906	107.50	$1,560.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1905	108.50	$1,560.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1903	110.50	$1,560.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1902	111.50	$1,170.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1901	112.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1900	113.50	$780.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1898	115.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1897	116.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1895	118.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1894	119.50	$780.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1893	120.50	$1,170.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1892	121.50	$1,170.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1891	122.50	$5,000.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1890	123.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1886	127.50	$390.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
1885	128.50	$780.00	7.00	0.00	0.0000	0.0000	$0.00	$0.00
		$165,168.91	7.00	0.49	0.0693	1.0000	$11,443.85	$2,080.70

Remaining Life Depreciation Accrual

Account: MTED 101/6-35012 TRANS lines
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$26,933,492.88	38.23	$405,189.81	1.504409%	2.615479%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$26,933,492.88 *		$405,189.81	1.504409%	2.615479%
Average:	$26,933,492.88		$405,189.81	1.504409%	2.615479%
Grand Total:	$26,933,492.88 *		$405,189.81	1.504409%	2.615479%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-35012 TRANS lines
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 80 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$26,933,492.88	$11,441,502.03	0.4248	$15,491,990.85	0.5752
Computed	$26,933,492.88	$14,061,333.61	0.5221	$12,872,159.27	0.4779
Difference		($2,619,831.58)	-0.0973	$2,619,831.58	0.0973

Generation Arrangement Report

Account: MTED 101/6-35012 TRANS lines
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2011	2.50	$598.69	80.00	77.50	0.9688	1.0000	$579.98	$7.48
2009	4.50	$4.84	80.00	75.50	0.9438	1.0000	$4.57	$0.06
2007	6.50	$5,810.40	80.00	73.50	0.9188	1.0000	$5,338.30	$72.63
2003	10.50	$252,332.78	80.00	69.50	0.8688	1.0000	$219,214.10	$3,154.16
1996	17.50	$140.38	80.00	62.50	0.7813	1.0000	$109.67	$1.75
1995	18.50	$115.53	80.00	61.50	0.7688	1.0000	$88.81	$1.44
1994	19.50	$714,064.13	80.00	60.50	0.7563	1.0000	$540,011.00	$8,925.80
1993	20.50	$1,289,627.27	80.00	59.50	0.7438	1.0000	$959,160.28	$16,120.34
1992	21.50	$45,883.80	80.00	58.50	0.7313	1.0000	$33,552.53	$573.55
1991	22.50	$119,303.21	80.00	57.50	0.7188	1.0000	$85,749.18	$1,491.29
1990	23.50	$556,414.29	80.00	56.50	0.7063	1.0000	$392,967.59	$6,955.18
1989	24.50	$8,041.09	80.00	55.50	0.6938	1.0000	$5,578.51	$100.51
1988	25.50	$68,838.58	80.00	54.50	0.6813	1.0000	$46,896.28	$860.48
1987	26.50	$33,007.08	80.00	53.50	0.6688	1.0000	$22,073.48	$412.59
1986	27.50	$65,939.13	80.00	52.50	0.6563	1.0000	$43,272.55	$824.24
1985	28.50	$417,272.31	80.00	51.50	0.6438	1.0000	$268,619.05	$5,215.90
1984	29.50	$218,073.20	80.00	50.50	0.6313	1.0000	$137,658.71	$2,725.92
1983	30.50	$295,517.04	80.00	49.50	0.6188	1.0000	$182,851.17	$3,693.96
1982	31.50	$14,887.51	80.00	48.50	0.6063	1.0000	$9,025.55	$186.09
1981	32.50	$12,944.11	80.00	47.50	0.5938	1.0000	$7,685.57	$161.80
1980	33.50	$114,508.39	80.00	46.50	0.5813	1.0000	$66,558.00	$1,431.35
1979	34.50	$100,125.74	80.00	45.50	0.5688	1.0000	$56,946.51	$1,251.57
1978	35.50	$8,420.26	80.00	44.50	0.5563	1.0000	$4,683.77	$105.25
1977	36.50	$275,265.63	80.00	43.50	0.5438	1.0000	$149,675.69	$3,440.82
1976	37.50	$6,112,490.51	80.00	42.50	0.5313	1.0000	$3,247,260.58	$76,406.13
1975	38.50	$447,702.82	80.00	41.50	0.5188	1.0000	$232,245.84	$5,596.29
1974	39.50	$283,812.63	80.00	40.50	0.5063	1.0000	$143,680.14	$3,547.66
1973	40.50	$2,007,475.04	80.00	39.50	0.4938	1.0000	$991,190.80	$25,093.44
1972	41.50	$472,877.46	80.00	38.50	0.4813	1.0000	$227,572.28	$5,910.97
1971	42.50	$1,266,471.73	80.00	37.50	0.4688	1.0000	$593,658.62	$15,830.90
1970	43.50	$845,645.51	80.00	36.50	0.4563	1.0000	$385,825.76	$10,570.57
1969	44.50	$499,170.03	80.00	35.50	0.4438	1.0000	$221,506.70	$6,239.63
1968	45.50	$1,954,050.94	80.00	34.50	0.4313	1.0000	$842,684.47	$24,425.64

Generation Arrangement Report

Account: MTED 101/6-35012 TRANS lines
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1967	46.50	$3,097,937.83	80.00	33.50	0.4188	1.0000	$1,297,261.47	$38,724.22
1966	47.50	$711,865.75	80.00	32.50	0.4063	1.0000	$289,195.46	$8,898.32
1965	48.50	$272,165.88	80.00	31.50	0.3938	1.0000	$107,165.32	$3,402.07
1964	49.50	$161,209.48	80.00	30.50	0.3813	1.0000	$61,461.11	$2,015.12
1963	50.50	$330,660.51	80.00	29.50	0.3688	1.0000	$121,931.06	$4,133.26
1962	51.50	$78,738.70	80.00	28.50	0.3563	1.0000	$28,050.66	$984.23
1961	52.50	$131,977.42	80.00	27.50	0.3438	1.0000	$45,367.24	$1,649.72
1960	53.50	$67,357.92	80.00	26.50	0.3313	1.0000	$22,312.31	$841.97
1959	54.50	$387,424.80	80.00	25.50	0.3188	1.0000	$123,491.65	$4,842.81
1958	55.50	$39,497.40	80.00	24.50	0.3063	1.0000	$12,096.08	$493.72
1957	56.50	$194,240.54	80.00	23.50	0.2938	1.0000	$57,058.16	$2,428.01
1956	57.50	$159,988.62	80.00	22.50	0.2813	1.0000	$44,996.80	$1,999.86
1955	58.50	$218,293.92	80.00	21.50	0.2688	1.0000	$58,666.49	$2,728.67
1954	59.50	$630,233.45	80.00	20.50	0.2563	1.0000	$161,497.32	$7,877.92
1953	60.50	$609,458.00	80.00	19.50	0.2438	1.0000	$148,555.39	$7,618.23
1952	61.50	$138,944.04	80.00	18.50	0.2313	1.0000	$32,130.81	$1,736.80
1951	62.50	$86,567.94	80.00	17.50	0.2188	1.0000	$18,936.74	$1,082.10
1950	63.50	$201,972.46	80.00	16.50	0.2063	1.0000	$41,656.82	$2,524.66
1949	64.50	$67,095.54	80.00	15.50	0.1938	1.0000	$12,999.76	$838.69
1948	65.50	$57,629.06	80.00	14.50	0.1813	1.0000	$10,445.27	$720.36
1947	66.50	$6,420.22	80.00	13.50	0.1688	1.0000	$1,083.41	$80.25
1946	67.50	$215.95	80.00	12.50	0.1563	1.0000	$33.74	$2.70
1945	68.50	$12,030.13	80.00	11.50	0.1438	1.0000	$1,729.33	$150.38
1944	69.50	$3,053.77	80.00	10.50	0.1313	1.0000	$400.81	$38.17
1943	70.50	$42,642.59	80.00	9.50	0.1188	1.0000	$5,063.81	$533.03
1942	71.50	$29,045.25	80.00	8.50	0.1063	1.0000	$3,086.06	$363.07
1941	72.50	$74,176.31	80.00	7.50	0.0938	1.0000	$6,954.03	$927.20
1940	73.50	$1,737.64	80.00	6.50	0.0813	1.0000	$141.18	$21.72
1939	74.50	$368.25	80.00	5.50	0.0688	1.0000	$25.32	$4.60
1938	75.50	$612,259.53	80.00	4.50	0.0563	1.0000	$34,439.60	$7,653.24
1929	84.50	$313.17	80.00	0.00	0.0000	0.0000	$0.00	$0.00
1924	89.50	$891.75	80.00	0.00	0.0000	0.0000	$0.00	$0.00
1914	99.50	$2.00	80.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

Account: MTED 101/6-35012 TRANS lines
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1907	106.50	$25.00	80.00	0.00	0.0000	0.0000	$0.00	$0.00
1901	112.50	$220.00	80.00	0.00	0.0000	0.0000	$0.00	$0.00
		$26,933,492.88	80.00	38.23	0.4779	1.0000	$12,872,159.27	$336,650.51

Remaining Life Depreciation Accrual

Account: MTED 101/6-352 Structures/improve
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 58.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$6,720,251.60	32.54	$123,768.65	1.841726%	3.073301%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($81,766.79)	0.50	($704.89)	0.862074%	
Total:	$6,720,251.60 *		$123,063.76	1.831237%	3.055798%
Average:	$6,679,368.21		$123,063.76	1.842446%	3.087138%
Grand Total:	$6,720,251.60 *		$123,063.76	1.831237%	3.055798%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-352 Structures/improve
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 58 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$6,720,251.60	$2,693,029.63	0.4007	$4,027,221.97	0.5993
Computed	$6,720,251.60	$2,950,155.17	0.4390	$3,770,096.43	0.5610
Difference		($257,125.54)	-0.0383	$257,125.54	0.0383

Generation Arrangement Report

Account: MTED 101/6-352 Structures/improve
Dispersion: 58.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$115,564.04	58.00	57.51	0.9915	1.0000	$114,582.36	$1,992.48
2012	1.50	$527,355.57	58.00	56.52	0.9746	1.0000	$513,941.60	$9,092.34
2011	2.50	$681,811.78	58.00	55.54	0.9576	1.0000	$652,935.69	$11,755.38
2007	6.50	$2,116.65	58.00	51.65	0.8905	1.0000	$1,884.80	$36.49
2006	7.50	$10,711.03	58.00	50.68	0.8738	1.0000	$9,359.30	$184.67
2003	10.50	$856.48	58.00	47.80	0.8242	1.0000	$705.92	$14.77
2001	12.50	$118,437.06	58.00	45.91	0.7915	1.0000	$93,744.49	$2,042.02
2000	13.50	$28,523.81	58.00	44.97	0.7753	1.0000	$22,114.64	$491.79
1999	14.50	$17,215.09	58.00	44.03	0.7592	1.0000	$13,069.20	$296.81
1998	15.50	$4,008.60	58.00	43.10	0.7431	1.0000	$2,978.92	$69.11
1996	17.50	$22,039.63	58.00	41.26	0.7114	1.0000	$15,678.25	$379.99
1995	18.50	$8,844.99	58.00	40.35	0.6956	1.0000	$6,152.86	$152.50
1994	19.50	$61,378.57	58.00	39.44	0.6800	1.0000	$41,738.08	$1,058.25
1993	20.50	$13,360.88	58.00	38.54	0.6645	1.0000	$8,878.67	$230.36
1992	21.50	$145,373.97	58.00	37.65	0.6491	1.0000	$94,368.40	$2,506.45
1991	22.50	$388,261.82	58.00	36.76	0.6339	1.0000	$246,109.44	$6,694.17
1990	23.50	$430,859.49	58.00	35.89	0.6187	1.0000	$266,585.40	$7,428.61
1989	24.50	$11,649.27	58.00	35.02	0.6038	1.0000	$7,033.25	$200.85
1988	25.50	$189,670.87	58.00	34.15	0.5889	1.0000	$111,692.15	$3,270.19
1987	26.50	$26,159.62	58.00	33.30	0.5741	1.0000	$15,019.08	$451.03
1986	27.50	$326,108.13	58.00	32.45	0.5596	1.0000	$182,477.19	$5,622.55
1985	28.50	$813,258.20	58.00	31.62	0.5451	1.0000	$443,311.09	$14,021.69
1984	29.50	$16,541.60	58.00	30.79	0.5308	1.0000	$8,780.13	$285.20
1983	30.50	$47,435.12	58.00	29.96	0.5166	1.0000	$24,505.57	$817.85
1982	31.50	$16,828.77	58.00	29.15	0.5026	1.0000	$8,458.69	$290.15
1981	32.50	$1,155.53	58.00	28.35	0.4888	1.0000	$564.79	$19.92
1980	33.50	$1,203.31	58.00	27.55	0.4751	1.0000	$571.65	$20.75
1978	35.50	$1,291.00	58.00	25.99	0.4482	1.0000	$578.59	$22.26
1977	36.50	$12,628.40	58.00	25.23	0.4349	1.0000	$5,492.69	$217.73
1976	37.50	$520,759.70	58.00	24.47	0.4219	1.0000	$219,703.14	$8,978.62
1975	38.50	$15,881.75	58.00	23.73	0.4091	1.0000	$6,496.54	$273.82
1974	39.50	$4,418.89	58.00	22.99	0.3964	1.0000	$1,751.50	$76.19
1973	40.50	$223,885.85	58.00	22.26	0.3839	1.0000	$85,939.10	$3,860.10

Generation Arrangement Report

Account: MTED 101/6-352 Structures/improve
Dispersion: 58.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1972	41.50	$78,917.81	58.00	21.55	0.3715	1.0000	$29,319.64	$1,360.65
1971	42.50	$182,292.59	58.00	20.85	0.3594	1.0000	$65,524.29	$3,142.98
1970	43.50	$458,817.08	58.00	20.16	0.3475	1.0000	$159,450.54	$7,910.64
1969	44.50	$161,790.02	58.00	19.48	0.3358	1.0000	$54,329.81	$2,789.48
1968	45.50	$169,691.80	58.00	18.81	0.3244	1.0000	$55,039.58	$2,925.72
1967	46.50	$3,072.67	58.00	18.16	0.3131	1.0000	$962.00	$52.98
1966	47.50	$93,939.69	58.00	17.52	0.3020	1.0000	$28,373.25	$1,619.65
1965	48.50	$20,753.26	58.00	16.89	0.2912	1.0000	$6,043.67	$357.81
1964	49.50	$1,948.25	58.00	16.28	0.2807	1.0000	$546.90	$33.59
1963	50.50	$83,377.78	58.00	15.68	0.2704	1.0000	$22,545.98	$1,437.55
1962	51.50	$33,966.72	58.00	15.10	0.2604	1.0000	$8,843.27	$585.63
1961	52.50	$230.12	58.00	14.53	0.2506	1.0000	$57.66	$3.97
1960	53.50	$306.55	58.00	13.98	0.2411	1.0000	$73.91	$5.29
1959	54.50	$3,674.92	58.00	13.45	0.2319	1.0000	$852.09	$63.36
1958	55.50	$56,306.56	58.00	12.93	0.2229	1.0000	$12,550.82	$970.80
1957	56.50	$4,813.27	58.00	12.43	0.2143	1.0000	$1,031.33	$82.99
1956	57.50	$965.78	58.00	11.94	0.2059	1.0000	$198.84	$16.65
1955	58.50	$40,439.48	58.00	11.47	0.1978	1.0000	$7,997.92	$697.23
1954	59.50	$385,982.74	58.00	11.02	0.1899	1.0000	$73,317.33	$6,654.87
1953	60.50	$4,365.90	58.00	10.58	0.1824	1.0000	$796.51	$75.27
1952	61.50	$9,802.69	58.00	10.16	0.1752	1.0000	$1,717.24	$169.01
1951	62.50	$10,249.96	58.00	9.76	0.1682	1.0000	$1,723.99	$176.72
1950	63.50	$114.70	58.00	9.37	0.1615	1.0000	$18.52	$1.98
1949	64.50	$2,483.47	58.00	8.99	0.1550	1.0000	$384.97	$42.82
1948	65.50	$3,450.08	58.00	8.63	0.1488	1.0000	$513.39	$59.48
1947	66.50	$121.29	58.00	8.29	0.1428	1.0000	$17.33	$2.09
1946	67.50	$177.20	58.00	7.95	0.1371	1.0000	$24.29	$3.06
1944	69.50	$16.48	58.00	7.32	0.1262	1.0000	$2.08	$0.28
1943	70.50	$22,891.38	58.00	7.02	0.1211	1.0000	$2,771.23	$394.68
1942	71.50	$989.13	58.00	6.73	0.1160	1.0000	$114.70	$17.05
1941	72.50	$7,051.74	58.00	6.44	0.1111	1.0000	$783.47	$121.58
1940	73.50	$1,225.20	58.00	6.17	0.1064	1.0000	$130.35	$21.12

Generation Arrangement Report

Account: MTED 101/6-352 Structures/improve
Dispersion: 58.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1938	75.50	$70,429.82	58.00	5.63	0.0971	1.0000	$6,836.44	$1,214.31
		$6,720,251.60	58.00	32.54	0.5610	1.0000	$3,770,096.43	$115,866.41

Remaining Life Depreciation Accrual

Account: MTED 101/6-353 Station equipment
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 54.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$182,774,706.85	41.49	$3,070,848.81	1.680128%	2.410386%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($1,519,777.21)	0.50	($14,072.01)	0.925926%	
Total:	$182,774,706.85 *		$3,056,776.80	1.672429%	2.399341%
Average:	$182,014,818.25		$3,056,776.80	1.679411%	2.413738%
Grand Total:	$182,774,706.85 *		$3,056,776.80	1.672429%	2.399341%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-353 Station equipment
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 54 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$182,774,706.85	$55,374,009.34	0.3030	$127,400,697.51	0.6970
Computed	$182,774,706.85	$42,352,527.87	0.2317	$140,422,178.98	0.7683
Difference		$13,021,481.47	0.0712	($13,021,481.47)	-0.0712

Generation Arrangement Report

Account: MTED 101/6-353 Station equipment
Dispersion: 54.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$17,711,242.73	54.00	53.59	0.9924	1.0000	$17,575,973.29	$327,985.98
2012	1.50	$15,088,016.24	54.00	52.77	0.9772	1.0000	$14,743,429.52	$279,407.71
2011	2.50	$9,336,502.49	54.00	51.95	0.9620	1.0000	$8,981,971.24	$172,898.19
2010	3.50	$5,430,008.11	54.00	51.14	0.9470	1.0000	$5,142,175.11	$100,555.71
2009	4.50	$5,534,612.62	54.00	50.33	0.9320	1.0000	$5,158,411.24	$102,492.83
2008	5.50	$22,539,649.56	54.00	49.53	0.9171	1.0000	$20,671,916.03	$417,400.92
2007	6.50	$1,136,930.86	54.00	48.73	0.9023	1.0000	$1,025,889.19	$21,054.28
2006	7.50	$15,018,631.61	54.00	47.93	0.8876	1.0000	$13,330,426.73	$278,122.81
2005	8.50	$1,196,085.76	54.00	47.14	0.8729	1.0000	$1,044,121.49	$22,149.74
2004	9.50	$2,138,089.13	54.00	46.35	0.8584	1.0000	$1,835,265.26	$39,594.24
2003	10.50	$1,553,017.81	54.00	45.57	0.8439	1.0000	$1,310,588.26	$28,759.59
2002	11.50	$854,624.86	54.00	44.79	0.8295	1.0000	$708,907.40	$15,826.39
2001	12.50	$1,972,949.42	54.00	44.02	0.8152	1.0000	$1,608,282.29	$36,536.10
2000	13.50	$4,164,821.23	54.00	43.25	0.8009	1.0000	$3,335,712.11	$77,126.32
1999	14.50	$373,481.18	54.00	42.49	0.7868	1.0000	$293,840.63	$6,916.32
1998	15.50	$2,352,556.40	54.00	41.72	0.7727	1.0000	$1,817,767.21	$43,565.86
1997	16.50	$3,174,547.96	54.00	40.97	0.7587	1.0000	$2,408,424.47	$58,787.93
1996	17.50	$1,316,481.42	54.00	40.22	0.7448	1.0000	$980,487.40	$24,379.29
1995	18.50	$2,061,051.55	54.00	39.47	0.7310	1.0000	$1,506,527.97	$38,167.62
1994	19.50	$4,818,901.86	54.00	38.73	0.7172	1.0000	$3,456,185.40	$89,238.92
1993	20.50	$1,542,148.13	54.00	37.99	0.7036	1.0000	$1,085,001.61	$28,558.30
1992	21.50	$5,142,419.52	54.00	37.26	0.6900	1.0000	$3,548,302.56	$95,229.99
1991	22.50	$2,905,098.40	54.00	36.53	0.6766	1.0000	$1,965,446.64	$53,798.12
1990	23.50	$1,206,121.63	54.00	35.81	0.6632	1.0000	$799,889.69	$22,335.59
1989	24.50	$1,909,405.54	54.00	35.10	0.6500	1.0000	$1,241,043.16	$35,359.36
1988	25.50	$695,245.92	54.00	34.39	0.6368	1.0000	$442,747.84	$12,874.92
1987	26.50	$1,528,105.30	54.00	33.68	0.6238	1.0000	$953,216.75	$28,298.25
1986	27.50	$5,955,111.88	54.00	32.99	0.6109	1.0000	$3,637,805.84	$110,279.85
1985	28.50	$3,273,016.86	54.00	32.30	0.5981	1.0000	$1,957,481.92	$60,611.42
1984	29.50	$937,822.05	54.00	31.61	0.5854	1.0000	$548,989.05	$17,367.08
1983	30.50	$1,999,765.58	54.00	30.93	0.5729	1.0000	$1,145,584.85	$37,032.70
1982	31.50	$290,631.19	54.00	30.26	0.5604	1.0000	$162,881.63	$5,382.06
1981	32.50	$306,681.83	54.00	29.60	0.5482	1.0000	$168,108.26	$5,679.29

Generation Arrangement Report

Account: MTED 101/6-353 Station equipment
Dispersion: 54.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$136,481.87	54.00	28.94	0.5360	1.0000	$73,153.05	$2,527.44
1979	34.50	$164,033.48	54.00	28.29	0.5240	1.0000	$85,949.01	$3,037.66
1978	35.50	$359,976.38	54.00	27.65	0.5121	1.0000	$184,341.73	$6,666.23
1977	36.50	$627,965.42	54.00	27.02	0.5004	1.0000	$314,209.16	$11,628.99
1976	37.50	$10,927,192.05	54.00	26.40	0.4888	1.0000	$5,341,325.67	$202,355.41
1975	38.50	$1,397,460.57	54.00	25.78	0.4774	1.0000	$667,123.03	$25,878.90
1974	39.50	$171,627.72	54.00	25.17	0.4661	1.0000	$79,996.94	$3,178.29
1973	40.50	$2,225,820.54	54.00	24.57	0.4550	1.0000	$1,012,722.35	$41,218.90
1972	41.50	$2,112,311.72	54.00	23.98	0.4440	1.0000	$937,928.46	$39,116.88
1971	42.50	$3,032,055.86	54.00	23.39	0.4332	1.0000	$1,313,579.80	$56,149.18
1970	43.50	$3,913,011.65	54.00	22.82	0.4226	1.0000	$1,653,626.56	$72,463.18
1969	44.50	$2,016,255.10	54.00	22.26	0.4122	1.0000	$831,024.81	$37,338.06
1968	45.50	$1,672,176.69	54.00	21.70	0.4019	1.0000	$671,993.84	$30,966.24
1967	46.50	$273,895.63	54.00	21.15	0.3918	1.0000	$107,299.30	$5,072.14
1966	47.50	$734,335.72	54.00	20.62	0.3818	1.0000	$280,371.97	$13,598.81
1965	48.50	$417,778.99	54.00	20.09	0.3720	1.0000	$155,425.18	$7,736.65
1964	49.50	$280,660.42	54.00	19.57	0.3624	1.0000	$101,720.02	$5,197.42
1963	50.50	$964,183.06	54.00	19.06	0.3530	1.0000	$340,363.30	$17,855.24
1962	51.50	$1,148,454.27	54.00	18.57	0.3438	1.0000	$394,839.92	$21,267.67
1961	52.50	$73,714.48	54.00	18.08	0.3347	1.0000	$24,675.46	$1,365.08
1960	53.50	$37,385.01	54.00	17.60	0.3259	1.0000	$12,182.63	$692.32
1959	54.50	$82,021.29	54.00	17.13	0.3172	1.0000	$26,014.90	$1,518.91
1958	55.50	$387,087.62	54.00	16.67	0.3087	1.0000	$119,476.73	$7,168.29
1957	56.50	$62,048.43	54.00	16.22	0.3003	1.0000	$18,634.49	$1,149.04
1956	57.50	$27,159.28	54.00	15.78	0.2922	1.0000	$7,935.25	$502.95
1955	58.50	$350,309.27	54.00	15.35	0.2842	1.0000	$99,556.25	$6,487.21
1954	59.50	$2,470,352.51	54.00	14.93	0.2764	1.0000	$682,781.44	$45,747.27
1953	60.50	$99,103.12	54.00	14.51	0.2688	1.0000	$26,634.80	$1,835.24
1952	61.50	$524,611.28	54.00	14.11	0.2613	1.0000	$137,081.14	$9,715.02
1951	62.50	$183,303.34	54.00	13.72	0.2540	1.0000	$46,559.82	$3,394.51
1950	63.50	$25,425.20	54.00	13.33	0.2469	1.0000	$6,276.82	$470.84
1949	64.50	$10,109.54	54.00	12.95	0.2399	1.0000	$2,425.17	$187.21
1948	65.50	$11,564.26	54.00	12.59	0.2331	1.0000	$2,695.23	$214.15

Generation Arrangement Report

Account: MTED 101/6-353 Station equipment
Dispersion: 54.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$3,959.46	54.00	12.22	0.2264	1.0000	$896.37	$73.32
1946	67.50	$4,539.60	54.00	11.87	0.2199	1.0000	$998.06	$84.07
1945	68.50	$210.47	54.00	11.53	0.2135	1.0000	$44.93	$3.90
1944	69.50	$63.23	54.00	11.19	0.2072	1.0000	$13.10	$1.17
1943	70.50	$169,340.16	54.00	10.86	0.2011	1.0000	$34,047.27	$3,135.93
1942	71.50	$10,729.47	54.00	10.53	0.1950	1.0000	$2,091.97	$198.69
1941	72.50	$107,057.03	54.00	10.21	0.1890	1.0000	$20,238.23	$1,982.54
1940	73.50	$5,236.29	54.00	9.89	0.1832	1.0000	$959.37	$96.97
1938	75.50	$239.19	54.00	9.28	0.1718	1.0000	$41.10	$4.43
1937	76.50	$9.93	54.00	8.98	0.1663	1.0000	$1.65	$0.18
1935	78.50	$207.77	54.00	8.39	0.1553	1.0000	$32.27	$3.85
1931	82.50	$1,999.70	54.00	7.26	0.1344	1.0000	$268.81	$37.03
1930	83.50	$7,822.42	54.00	6.99	0.1294	1.0000	$1,012.33	$144.86
1929	84.50	$13,003.33	54.00	6.72	0.1244	1.0000	$1,617.17	$240.80
1928	85.50	$1,055.93	54.00	6.45	0.1195	1.0000	$126.18	$19.55
1927	86.50	$15,345.49	54.00	6.20	0.1147	1.0000	$1,760.54	$284.18
1926	87.50	$13,413.17	54.00	5.94	0.1101	1.0000	$1,476.45	$248.39
1925	88.50	$30,965.46	54.00	5.70	0.1055	1.0000	$3,268.21	$573.43
1924	89.50	$16.03	54.00	5.46	0.1011	1.0000	$1.62	$0.30
1923	90.50	$5,325.98	54.00	5.23	0.0969	1.0000	$515.93	$98.63
1922	91.50	$130.19	54.00	4.99	0.0925	1.0000	$12.04	$2.41
1921	92.50	$75.66	54.00	4.77	0.0883	1.0000	$6.68	$1.40
1919	94.50	$263.37	54.00	4.33	0.0801	1.0000	$21.10	$4.88
1909	104.50	$49.12	54.00	1.45	0.0268	1.0000	$1.32	$0.91
		$182,774,706.85	54.00	41.49	0.7683	1.0000	$140,422,178.98	$3,384,716.79

Remaining Life Depreciation Accrual

Account: MTED 101/6-354 Towers & Fixtures
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 65.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$41,082,523.92	30.36	$476,490.82	1.159838%	3.293486%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($503,192.29)	0.50	($3,870.71)	0.769231%	
Total:	$41,082,523.92 *		$472,620.11	1.150416%	3.266732%
Average:	$40,830,927.78		$472,620.11	1.157505%	3.324547%
Grand Total:	$41,082,523.92 *		$472,620.11	1.150416%	3.266732%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-354 Towers & Fixtures
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 65 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$41,082,523.92	$26,614,851.88	0.6478	$14,467,672.04	0.3522
Computed	$41,082,523.92	$21,891,953.53	0.5329	$19,190,570.39	0.4671
Difference		$4,722,898.35	0.1150	($4,722,898.35)	-0.1150

Generation Arrangement Report

Account: MTED 101/6-354 Towers & Fixtures
Dispersion: 65.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2012	1.50	$1,761,705.82	65.00	63.52	0.9773	1.0000	$1,721,710.06	$27,103.17
2011	2.50	$2,534,903.85	65.00	62.54	0.9622	1.0000	$2,439,063.33	$38,998.52
2007	6.50	($859.01)	65.00	58.64	0.9022	1.0000	($774.97)	($13.22)
2002	11.50	$9,249.26	65.00	53.83	0.8281	1.0000	$7,659.52	$142.30
2001	12.50	$95,829.19	65.00	52.88	0.8135	1.0000	$77,956.38	$1,474.30
1998	15.50	$1,467.10	65.00	50.05	0.7700	1.0000	$1,129.60	$22.57
1993	20.50	$132,283.11	65.00	45.43	0.6989	1.0000	$92,449.19	$2,035.12
1992	21.50	$39,700.54	65.00	44.52	0.6849	1.0000	$27,192.32	$610.78
1991	22.50	$10,026.50	65.00	43.62	0.6711	1.0000	$6,728.32	$154.25
1989	24.50	$26,995.32	65.00	41.83	0.6436	1.0000	$17,374.16	$415.31
1986	27.50	$604,439.36	65.00	39.21	0.6032	1.0000	$364,583.10	$9,299.07
1985	28.50	$1,131,748.22	65.00	38.34	0.5899	1.0000	$667,609.69	$17,411.51
1984	29.50	$978,223.02	65.00	37.49	0.5767	1.0000	$564,189.10	$15,049.58
1976	37.50	$10,301,082.61	65.00	30.91	0.4756	1.0000	$4,898,976.34	$158,478.19
1974	39.50	$645,296.58	65.00	29.35	0.4515	1.0000	$291,368.40	$9,927.64
1973	40.50	$329,661.86	65.00	28.58	0.4397	1.0000	$144,956.79	$5,071.72
1972	41.50	$173,400.62	65.00	27.82	0.4280	1.0000	$74,215.00	$2,667.70
1971	42.50	$2,263,525.90	65.00	27.07	0.4165	1.0000	$942,653.67	$34,823.48
1970	43.50	$2,521,730.04	65.00	26.33	0.4050	1.0000	$1,021,346.34	$38,795.85
1968	45.50	$4,679,465.36	65.00	24.87	0.3826	1.0000	$1,790,452.39	$71,991.77
1967	46.50	$6,612,656.50	65.00	24.15	0.3716	1.0000	$2,457,331.58	$101,733.18
1966	47.50	$1,337,384.34	65.00	23.45	0.3608	1.0000	$482,558.65	$20,575.14
1965	48.50	$4,008.81	65.00	22.76	0.3501	1.0000	$1,403.61	$61.67
1964	49.50	$24.52	65.00	22.08	0.3397	1.0000	$8.33	$0.38
1963	50.50	$50,713.84	65.00	21.41	0.3293	1.0000	$16,700.91	$780.21
1962	51.50	$55,077.00	65.00	20.75	0.3192	1.0000	$17,580.63	$847.34
1960	53.50	$17,765.87	65.00	19.46	0.2995	1.0000	$5,320.00	$273.32
1959	54.50	$180,389.43	65.00	18.84	0.2898	1.0000	$52,283.13	$2,775.22
1957	56.50	$128,568.38	65.00	17.63	0.2713	1.0000	$34,874.44	$1,977.98
1956	57.50	$26,134.23	65.00	17.05	0.2623	1.0000	$6,854.53	$402.07
1955	58.50	$109,452.98	65.00	16.48	0.2535	1.0000	$27,745.37	$1,683.89
1954	59.50	$2,484,182.81	65.00	15.92	0.2449	1.0000	$608,349.56	$38,218.20
1953	60.50	$970,063.28	65.00	15.38	0.2366	1.0000	$229,500.18	$14,924.05

Generation Arrangement Report

Account: MTED 101/6-354 Towers & Fixtures
Dispersion: 65.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1951	62.50	$54,557.17	65.00	14.34	0.2206	1.0000	$12,032.93	$839.34
1950	63.50	$85,910.00	65.00	13.84	0.2129	1.0000	$18,286.37	$1,321.69
1948	65.50	$2,335.61	65.00	12.88	0.1982	1.0000	$462.88	$35.93
1943	70.50	$1,939.14	65.00	10.75	0.1654	1.0000	$320.75	$29.83
1941	72.50	$128,574.12	65.00	10.00	0.1538	1.0000	$19,774.27	$1,978.06
1940	73.50	$9,720.09	65.00	9.64	0.1483	1.0000	$1,441.15	$149.54
1931	82.50	$13,302.87	65.00	6.88	0.1058	1.0000	$1,407.08	$204.66
1930	83.50	$9,071.14	65.00	6.60	0.1016	1.0000	$921.30	$139.56
1929	84.50	$4,164.81	65.00	6.34	0.0975	1.0000	$406.07	$64.07
1928	85.50	$44,404.24	65.00	6.08	0.0936	1.0000	$4,155.60	$683.14
1926	87.50	$2,669.76	65.00	5.56	0.0856	1.0000	$228.53	$41.07
1925	88.50	$59,148.39	65.00	5.30	0.0815	1.0000	$4,820.65	$909.98
1924	89.50	$447,111.66	65.00	5.05	0.0777	1.0000	$34,726.96	$6,878.64
1923	90.50	$2,313.86	65.00	4.78	0.0736	1.0000	$170.26	$35.60
1921	92.50	$1,003.82	65.00	4.27	0.0657	1.0000	$65.91	$15.44
		$41,082,523.92	65.00	30.36	0.4671	1.0000	$19,190,570.39	$632,038.83

Remaining Life Depreciation Accrual

Account: MTED 101/6-355 Poles & Fixtures
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 62.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$46,196,355.38	41.97	$672,510.91	1.455766%	2.382549%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($226,356.08)	0.50	($1,825.45)	0.806451%	
Total:	$46,196,355.38 *		$670,685.46	1.451815%	2.376082%
Average:	$46,083,177.34		$670,685.46	1.455380%	2.385647%
Grand Total:	$46,196,355.38 *		$670,685.46	1.451815%	2.376082%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-355 Poles & Fixtures
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 62 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$46,196,355.38	$17,969,822.96	0.3890	$28,226,532.42	0.6110
Computed	$46,196,355.38	$14,923,018.66	0.3230	$31,273,336.72	0.6770
Difference		$3,046,804.30	0.0660	($3,046,804.30)	-0.0660

Generation Arrangement Report

Account: MTED 101/6-355 Poles & Fixtures
Dispersion: 62.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$3,029,409.59	62.00	61.51	0.9921	1.0000	$3,005,332.18	$48,861.45
2012	1.50	$3,271,398.34	62.00	60.52	0.9762	1.0000	$3,193,543.14	$52,764.49
2011	2.50	$535,871.97	62.00	59.54	0.9604	1.0000	$514,635.39	$8,643.10
2010	3.50	$442,549.94	62.00	58.56	0.9446	1.0000	$418,023.23	$7,137.90
2009	4.50	$813,013.04	62.00	57.59	0.9288	1.0000	$755,155.04	$13,113.11
2008	5.50	$1,208,501.98	62.00	56.61	0.9131	1.0000	$1,103,515.97	$19,491.97
2007	6.50	$176,834.00	62.00	55.64	0.8975	1.0000	$158,703.35	$2,852.16
2006	7.50	$620,340.34	62.00	54.68	0.8819	1.0000	$547,051.75	$10,005.49
2005	8.50	$746,112.64	62.00	53.71	0.8663	1.0000	$646,350.75	$12,034.07
2004	9.50	$193,787.37	62.00	52.75	0.8508	1.0000	$164,873.54	$3,125.60
2003	10.50	$589,122.70	62.00	51.79	0.8354	1.0000	$492,125.40	$9,501.98
2002	11.50	$980,582.22	62.00	50.84	0.8200	1.0000	$804,047.34	$15,815.84
2001	12.50	$711,438.68	62.00	49.89	0.8047	1.0000	$572,469.52	$11,474.82
2000	13.50	$409,303.59	62.00	48.94	0.7894	1.0000	$323,112.92	$6,601.67
1999	14.50	$1,429,600.75	62.00	48.00	0.7743	1.0000	$1,106,884.99	$23,058.08
1998	15.50	$2,037,784.45	62.00	47.07	0.7592	1.0000	$1,547,026.32	$32,867.49
1997	16.50	$842,135.06	62.00	46.14	0.7442	1.0000	$626,682.21	$13,582.82
1996	17.50	$328,169.07	62.00	45.21	0.7293	1.0000	$239,319.23	$5,293.05
1995	18.50	$1,784,836.16	62.00	44.29	0.7144	1.0000	$1,275,109.40	$28,787.68
1994	19.50	$572,372.29	62.00	43.38	0.6997	1.0000	$400,483.98	$9,231.81
1993	20.50	$3,204,761.56	62.00	42.47	0.6850	1.0000	$2,195,415.86	$51,689.70
1992	21.50	$785,000.00	62.00	41.57	0.6705	1.0000	$526,341.99	$12,661.29
1991	22.50	$782,794.43	62.00	40.68	0.6561	1.0000	$513,571.70	$12,625.72
1990	23.50	$2,013,233.04	62.00	39.79	0.6417	1.0000	$1,291,972.24	$32,471.50
1989	24.50	$504,555.78	62.00	38.90	0.6275	1.0000	$316,608.32	$8,138.00
1988	25.50	$1,464,033.72	62.00	38.03	0.6134	1.0000	$898,058.10	$23,613.45
1987	26.50	$1,083,455.82	62.00	37.16	0.5994	1.0000	$649,426.41	$17,475.09
1986	27.50	$1,006,871.14	62.00	36.30	0.5855	1.0000	$589,567.27	$16,239.86
1985	28.50	$3,108,695.61	62.00	35.45	0.5718	1.0000	$1,777,492.74	$50,140.25
1984	29.50	$425,251.10	62.00	34.60	0.5581	1.0000	$237,343.30	$6,858.89
1983	30.50	$750,166.09	62.00	33.77	0.5446	1.0000	$408,571.13	$12,099.45
1982	31.50	$253,926.31	62.00	32.94	0.5312	1.0000	$134,897.37	$4,095.59
1981	32.50	$568,289.01	62.00	32.12	0.5180	1.0000	$294,376.31	$9,165.95

Generation Arrangement Report

Account: MTED 101/6-355 Poles & Fixtures
Dispersion: 62.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$372,645.44	62.00	31.30	0.5049	1.0000	$188,138.95	$6,010.41
1979	34.50	$316,174.63	62.00	30.50	0.4919	1.0000	$155,514.76	$5,099.59
1978	35.50	$76,469.24	62.00	29.70	0.4790	1.0000	$36,631.76	$1,233.37
1977	36.50	$568,148.12	62.00	28.91	0.4663	1.0000	$264,934.32	$9,163.68
1976	37.50	$17,924.73	62.00	28.13	0.4538	1.0000	$8,133.49	$289.11
1975	38.50	$497,162.54	62.00	27.36	0.4413	1.0000	$219,410.16	$8,018.75
1974	39.50	$439,401.18	62.00	26.60	0.4290	1.0000	$188,513.12	$7,087.12
1973	40.50	$981,611.70	62.00	25.85	0.4169	1.0000	$409,251.56	$15,832.45
1972	41.50	$756,300.08	62.00	25.11	0.4049	1.0000	$306,247.83	$12,198.39
1971	42.50	$710,921.38	62.00	24.37	0.3931	1.0000	$279,453.73	$11,466.47
1970	43.50	$1,018,609.67	62.00	23.65	0.3815	1.0000	$388,567.15	$16,429.19
1969	44.50	$385,871.75	62.00	22.94	0.3700	1.0000	$142,758.06	$6,223.74
1968	45.50	$491,264.98	62.00	22.24	0.3587	1.0000	$176,202.37	$7,923.63
1967	46.50	$267,852.95	62.00	21.55	0.3475	1.0000	$93,085.02	$4,320.21
1966	47.50	$257,476.88	62.00	20.87	0.3365	1.0000	$86,651.35	$4,152.85
1965	48.50	$158,655.76	62.00	20.20	0.3258	1.0000	$51,691.99	$2,558.96
1964	49.50	$148,518.34	62.00	19.54	0.3152	1.0000	$46,816.14	$2,395.46
1963	50.50	$263,705.76	62.00	18.90	0.3049	1.0000	$80,397.74	$4,253.32
1962	51.50	$99,192.90	62.00	18.27	0.2947	1.0000	$29,232.42	$1,599.89
1961	52.50	$173,089.67	62.00	17.65	0.2847	1.0000	$49,283.01	$2,791.77
1960	53.50	$144,426.48	62.00	17.05	0.2750	1.0000	$39,721.47	$2,329.46
1959	54.50	$277,937.54	62.00	16.46	0.2655	1.0000	$73,793.42	$4,482.86
1958	55.50	$47,759.91	62.00	15.88	0.2562	1.0000	$12,235.69	$770.32
1957	56.50	$198,812.66	62.00	15.33	0.2472	1.0000	$49,144.63	$3,206.66
1956	57.50	$99,278.54	62.00	14.78	0.2384	1.0000	$23,664.35	$1,601.27
1955	58.50	$68,582.94	62.00	14.25	0.2298	1.0000	$15,762.27	$1,106.18
1954	59.50	$95,291.90	62.00	13.73	0.2215	1.0000	$21,106.94	$1,536.97
1953	60.50	$61,031.96	62.00	13.23	0.2134	1.0000	$13,024.29	$984.39
1952	61.50	$97,525.46	62.00	12.75	0.2056	1.0000	$20,052.06	$1,572.99
1951	62.50	$45,938.97	62.00	12.28	0.1980	1.0000	$9,096.83	$740.95
1950	63.50	$127,719.88	62.00	11.82	0.1907	1.0000	$24,357.40	$2,060.00
1949	64.50	$102,077.60	62.00	11.38	0.1836	1.0000	$18,743.83	$1,646.41
1948	65.50	$57,147.30	62.00	10.96	0.1768	1.0000	$10,102.36	$921.73

Generation Arrangement Report

Account: MTED 101/6-355 Poles & Fixtures
Dispersion: 62.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$6,507.93	62.00	10.55	0.1702	1.0000	$1,107.56	$104.97
1946	67.50	$1,397.44	62.00	10.16	0.1638	1.0000	$228.93	$22.54
1945	68.50	$886.26	62.00	9.78	0.1577	1.0000	$139.75	$14.29
1944	69.50	$2,207.87	62.00	9.41	0.1518	1.0000	$335.08	$35.61
1943	70.50	$20,762.85	62.00	9.06	0.1461	1.0000	$3,032.82	$334.88
1942	71.50	$2,753.24	62.00	8.71	0.1405	1.0000	$386.96	$44.41
1941	72.50	$46,796.33	62.00	8.39	0.1352	1.0000	$6,329.12	$754.78
1940	73.50	$3,084.38	62.00	8.07	0.1302	1.0000	$401.44	$49.75
1939	74.50	$265.23	62.00	7.76	0.1251	1.0000	$33.19	$4.28
1938	75.50	$12,263.11	62.00	7.46	0.1204	1.0000	$1,475.88	$197.79
1929	84.50	$704.11	62.00	5.03	0.0811	1.0000	$57.13	$11.36
		$46,196,355.38	62.00	41.97	0.6770	1.0000	$31,273,336.72	$745,102.51

Remaining Life Depreciation Accrual

Account: MTED 101/6-356 Overhead Conductor
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 65.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$67,409,524.29	42.87	$892,938.15	1.324647%	2.332716%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($453,109.78)	0.50	($3,485.46)	0.769231%	
Total:	$67,409,524.29 *		$889,452.69	1.319476%	2.323611%
Average:	$67,182,969.40		$889,452.69	1.323926%	2.337445%
Grand Total:	$67,409,524.29 *		$889,452.69	1.319476%	2.323611%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-356 Overhead Conductor
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 65 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$67,409,524.29	$29,130,620.58	0.4321	$38,278,903.71	0.5679
Computed	$67,409,524.29	$22,951,923.32	0.3405	$44,457,600.97	0.6595
Difference		$6,178,697.26	0.0917	($6,178,697.26)	-0.0917

Generation Arrangement Report

Account: MTED 101/6-356 Overhead Conductor
Dispersion: 65.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$2,584,860.78	65.00	64.53	0.9927	1.0000	$2,566,049.23	$39,767.09
2012	1.50	$5,028,149.84	65.00	63.58	0.9782	1.0000	$4,918,656.76	$77,356.15
2011	2.50	$897,488.62	65.00	62.64	0.9637	1.0000	$864,953.97	$13,807.52
2010	3.50	$769,697.05	65.00	61.71	0.9493	1.0000	$730,700.25	$11,841.49
2009	4.50	$1,408,079.60	65.00	60.77	0.9350	1.0000	$1,316,490.94	$21,662.76
2008	5.50	$3,351,810.27	65.00	59.84	0.9206	1.0000	$3,085,792.55	$51,566.31
2007	6.50	$457,618.95	65.00	58.91	0.9064	1.0000	$414,766.20	$7,040.29
2006	7.50	$1,821,145.51	65.00	57.99	0.8921	1.0000	$1,624,717.48	$28,017.62
2005	8.50	$1,616,952.13	65.00	57.07	0.8780	1.0000	$1,419,654.28	$24,876.19
2004	9.50	$3,052,092.65	65.00	56.15	0.8639	1.0000	$2,636,617.44	$46,955.27
2003	10.50	$255,864.77	65.00	55.24	0.8498	1.0000	$217,444.05	$3,936.38
2002	11.50	$1,443,116.83	65.00	54.33	0.8358	1.0000	$1,206,222.41	$22,201.80
2001	12.50	$2,392,242.42	65.00	53.43	0.8219	1.0000	$1,966,289.58	$36,803.73
2000	13.50	$256,023.11	65.00	52.53	0.8081	1.0000	$206,889.29	$3,938.82
1999	14.50	$330,834.47	65.00	51.63	0.7943	1.0000	$262,786.40	$5,089.76
1998	15.50	$497,385.14	65.00	50.74	0.7806	1.0000	$388,255.92	$7,652.08
1997	16.50	$272,294.69	65.00	49.85	0.7670	1.0000	$208,841.78	$4,189.15
1996	17.50	$58,164.94	65.00	48.97	0.7534	1.0000	$43,821.74	$894.85
1995	18.50	$852,897.69	65.00	48.10	0.7399	1.0000	$631,085.59	$13,121.50
1994	19.50	$422,225.73	65.00	47.22	0.7265	1.0000	$306,756.42	$6,495.78
1993	20.50	$1,585,378.89	65.00	46.36	0.7132	1.0000	$1,130,671.62	$24,390.44
1992	21.50	$1,369,384.65	65.00	45.50	0.7000	1.0000	$958,528.60	$21,067.46
1991	22.50	$1,063,802.12	65.00	44.64	0.6868	1.0000	$730,632.58	$16,366.19
1990	23.50	$1,104,984.04	65.00	43.79	0.6738	1.0000	$744,498.49	$16,999.75
1989	24.50	$684,178.32	65.00	42.95	0.6608	1.0000	$452,093.18	$10,525.82
1988	25.50	$626,096.02	65.00	42.11	0.6479	1.0000	$405,660.26	$9,632.25
1987	26.50	$670,723.67	65.00	41.28	0.6351	1.0000	$425,992.55	$10,318.83
1986	27.50	$1,052,626.77	65.00	40.46	0.6225	1.0000	$655,220.07	$16,194.26
1985	28.50	$2,259,154.72	65.00	39.64	0.6099	1.0000	$1,377,771.76	$34,756.23
1984	29.50	$445,331.68	65.00	38.83	0.5974	1.0000	$266,036.36	$6,851.26
1983	30.50	$515,299.62	65.00	38.02	0.5850	1.0000	$301,448.55	$7,927.69
1982	31.50	$156,641.29	65.00	37.23	0.5727	1.0000	$89,713.04	$2,409.87
1981	32.50	$239,500.41	65.00	36.44	0.5605	1.0000	$134,251.18	$3,684.62

Generation Arrangement Report

Account: MTED 101/6-356 Overhead Conductor
Dispersion: 65.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$99,955.79	65.00	35.65	0.5485	1.0000	$54,821.84	$1,537.78
1979	34.50	$272,890.72	65.00	34.87	0.5365	1.0000	$146,414.38	$4,198.32
1978	35.50	$146,164.49	65.00	34.10	0.5247	1.0000	$76,686.63	$2,248.68
1977	36.50	$289,305.26	65.00	33.34	0.5130	1.0000	$148,401.61	$4,450.85
1976	37.50	$7,116,472.96	65.00	32.59	0.5013	1.0000	$3,567,656.31	$109,484.20
1975	38.50	$302,604.11	65.00	31.84	0.4898	1.0000	$148,229.32	$4,655.45
1974	39.50	$653,881.30	65.00	31.10	0.4784	1.0000	$312,849.39	$10,059.71
1973	40.50	$836,896.96	65.00	30.37	0.4672	1.0000	$391,013.82	$12,875.34
1972	41.50	$368,173.81	65.00	29.64	0.4561	1.0000	$167,913.58	$5,664.21
1971	42.50	$1,370,460.03	65.00	28.93	0.4451	1.0000	$609,974.05	$21,084.00
1970	43.50	$1,971,197.83	65.00	28.22	0.4342	1.0000	$855,894.51	$30,326.12
1969	44.50	$368,621.83	65.00	27.53	0.4235	1.0000	$156,102.23	$5,671.11
1968	45.50	$2,535,345.63	65.00	26.84	0.4129	1.0000	$1,046,751.45	$39,005.32
1967	46.50	$5,826,480.53	65.00	26.15	0.4024	1.0000	$2,344,380.37	$89,638.16
1966	47.50	$623,245.59	65.00	25.49	0.3921	1.0000	$244,363.23	$9,588.39
1965	48.50	$157,818.31	65.00	24.82	0.3819	1.0000	$60,267.68	$2,427.97
1964	49.50	$375,353.29	65.00	24.17	0.3719	1.0000	$139,589.30	$5,774.67
1963	50.50	$376,244.99	65.00	23.53	0.3620	1.0000	$136,198.19	$5,788.38
1962	51.50	$174,735.60	65.00	22.90	0.3523	1.0000	$61,561.84	$2,688.24
1961	52.50	$153,576.97	65.00	22.28	0.3427	1.0000	$52,637.79	$2,362.72
1960	53.50	$105,460.51	65.00	21.67	0.3334	1.0000	$35,160.27	$1,622.47
1959	54.50	$377,376.15	65.00	21.07	0.3242	1.0000	$122,335.23	$5,805.79
1958	55.50	$53,653.32	65.00	20.49	0.3152	1.0000	$16,909.78	$825.44
1957	56.50	$299,489.01	65.00	19.91	0.3063	1.0000	$91,735.76	$4,607.52
1956	57.50	$199,336.14	65.00	19.35	0.2977	1.0000	$59,334.99	$3,066.71
1955	58.50	$141,439.95	65.00	18.80	0.2892	1.0000	$40,901.73	$2,176.00
1954	59.50	$1,170,330.78	65.00	18.26	0.2809	1.0000	$328,714.12	$18,005.09
1953	60.50	$410,641.52	65.00	17.73	0.2728	1.0000	$112,034.23	$6,317.56
1952	61.50	$94,897.16	65.00	17.22	0.2649	1.0000	$25,140.22	$1,459.96
1951	62.50	$60,679.43	65.00	16.72	0.2573	1.0000	$15,611.04	$933.53
1950	63.50	$252,698.88	65.00	16.24	0.2498	1.0000	$63,119.27	$3,887.68
1949	64.50	$103,256.74	65.00	15.76	0.2425	1.0000	$25,043.06	$1,588.57
1948	65.50	$74,358.80	65.00	15.30	0.2355	1.0000	$17,508.20	$1,143.98

Generation Arrangement Report

Account: MTED 101/6-356 Overhead Conductor
Dispersion: 65.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$9,657.36	65.00	14.86	0.2286	1.0000	$2,207.87	$148.57
1946	67.50	$329.21	65.00	14.43	0.2220	1.0000	$73.07	$5.06
1945	68.50	$5,936.44	65.00	14.01	0.2155	1.0000	$1,279.51	$91.33
1944	69.50	$111.32	65.00	13.60	0.2093	1.0000	$23.30	$1.71
1943	70.50	$44,215.74	65.00	13.21	0.2033	1.0000	$8,987.35	$680.24
1942	71.50	$11,985.90	65.00	12.83	0.1974	1.0000	$2,366.24	$184.40
1941	72.50	$126,022.16	65.00	12.47	0.1918	1.0000	$24,168.79	$1,938.80
1940	73.50	$6,139.55	65.00	12.11	0.1863	1.0000	$1,143.89	$94.45
1939	74.50	$38.44	65.00	11.77	0.1811	1.0000	$6.96	$0.59
1938	75.50	$299,996.39	65.00	11.44	0.1759	1.0000	$52,778.01	$4,615.33
		$67,409,524.29	65.00	42.87	0.6595	1.0000	$44,457,600.97	$1,037,069.60

Remaining Life Depreciation Accrual

Account: MTED 101/6-35610 Clearing & R/W
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$18,717,196.78	65.83	$230,101.31	1.229358%	1.518980%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$18,717,196.78 *		$230,101.31	1.229358%	1.518980%
Average:	$18,717,196.78		$230,101.31	1.229358%	1.518980%
Grand Total:	$18,717,196.78 *		$230,101.31	1.229358%	1.518980%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-35610 Clearing & R/W
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 80 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$18,717,196.78	$3,568,784.76	0.1907	$15,148,412.02	0.8093
Computed	$18,717,196.78	$3,314,426.26	0.1771	$15,402,770.52	0.8229
Difference		$254,358.50	0.0136	($254,358.50)	-0.0136

Generation Arrangement Report

Account: MTED 101/6-35610 Clearing & R/W
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$8,278,261.87	80.00	79.50	0.9938	1.0000	$8,226,522.73	$103,478.27
2012	1.50	$1,043,962.39	80.00	78.50	0.9813	1.0000	$1,024,388.10	$13,049.53
2011	2.50	$261,029.37	80.00	77.50	0.9688	1.0000	$252,872.20	$3,262.87
2010	3.50	$904,849.90	80.00	76.50	0.9563	1.0000	$865,262.72	$11,310.62
2009	4.50	$1,575,254.93	80.00	75.50	0.9438	1.0000	$1,486,646.84	$19,690.69
2008	5.50	$606,101.49	80.00	74.50	0.9313	1.0000	$564,432.01	$7,576.27
2007	6.50	$59,111.16	80.00	73.50	0.9188	1.0000	$54,308.38	$738.89
2006	7.50	$98,194.93	80.00	72.50	0.9063	1.0000	$88,989.16	$1,227.44
2005	8.50	$456.76	80.00	71.50	0.8938	1.0000	$408.23	$5.71
2003	10.50	$1,009.96	80.00	69.50	0.8688	1.0000	$877.40	$12.62
2002	11.50	$28,153.36	80.00	68.50	0.8563	1.0000	$24,106.31	$351.92
2001	12.50	$22,925.87	80.00	67.50	0.8438	1.0000	$19,343.70	$286.57
1999	14.50	$259,725.36	80.00	65.50	0.8188	1.0000	$212,650.14	$3,246.57
1998	15.50	$418,485.03	80.00	64.50	0.8063	1.0000	$337,403.56	$5,231.06
1996	17.50	$98,927.44	80.00	62.50	0.7813	1.0000	$77,287.06	$1,236.59
1995	18.50	$220,531.23	80.00	61.50	0.7688	1.0000	$169,533.38	$2,756.64
1994	19.50	$30,392.16	80.00	60.50	0.7563	1.0000	$22,984.07	$379.90
1993	20.50	$142,149.94	80.00	59.50	0.7438	1.0000	$105,724.02	$1,776.87
1992	21.50	$13,424.89	80.00	58.50	0.7313	1.0000	$9,816.95	$167.81
1991	22.50	$4,332.76	80.00	57.50	0.7188	1.0000	$3,114.17	$54.16
1990	23.50	$55,219.46	80.00	56.50	0.7063	1.0000	$38,998.74	$690.24
1989	24.50	$2,275.30	80.00	55.50	0.6938	1.0000	$1,578.49	$28.44
1988	25.50	$72,166.64	80.00	54.50	0.6813	1.0000	$49,163.52	$902.08
1987	26.50	$16,666.90	80.00	53.50	0.6688	1.0000	$11,145.99	$208.34
1986	27.50	$34,218.39	80.00	52.50	0.6563	1.0000	$22,455.82	$427.73
1985	28.50	$188,565.83	80.00	51.50	0.6438	1.0000	$121,389.25	$2,357.07
1984	29.50	$64,342.39	80.00	50.50	0.6313	1.0000	$40,616.13	$804.28
1983	30.50	$62,598.28	80.00	49.50	0.6188	1.0000	$38,732.69	$782.48
1982	31.50	$34,352.25	80.00	48.50	0.6063	1.0000	$20,826.05	$429.40
1981	32.50	$6,790.85	80.00	47.50	0.5938	1.0000	$4,032.07	$84.89
1980	33.50	$971.86	80.00	46.50	0.5813	1.0000	$564.89	$12.15
1979	34.50	$21,925.52	80.00	45.50	0.5688	1.0000	$12,470.14	$274.07
1977	36.50	$30,111.22	80.00	43.50	0.5438	1.0000	$16,372.98	$376.39

Generation Arrangement Report

Account: MTED 101/6-35610 Clearing & R/W
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1976	37.50	$737,939.67	80.00	42.50	0.5313	1.0000	$392,030.45	$9,224.25
1975	38.50	$31,289.83	80.00	41.50	0.5188	1.0000	$16,231.60	$391.12
1974	39.50	$55,794.91	80.00	40.50	0.5063	1.0000	$28,246.17	$697.44
1973	40.50	$125,048.94	80.00	39.50	0.4938	1.0000	$61,742.91	$1,563.11
1972	41.50	$65,783.12	80.00	38.50	0.4813	1.0000	$31,658.13	$822.29
1971	42.50	$143,787.47	80.00	37.50	0.4688	1.0000	$67,400.38	$1,797.34
1970	43.50	$101,274.33	80.00	36.50	0.4563	1.0000	$46,206.41	$1,265.93
1969	44.50	$70,675.51	80.00	35.50	0.4438	1.0000	$31,362.26	$883.44
1968	45.50	$270,594.97	80.00	34.50	0.4313	1.0000	$116,694.08	$3,382.44
1967	46.50	$470,987.29	80.00	33.50	0.4188	1.0000	$197,225.93	$5,887.34
1966	47.50	$177,339.10	80.00	32.50	0.4063	1.0000	$72,044.01	$2,216.74
1965	48.50	$32,039.11	80.00	31.50	0.3938	1.0000	$12,615.40	$400.49
1964	49.50	$22,382.62	80.00	30.50	0.3813	1.0000	$8,533.37	$279.78
1963	50.50	$82,234.40	80.00	29.50	0.3688	1.0000	$30,323.94	$1,027.93
1962	51.50	$16,285.45	80.00	28.50	0.3563	1.0000	$5,801.69	$203.57
1961	52.50	$32,615.71	80.00	27.50	0.3438	1.0000	$11,211.65	$407.70
1960	53.50	$2,935.48	80.00	26.50	0.3313	1.0000	$972.38	$36.69
1959	54.50	$41,626.98	80.00	25.50	0.3188	1.0000	$13,268.60	$520.34
1958	55.50	$11,932.37	80.00	24.50	0.3063	1.0000	$3,654.29	$149.15
1957	56.50	$108,802.21	80.00	23.50	0.2938	1.0000	$31,960.65	$1,360.03
1956	57.50	$48,676.84	80.00	22.50	0.2813	1.0000	$13,690.36	$608.46
1955	58.50	$18,866.27	80.00	21.50	0.2688	1.0000	$5,070.31	$235.83
1954	59.50	$526,319.80	80.00	20.50	0.2563	1.0000	$134,869.45	$6,579.00
1953	60.50	$302,303.82	80.00	19.50	0.2438	1.0000	$73,686.56	$3,778.80
1952	61.50	$42,866.04	80.00	18.50	0.2313	1.0000	$9,912.77	$535.83
1951	62.50	$10,285.05	80.00	17.50	0.2188	1.0000	$2,249.85	$128.56
1950	63.50	$137,928.94	80.00	16.50	0.2063	1.0000	$28,447.84	$1,724.11
1949	64.50	$20,188.04	80.00	15.50	0.1938	1.0000	$3,911.43	$252.35
1948	65.50	$32,872.94	80.00	14.50	0.1813	1.0000	$5,958.22	$410.91
1947	66.50	$2,694.11	80.00	13.50	0.1688	1.0000	$454.63	$33.68
1945	68.50	$807.20	80.00	11.50	0.1438	1.0000	$116.04	$10.09
1944	69.50	$415.00	80.00	10.50	0.1313	1.0000	$54.47	$5.19
1943	70.50	$20,993.16	80.00	9.50	0.1188	1.0000	$2,492.94	$262.41

Generation Arrangement Report

Account: MTED 101/6-35610 Clearing & R/W
Dispersion: 80.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1942	71.50	$10,175.63	80.00	8.50	0.1063	1.0000	$1,081.16	$127.20
1941	72.50	$15,192.62	80.00	7.50	0.0938	1.0000	$1,424.31	$189.91
1940	73.50	$3,468.29	80.00	6.50	0.0813	1.0000	$281.80	$43.35
1938	75.50	$264,287.87	80.00	4.50	0.0563	1.0000	$14,866.19	$3,303.60
		$18,717,196.78	80.00	65.83	0.8229	1.0000	$15,402,770.52	$233,964.96

Remaining Life Depreciation Accrual

Account: MTED 101/6-358 Undergound Conductor
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 40.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$1,190,918.01	37.71	$29,947.52	2.514658%	2.651792%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($12,318.15)	0.50	($153.98)	1.250025%	
Total:	$1,190,918.01 *		$29,793.54	2.501729%	2.638157%
Average:	$1,184,758.94		$29,793.54	2.514734%	2.652624%
Grand Total:	$1,190,918.01 *		$29,793.54	2.501729%	2.638157%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-358 Undergound Conductor
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 40 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$1,190,918.01	$61,586.53	0.0517	$1,129,331.48	0.9483
Computed	$1,190,918.01	$68,169.48	0.0572	$1,122,748.53	0.9428
Difference		($6,582.95)	-0.0055	$6,582.95	0.0055

Generation Arrangement Report

Account: MTED 101/6-358 Undergound Conductor
Dispersion: 40.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$182,015.94	40.00	39.69	0.9922	1.0000	$180,602.64	$4,550.40
2012	1.50	$535,384.20	40.00	39.07	0.9767	1.0000	$522,931.16	$13,384.61
2011	2.50	$141,676.35	40.00	38.45	0.9613	1.0000	$136,195.35	$3,541.91
2008	5.50	$1,952.96	40.00	36.61	0.9153	1.0000	$1,787.58	$48.82
2007	6.50	$1,398.22	40.00	36.00	0.9001	1.0000	$1,258.53	$34.96
2005	8.50	$137,998.55	40.00	34.79	0.8698	1.0000	$120,027.85	$3,449.96
2003	10.50	$190,491.79	40.00	33.59	0.8396	1.0000	$159,945.42	$4,762.29
		$1,190,918.01	40.00	37.71	0.9428	1.0000	$1,122,748.53	$29,772.95

Remaining Life Depreciation Accrual

Account: MTED 101/6-359 Roads & Trails
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 50.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$746,971.13	13.95	$16,811.84	2.250668%	7.168727%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$746,971.13 *		$16,811.84	2.250668%	7.168727%
Average:	$746,971.13		$16,811.84	2.250668%	7.168727%
Grand Total:	$746,971.13 *		$16,811.84	2.250668%	7.168727%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-359 Roads & Trails
Scenario: Met Ed 2014 ADR Transmission
Dispersion: 50 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$746,971.13	$512,454.78	0.6860	$234,516.35	0.3140
Computed	$746,971.13	$538,573.99	0.7210	$208,397.14	0.2790
Difference		($26,119.21)	-0.0350	$26,119.21	0.0350

Generation Arrangement Report

Account: MTED 101/6-359 Roads & Trails
Dispersion: 50.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2012	1.50	$31,423.33	50.00	48.50	0.9700	1.0000	$30,480.63	$628.47
1993	20.50	$2,946.76	50.00	29.50	0.5900	1.0000	$1,738.59	$58.94
1983	30.50	$5,088.94	50.00	19.50	0.3900	1.0000	$1,984.69	$101.78
1976	37.50	$659,224.35	50.00	12.50	0.2500	1.0000	$164,806.09	$13,184.49
1975	38.50	$1,494.25	50.00	11.50	0.2300	1.0000	$343.68	$29.89
1974	39.50	$35,384.28	50.00	10.50	0.2100	1.0000	$7,430.70	$707.69
1973	40.50	$3,869.74	50.00	9.50	0.1900	1.0000	$735.25	$77.39
1972	41.50	$5,161.91	50.00	8.50	0.1700	1.0000	$877.52	$103.24
1903	110.50	$2,377.57	50.00	0.00	0.0000	0.0000	$0.00	$0.00
		$746,971.13	50.00	13.95	0.2790	1.0000	$208,397.14	$14,891.87

Remaining Life Depreciation Accrual

Account: MTED 101/6-36012 DIST Line
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$28,932,190.21	34.95	$426,318.86	1.473510%	2.861377%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($62,555.36)	0.50	($481.20)	0.769239%	
Total:	$28,932,190.21 *		$425,837.66	1.471847%	2.858147%
Average:	$28,900,912.53		$425,837.66	1.473440%	2.864160%
Grand Total:	$28,932,190.21 *		$425,837.66	1.471847%	2.858147%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-36012 DIST Line
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 65 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$28,932,190.21	$14,033,110.49	0.4850	$14,899,079.72	0.5150
Computed	$28,932,190.21	$13,376,372.07	0.4623	$15,555,818.14	0.5377
Difference		$656,738.42	0.0227	($656,738.42)	-0.0227

Generation Arrangement Report

Account: MTED 101/6-36012 DIST Line
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2011	2.50	$236,147.13	65.00	62.50	0.9615	1.0000	$227,064.55	$3,633.03
2010	3.50	$12,975.78	65.00	61.50	0.9462	1.0000	$12,277.08	$199.63
2009	4.50	$235,206.67	65.00	60.50	0.9308	1.0000	$218,923.13	$3,618.56
2007	6.50	$101,623.06	65.00	58.50	0.9000	1.0000	$91,460.75	$1,563.43
2003	10.50	$251,094.57	65.00	54.50	0.8385	1.0000	$210,533.14	$3,862.99
1998	15.50	$818,439.49	65.00	49.50	0.7615	1.0000	$623,273.15	$12,591.38
1997	16.50	$846,746.34	65.00	48.50	0.7462	1.0000	$631,803.04	$13,026.87
1996	17.50	$1,210,914.14	65.00	47.50	0.7308	1.0000	$884,898.79	$18,629.45
1995	18.50	$1,224,781.79	65.00	46.50	0.7154	1.0000	$876,190.05	$18,842.80
1994	19.50	$1,560,245.89	65.00	45.50	0.7000	1.0000	$1,092,172.12	$24,003.78
1993	20.50	$1,673,949.27	65.00	44.50	0.6846	1.0000	$1,146,011.42	$25,753.07
1992	21.50	$1,229,456.50	65.00	43.50	0.6692	1.0000	$822,790.12	$18,914.72
1991	22.50	$995,460.94	65.00	42.50	0.6538	1.0000	$650,878.31	$15,314.78
1990	23.50	$956,536.66	65.00	41.50	0.6385	1.0000	$610,711.87	$14,715.95
1989	24.50	$857,602.96	65.00	40.50	0.6231	1.0000	$534,352.61	$13,193.89
1988	25.50	$951,726.21	65.00	39.50	0.6077	1.0000	$578,356.70	$14,641.94
1987	26.50	$1,039,189.12	65.00	38.50	0.5923	1.0000	$615,519.71	$15,987.52
1986	27.50	$1,006,556.20	65.00	37.50	0.5769	1.0000	$580,705.50	$15,485.48
1985	28.50	$868,911.28	65.00	36.50	0.5615	1.0000	$487,927.10	$13,367.87
1984	29.50	$769,512.91	65.00	35.50	0.5462	1.0000	$420,272.44	$11,838.66
1983	30.50	$746,951.68	65.00	34.50	0.5308	1.0000	$396,458.97	$11,491.56
1982	31.50	$576,747.84	65.00	33.50	0.5154	1.0000	$297,246.96	$8,873.04
1981	32.50	$482,643.87	65.00	32.50	0.5000	1.0000	$241,321.94	$7,425.29
1980	33.50	$560,471.48	65.00	31.50	0.4846	1.0000	$271,613.10	$8,622.64
1979	34.50	$499,559.01	65.00	30.50	0.4692	1.0000	$234,408.46	$7,685.52
1978	35.50	$566,255.81	65.00	29.50	0.4538	1.0000	$256,993.02	$8,711.63
1977	36.50	$585,072.88	65.00	28.50	0.4385	1.0000	$256,531.96	$9,001.12
1976	37.50	$546,209.00	65.00	27.50	0.4231	1.0000	$231,088.42	$8,403.22
1975	38.50	$478,231.36	65.00	26.50	0.4077	1.0000	$194,971.25	$7,357.41
1974	39.50	$603,861.29	65.00	25.50	0.3923	1.0000	$236,899.43	$9,290.17
1973	40.50	$673,834.77	65.00	24.50	0.3769	1.0000	$253,983.87	$10,366.69
1972	41.50	$603,077.21	65.00	23.50	0.3615	1.0000	$218,035.61	$9,278.11
1971	42.50	$509,237.56	65.00	22.50	0.3462	1.0000	$176,274.54	$7,834.42

Generation Arrangement Report

Account: MTED 101/6-36012 DIST Line
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1970	43.50	$436,742.96	65.00	21.50	0.3308	1.0000	$144,461.13	$6,719.12
1969	44.50	$406,658.99	65.00	20.50	0.3154	1.0000	$128,253.99	$6,256.29
1968	45.50	$362,726.73	65.00	19.50	0.3000	1.0000	$108,818.02	$5,580.41
1967	46.50	$343,696.86	65.00	18.50	0.2846	1.0000	$97,821.41	$5,287.64
1966	47.50	$337,779.39	65.00	17.50	0.2692	1.0000	$90,940.61	$5,196.61
1965	48.50	$309,639.49	65.00	16.50	0.2538	1.0000	$78,600.79	$4,763.68
1964	49.50	$272,824.35	65.00	15.50	0.2385	1.0000	$65,058.11	$4,197.30
1963	50.50	$249,922.94	65.00	14.50	0.2231	1.0000	$55,752.04	$3,844.97
1962	51.50	$236,861.74	65.00	13.50	0.2077	1.0000	$49,194.36	$3,644.03
1961	52.50	$261,443.45	65.00	12.50	0.1923	1.0000	$50,277.59	$4,022.21
1960	53.50	$103,137.45	65.00	11.50	0.1769	1.0000	$18,247.40	$1,586.73
1959	54.50	$128,173.89	65.00	10.50	0.1615	1.0000	$20,705.01	$1,971.91
1958	55.50	$133,446.65	65.00	9.50	0.1462	1.0000	$19,503.74	$2,053.03
1957	56.50	$92,106.57	65.00	8.50	0.1308	1.0000	$12,044.71	$1,417.02
1956	57.50	$88,012.03	65.00	7.50	0.1154	1.0000	$10,155.23	$1,354.03
1955	58.50	$64,444.39	65.00	6.50	0.1000	1.0000	$6,444.44	$991.45
1954	59.50	$83,959.01	65.00	5.50	0.0846	1.0000	$7,104.22	$1,291.68
1953	60.50	$51,763.45	65.00	4.50	0.0692	1.0000	$3,583.62	$796.36
1952	61.50	$47,030.63	65.00	3.50	0.0538	1.0000	$2,532.42	$723.55
1951	62.50	$79,710.23	65.00	2.50	0.0385	1.0000	$3,065.78	$1,226.31
1950	63.50	$35,672.13	65.00	1.50	0.0231	1.0000	$823.20	$548.80
1949	64.50	$62,555.36	65.00	0.50	0.0077	1.0000	$481.20	$962.39
1948	65.50	$49,785.96	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1947	66.50	$38,497.06	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1946	67.50	$35,420.45	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1945	68.50	$23,756.40	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1944	69.50	$8,822.26	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1943	70.50	$2,530.64	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1942	71.50	$5,425.39	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1941	72.50	$14,690.00	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1940	73.50	$8,595.66	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1939	74.50	$16,059.98	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1938	75.50	$260,448.93	65.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

Account: MTED 101/6-36012 DIST Line
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1926	87.50	$618.12	65.00	0.00	0.0000	0.0000	$0.00	$0.00
		$28,932,190.21	65.00	34.95	0.5377	1.0000	$15,555,818.14	$437,962.14

Remaining Life Depreciation Accrual

Account: MTED 101/6-361 Structure/Improve
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 45.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$12,964,492.05	22.60	$314,951.35	2.429338%	4.424774%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($334,213.64)	0.50	($3,713.48)	1.111110%	
Total:	$12,964,492.05 *		$311,237.87	2.400695%	4.372603%
Average:	$12,797,385.23		$311,237.87	2.432043%	4.477726%
Grand Total:	$12,964,492.05 *		$311,237.87	2.400695%	4.372603%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-361 Structure/Improve
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 45 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$12,964,492.05	$5,846,583.26	0.4510	$7,117,908.79	0.5490
Computed	$12,964,492.05	$6,453,428.70	0.4978	$6,511,063.35	0.5022
Difference		($606,845.44)	-0.0468	$606,845.44	0.0468

Generation Arrangement Report

Account: MTED 101/6-361 Structure/Improve
Dispersion: 45.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$91,208.42	45.00	44.51	0.9891	1.0000	$90,210.31	$2,026.85
2012	1.50	$883,343.18	45.00	43.53	0.9672	1.0000	$854,396.37	$19,629.85
2011	2.50	$163,690.84	45.00	42.55	0.9455	1.0000	$154,762.12	$3,637.57
2010	3.50	$52,791.04	45.00	41.57	0.9238	1.0000	$48,766.84	$1,173.13
2009	4.50	$262,923.93	45.00	40.60	0.9022	1.0000	$237,201.02	$5,842.75
2008	5.50	$635.99	45.00	39.63	0.8806	1.0000	$560.08	$14.13
2007	6.50	$762,854.50	45.00	38.67	0.8592	1.0000	$655,468.02	$16,952.32
2006	7.50	$39,826.43	45.00	37.71	0.8379	1.0000	$33,371.27	$885.03
2005	8.50	$298,160.98	45.00	36.75	0.8167	1.0000	$243,519.80	$6,625.80
2003	10.50	$5,225.26	45.00	34.86	0.7748	1.0000	$4,048.36	$116.12
2002	11.50	$3,397.78	45.00	33.93	0.7540	1.0000	$2,561.86	$75.51
2001	12.50	$12,900.88	45.00	33.00	0.7334	1.0000	$9,461.28	$286.69
2000	13.50	$6,217.60	45.00	32.08	0.7129	1.0000	$4,432.79	$138.17
1999	14.50	$77,485.10	45.00	31.17	0.6927	1.0000	$53,672.63	$1,721.89
1998	15.50	$757,549.75	45.00	30.27	0.6726	1.0000	$509,537.20	$16,834.44
1996	17.50	$38,184.77	45.00	28.49	0.6330	1.0000	$24,172.38	$848.55
1995	18.50	$604,354.43	45.00	27.61	0.6136	1.0000	$370,815.80	$13,430.10
1994	19.50	$170,539.15	45.00	26.74	0.5943	1.0000	$101,355.24	$3,789.76
1993	20.50	$1,308,921.18	45.00	25.89	0.5753	1.0000	$752,982.82	$29,087.14
1992	21.50	$422,115.70	45.00	25.04	0.5565	1.0000	$234,900.48	$9,380.35
1991	22.50	$294,558.55	45.00	24.21	0.5379	1.0000	$158,451.87	$6,545.75
1990	23.50	$662,744.18	45.00	23.38	0.5196	1.0000	$344,375.90	$14,727.65
1989	24.50	$614,322.01	45.00	22.57	0.5016	1.0000	$308,117.59	$13,651.60
1988	25.50	$266,213.51	45.00	21.77	0.4837	1.0000	$128,772.32	$5,915.86
1987	26.50	$266,765.60	45.00	20.98	0.4662	1.0000	$124,361.08	$5,928.12
1986	27.50	$326,682.71	45.00	20.20	0.4489	1.0000	$146,651.90	$7,259.62
1985	28.50	$185,339.72	45.00	19.44	0.4319	1.0000	$80,050.35	$4,118.66
1984	29.50	$82,694.09	45.00	18.68	0.4152	1.0000	$34,330.57	$1,837.65
1983	30.50	$202,865.25	45.00	17.94	0.3987	1.0000	$80,890.25	$4,508.12
1982	31.50	$9,253.30	45.00	17.22	0.3826	1.0000	$3,540.61	$205.63
1981	32.50	$24,651.79	45.00	16.51	0.3668	1.0000	$9,043.22	$547.82
1980	33.50	$80,565.25	45.00	15.81	0.3514	1.0000	$28,308.04	$1,790.34
1979	34.50	$68,159.53	45.00	15.13	0.3362	1.0000	$22,915.39	$1,514.66

Generation Arrangement Report

Account: MTED 101/6-361 Structure/Improve
Dispersion: 45.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1978	35.50	$4,573.91	45.00	14.47	0.3214	1.0000	$1,470.28	$101.64
1977	36.50	$14,534.92	45.00	13.82	0.3071	1.0000	$4,463.13	$323.00
1976	37.50	$25,263.50	45.00	13.19	0.2931	1.0000	$7,403.80	$561.41
1975	38.50	$3,653.41	45.00	12.57	0.2794	1.0000	$1,020.81	$81.19
1974	39.50	$131,713.69	45.00	11.98	0.2663	1.0000	$35,069.20	$2,926.97
1973	40.50	$295,178.34	45.00	11.41	0.2535	1.0000	$74,834.99	$6,559.52
1972	41.50	$545,783.09	45.00	10.86	0.2412	1.0000	$131,663.43	$12,128.51
1971	42.50	$619,333.88	45.00	10.32	0.2294	1.0000	$142,076.24	$13,762.98
1970	43.50	$160,104.36	45.00	9.81	0.2180	1.0000	$34,901.93	$3,557.87
1969	44.50	$229,232.79	45.00	9.32	0.2071	1.0000	$47,475.18	$5,094.06
1968	45.50	$143,923.81	45.00	8.85	0.1967	1.0000	$28,307.41	$3,198.31
1967	46.50	$164,560.59	45.00	8.40	0.1867	1.0000	$30,727.78	$3,656.90
1966	47.50	$65,906.76	45.00	7.97	0.1772	1.0000	$11,679.60	$1,464.59
1965	48.50	$44,037.95	45.00	7.57	0.1682	1.0000	$7,406.26	$978.62
1964	49.50	$46,344.12	45.00	7.18	0.1596	1.0000	$7,395.47	$1,029.87
1963	50.50	$47,956.82	45.00	6.81	0.1514	1.0000	$7,260.46	$1,065.71
1962	51.50	$75,166.96	45.00	6.46	0.1436	1.0000	$10,794.61	$1,670.38
1961	52.50	$54,835.49	45.00	6.13	0.1362	1.0000	$7,470.84	$1,218.57
1960	53.50	$42,479.60	45.00	5.81	0.1292	1.0000	$5,486.67	$943.99
1959	54.50	$30,086.53	45.00	5.51	0.1224	1.0000	$3,682.36	$668.59
1958	55.50	$56,750.12	45.00	5.22	0.1159	1.0000	$6,576.72	$1,261.11
1957	56.50	$106,175.94	45.00	4.94	0.1097	1.0000	$11,652.16	$2,359.47
1956	57.50	$78,755.11	45.00	4.66	0.1037	1.0000	$8,163.04	$1,750.11
1955	58.50	$34,600.24	45.00	4.40	0.0977	1.0000	$3,380.14	$768.89
1954	59.50	$49,410.48	45.00	4.13	0.0918	1.0000	$4,537.75	$1,098.01
1953	60.50	$66,987.51	45.00	3.87	0.0861	1.0000	$5,764.78	$1,488.61
1952	61.50	$30,975.60	45.00	3.62	0.0805	1.0000	$2,493.33	$688.35
1951	62.50	$45,996.49	45.00	3.36	0.0747	1.0000	$3,437.91	$1,022.14
1950	63.50	$40,437.71	45.00	3.10	0.0690	1.0000	$2,789.87	$898.62
1949	64.50	$36,569.11	45.00	2.85	0.0632	1.0000	$2,312.76	$812.65
1948	65.50	$23,966.87	45.00	2.60	0.0578	1.0000	$1,386.23	$532.60
1947	66.50	$15,707.82	45.00	2.35	0.0521	1.0000	$819.16	$349.06
1946	67.50	$6,375.07	45.00	2.09	0.0465	1.0000	$296.43	$141.67

Generation Arrangement Report

Account: MTED 101/6-361 Structure/Improve
Dispersion: 45.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1945	68.50	$4,288.02	45.00	1.84	0.0409	1.0000	$175.39	$95.29
1944	69.50	$265.92	45.00	1.59	0.0354	1.0000	$9.41	$5.91
1943	70.50	$103.69	45.00	1.37	0.0305	1.0000	$3.17	$2.30
1942	71.50	$4,766.53	45.00	1.14	0.0254	1.0000	$121.02	$105.92
1941	72.50	$22,683.94	45.00	0.92	0.0204	1.0000	$462.14	$504.09
1940	73.50	$4,050.77	45.00	0.69	0.0152	1.0000	$61.69	$90.02
1939	74.50	$1,969.24	45.00	0.55	0.0122	1.0000	$24.07	$43.76
1938	75.50	$502,301.63	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1937	76.50	$4,494.55	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1936	77.50	$5.49	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1935	78.50	$514.20	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1933	80.50	$1,422.20	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1931	82.50	$2,898.93	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1930	83.50	$1,267.43	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1929	84.50	$5,511.83	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1928	85.50	$6,388.75	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1927	86.50	$3,117.19	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	87.50	$1,349.72	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1924	89.50	$2,728.95	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1923	90.50	$1,336.79	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1922	91.50	$38.82	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1912	101.50	$1,816.55	45.00	0.00	0.0000	0.0000	$0.00	$0.00
1900	113.50	$6,649.92	45.00	0.00	0.0000	0.0000	$0.00	$0.00
		$12,964,492.05	45.00	22.60	0.5022	1.0000	$6,511,063.35	$276,058.87

Remaining Life Depreciation Accrual

Account: MTED 101/6-362 Station equipment
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 58.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$204,313,883.98	41.97	$3,184,130.84	1.558451%	2.382748%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($1,596,112.69)	0.50	($13,759.59)	0.862069%	
Total:	$204,313,883.98 *		$3,170,371.25	1.551716%	2.372452%
Average:	$203,515,827.64		$3,170,371.25	1.557801%	2.386705%
Grand Total:	$204,313,883.98 *		$3,170,371.25	1.551716%	2.372452%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-362 Station equipment
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 58 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$204,313,883.98	$70,681,179.03	0.3459	$133,632,704.95	0.6541
Computed	$204,313,883.98	$56,473,958.46	0.2764	$147,839,925.52	0.7236
Difference		$14,207,220.57	0.0695	($14,207,220.57)	-0.0695

Generation Arrangement Report

Account: MTED 101/6-362 Station equipment
Dispersion: 58.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$6,844,012.56	58.00	57.55	0.9922	1.0000	$6,790,569.65	$118,000.22
2012	1.50	$19,592,631.51	58.00	56.64	0.9766	1.0000	$19,134,497.02	$337,803.99
2011	2.50	$6,425,977.02	58.00	55.75	0.9611	1.0000	$6,176,313.14	$110,792.71
2010	3.50	$12,316,461.97	58.00	54.85	0.9457	1.0000	$11,648,155.18	$212,352.79
2009	4.50	$5,136,035.92	58.00	53.96	0.9304	1.0000	$4,778,553.89	$88,552.34
2008	5.50	$8,022,303.11	58.00	53.08	0.9152	1.0000	$7,341,697.38	$138,315.57
2007	6.50	$7,198,716.31	58.00	52.20	0.9000	1.0000	$6,478,793.58	$124,115.80
2006	7.50	$3,877,899.40	58.00	51.32	0.8849	1.0000	$3,431,569.21	$66,860.33
2005	8.50	$7,268,998.17	58.00	50.45	0.8699	1.0000	$6,323,305.84	$125,327.55
2004	9.50	$1,960,894.90	58.00	49.59	0.8550	1.0000	$1,676,584.61	$33,808.53
2003	10.50	$4,126,297.92	58.00	48.73	0.8402	1.0000	$3,466,862.30	$71,143.07
2002	11.50	$2,673,748.89	58.00	47.88	0.8255	1.0000	$2,207,053.30	$46,099.12
2001	12.50	$5,436,332.32	58.00	47.03	0.8108	1.0000	$4,407,822.99	$93,729.87
2000	13.50	$1,792,477.73	58.00	46.19	0.7963	1.0000	$1,427,339.14	$30,904.79
1999	14.50	$1,942,202.69	58.00	45.35	0.7818	1.0000	$1,518,507.21	$33,486.25
1998	15.50	$3,624,186.80	58.00	44.52	0.7675	1.0000	$2,781,566.55	$62,485.98
1997	16.50	$4,790,553.34	58.00	43.69	0.7533	1.0000	$3,608,606.34	$82,595.75
1996	17.50	$1,082,487.74	58.00	42.87	0.7391	1.0000	$800,107.73	$18,663.58
1995	18.50	$4,931,953.10	58.00	42.06	0.7251	1.0000	$3,576,157.94	$85,033.67
1994	19.50	$2,512,107.71	58.00	41.25	0.7112	1.0000	$1,786,515.72	$43,312.20
1993	20.50	$7,222,905.19	58.00	40.45	0.6974	1.0000	$5,036,942.98	$124,532.85
1992	21.50	$6,370,610.96	58.00	39.65	0.6836	1.0000	$4,355,264.27	$109,838.12
1991	22.50	$5,987,457.45	58.00	38.86	0.6700	1.0000	$4,011,830.40	$103,232.03
1990	23.50	$8,782,959.00	58.00	38.08	0.6565	1.0000	$5,766,376.36	$151,430.33
1989	24.50	$4,509,964.67	58.00	37.31	0.6432	1.0000	$2,900,821.11	$77,758.01
1988	25.50	$3,007,366.60	58.00	36.54	0.6299	1.0000	$1,894,463.91	$51,851.15
1987	26.50	$3,354,112.45	58.00	35.77	0.6168	1.0000	$2,068,825.98	$57,829.53
1986	27.50	$3,338,654.27	58.00	35.02	0.6038	1.0000	$2,015,923.35	$57,563.00
1985	28.50	$3,039,723.73	58.00	34.27	0.5909	1.0000	$1,796,236.34	$52,409.03
1984	29.50	$3,525,948.84	58.00	33.53	0.5782	1.0000	$2,038,542.20	$60,792.22
1983	30.50	$2,084,826.03	58.00	32.80	0.5655	1.0000	$1,178,982.57	$35,945.28
1982	31.50	$491,606.96	58.00	32.08	0.5530	1.0000	$271,871.31	$8,475.98
1981	32.50	$1,100,510.84	58.00	31.36	0.5407	1.0000	$594,992.87	$18,974.32

Generation Arrangement Report

Account: MTED 101/6-362 Station equipment
Dispersion: 58.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$335,552.06	58.00	30.65	0.5284	1.0000	$177,307.30	$5,785.38
1979	34.50	$701,740.81	58.00	29.95	0.5163	1.0000	$362,321.49	$12,098.98
1978	35.50	$182,283.07	58.00	29.25	0.5044	1.0000	$91,935.42	$3,142.81
1977	36.50	$362,946.30	58.00	28.57	0.4925	1.0000	$178,761.38	$6,257.69
1976	37.50	$926,242.99	58.00	27.89	0.4808	1.0000	$445,370.75	$15,969.71
1975	38.50	$430,782.13	58.00	27.22	0.4693	1.0000	$202,178.39	$7,427.28
1974	39.50	$1,868,362.89	58.00	26.56	0.4579	1.0000	$855,593.80	$32,213.15
1973	40.50	$2,237,986.93	58.00	25.91	0.4467	1.0000	$999,691.04	$38,585.98
1972	41.50	$2,099,833.90	58.00	25.26	0.4356	1.0000	$914,672.68	$36,204.03
1971	42.50	$3,610,424.64	58.00	24.63	0.4247	1.0000	$1,533,354.87	$62,248.70
1970	43.50	$1,501,742.93	58.00	24.01	0.4139	1.0000	$621,614.04	$25,892.12
1969	44.50	$3,118,756.05	58.00	23.39	0.4033	1.0000	$1,257,820.42	$53,771.66
1968	45.50	$1,276,333.30	58.00	22.79	0.3929	1.0000	$501,443.22	$22,005.75
1967	46.50	$3,511,934.07	58.00	22.19	0.3826	1.0000	$1,343,651.34	$60,550.59
1966	47.50	$1,317,333.38	58.00	21.60	0.3725	1.0000	$490,660.96	$22,712.64
1965	48.50	$655,517.62	58.00	21.03	0.3625	1.0000	$237,627.35	$11,302.03
1964	49.50	$675,959.38	58.00	20.46	0.3528	1.0000	$238,445.81	$11,654.47
1963	50.50	$827,065.31	58.00	19.90	0.3431	1.0000	$283,797.51	$14,259.75
1962	51.50	$925,951.88	58.00	19.35	0.3337	1.0000	$308,985.03	$15,964.69
1961	52.50	$784,906.21	58.00	18.82	0.3244	1.0000	$254,637.34	$13,532.87
1960	53.50	$754,704.17	58.00	18.29	0.3154	1.0000	$238,005.22	$13,012.14
1959	54.50	$788,246.93	58.00	17.77	0.3064	1.0000	$241,555.14	$13,590.46
1958	55.50	$1,097,722.31	58.00	17.27	0.2977	1.0000	$326,797.70	$18,926.25
1957	56.50	$1,685,476.94	58.00	16.77	0.2892	1.0000	$487,383.20	$29,059.95
1956	57.50	$883,657.99	58.00	16.29	0.2808	1.0000	$248,121.04	$15,235.48
1955	58.50	$869,287.46	58.00	15.81	0.2726	1.0000	$236,953.54	$14,987.71
1954	59.50	$1,460,794.95	58.00	15.34	0.2646	1.0000	$386,457.23	$25,186.12
1953	60.50	$989,349.07	58.00	14.89	0.2567	1.0000	$253,988.10	$17,057.74
1952	61.50	$350,714.22	58.00	14.44	0.2490	1.0000	$87,344.05	$6,046.80
1951	62.50	$844,811.50	58.00	14.01	0.2415	1.0000	$204,062.78	$14,565.72
1950	63.50	$684,473.32	58.00	13.58	0.2342	1.0000	$160,319.47	$11,801.26
1949	64.50	$476,444.72	58.00	13.17	0.2271	1.0000	$108,183.31	$8,214.56
1948	65.50	$277,026.00	58.00	12.76	0.2201	1.0000	$60,964.86	$4,776.31

Generation Arrangement Report

Account: MTED 101/6-362 Station equipment
Dispersion: 58.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$193,138.69	58.00	12.37	0.2132	1.0000	$41,186.04	$3,329.98
1946	67.50	$52,077.61	58.00	11.98	0.2066	1.0000	$10,757.54	$897.89
1945	68.50	$18,848.45	58.00	11.60	0.2000	1.0000	$3,770.60	$324.97
1944	69.50	$12,104.17	58.00	11.23	0.1937	1.0000	$2,344.43	$208.69
1943	70.50	$79,018.86	58.00	10.87	0.1875	1.0000	$14,814.28	$1,362.39
1942	71.50	$84,903.60	58.00	10.52	0.1814	1.0000	$15,398.66	$1,463.86
1941	72.50	$236,187.95	58.00	10.17	0.1754	1.0000	$41,431.08	$4,072.21
1940	73.50	$18,931.58	58.00	9.84	0.1696	1.0000	$3,210.78	$326.41
1939	74.50	$5,503.63	58.00	9.50	0.1639	1.0000	$901.78	$94.89
1938	75.50	$10,207.55	58.00	9.18	0.1582	1.0000	$1,615.33	$175.99
1937	76.50	$44,052.66	58.00	8.86	0.1528	1.0000	$6,729.12	$759.53
1936	77.50	$2,059.58	58.00	8.55	0.1474	1.0000	$303.50	$35.51
1935	78.50	$8,287.48	58.00	8.23	0.1420	1.0000	$1,176.53	$142.89
1934	79.50	$432.17	58.00	7.93	0.1367	1.0000	$59.08	$7.45
1933	80.50	$6,014.97	58.00	7.63	0.1315	1.0000	$791.15	$103.71
1932	81.50	$1,205.39	58.00	7.33	0.1264	1.0000	$152.39	$20.78
1931	82.50	$39,975.21	58.00	7.03	0.1212	1.0000	$4,845.97	$689.23
1930	83.50	$34,913.10	58.00	6.74	0.1162	1.0000	$4,055.58	$601.95
1929	84.50	$83,798.41	58.00	6.45	0.1112	1.0000	$9,315.28	$1,444.80
1928	85.50	$39,173.36	58.00	6.15	0.1060	1.0000	$4,154.13	$675.40
1927	86.50	$209,967.91	58.00	5.86	0.1010	1.0000	$21,214.60	$3,620.14
1926	87.50	$40,528.19	58.00	5.57	0.0961	1.0000	$3,893.53	$698.76
1925	88.50	$38,578.85	58.00	5.29	0.0912	1.0000	$3,516.47	$665.15
1924	89.50	$42,260.61	58.00	4.99	0.0860	1.0000	$3,635.90	$728.63
1923	90.50	$75,148.38	58.00	4.70	0.0811	1.0000	$6,092.98	$1,295.66
1922	91.50	$4,767.06	58.00	4.42	0.0762	1.0000	$363.15	$82.19
1921	92.50	$30,041.76	58.00	4.12	0.0711	1.0000	$2,136.52	$517.96
1920	93.50	$1,635.87	58.00	3.84	0.0662	1.0000	$108.28	$28.20
1919	94.50	$691.14	58.00	3.56	0.0613	1.0000	$42.39	$11.92
1918	95.50	$1,377.19	58.00	3.28	0.0566	1.0000	$77.94	$23.74
1917	96.50	$1,561.17	58.00	2.99	0.0516	1.0000	$80.52	$26.92
1916	97.50	$76.56	58.00	2.72	0.0468	1.0000	$3.58	$1.32
1914	99.50	$660.18	58.00	2.19	0.0378	1.0000	$24.97	$11.38

Generation Arrangement Report

Account: MTED 101/6-362 Station equipment
Dispersion: 58.00 - R2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1912	101.50	$33.01	58.00	1.65	0.0285	1.0000	$0.94	$0.57
1911	102.50	$417.38	58.00	1.42	0.0245	1.0000	$10.23	$7.20
1910	103.50	$2,199.52	58.00	1.16	0.0199	1.0000	$43.81	$37.92
1907	106.50	$300.00	58.00	0.69	0.0119	1.0000	$3.57	$5.17
1906	107.50	$1,434.29	58.00	0.19	0.0033	1.0000	$4.70	$24.73
1905	108.50	$2,460.15	58.00	0.00	0.0000	0.0000	$0.00	$0.00
1900	113.50	$1,618.81	58.00	0.00	0.0000	0.0000	$0.00	$0.00
		$204,313,883.98	58.00	41.97	0.7236	1.0000	$147,839,925.52	$3,522,582.85

Remaining Life Depreciation Accrual

Account: MTED 101/6-364 Poles towers fix
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 65.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$346,857,644.42	53.28	$4,569,719.45	1.317463%	1.876922%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($2,777,956.42)	0.50	($21,368.90)	0.769231%	
Total:	$346,857,644.42 *		$4,548,350.55	1.311302%	1.868145%
Average:	$345,468,666.21		$4,548,350.55	1.316574%	1.878864%
Grand Total:	$346,857,644.42 *		$4,548,350.55	1.311302%	1.868145%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-364 Poles towers fix
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 65 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$346,857,644.42	$103,388,800.41	0.2981	$243,468,844.01	0.7019
Computed	$346,857,644.42	$62,547,884.78	0.1803	$284,309,759.64	0.8197
Difference		$40,840,915.63	0.1177	($40,840,915.63)	-0.1177

Generation Arrangement Report

Account: MTED 101/6-364 Poles towers fix
Dispersion: 65.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$9,875,032.96	65.00	64.69	0.9952	1.0000	$9,827,788.20	$151,923.58
2012	1.50	$41,842,700.40	65.00	64.07	0.9857	1.0000	$41,243,384.07	$643,733.85
2011	2.50	$12,718,571.60	65.00	63.45	0.9761	1.0000	$12,415,183.65	$195,670.33
2010	3.50	$8,081,563.91	65.00	62.83	0.9666	1.0000	$7,812,004.25	$124,331.75
2009	4.50	$9,475,697.50	65.00	62.22	0.9572	1.0000	$9,069,803.61	$145,779.96
2008	5.50	$11,407,788.08	65.00	61.60	0.9477	1.0000	$10,811,137.18	$175,504.43
2007	6.50	$6,241,999.32	65.00	60.99	0.9383	1.0000	$5,856,558.94	$96,030.76
2006	7.50	$6,890,795.15	65.00	60.37	0.9288	1.0000	$6,400,292.46	$106,012.23
2005	8.50	$7,007,515.02	65.00	59.76	0.9194	1.0000	$6,442,867.72	$107,807.92
2004	9.50	$5,037,990.03	65.00	59.15	0.9100	1.0000	$4,584,714.23	$77,507.54
2003	10.50	$4,081,737.21	65.00	58.54	0.9007	1.0000	$3,676,331.55	$62,795.96
2002	11.50	$4,077,605.54	65.00	57.94	0.8913	1.0000	$3,634,437.95	$62,732.39
2001	12.50	$7,205,283.46	65.00	57.33	0.8820	1.0000	$6,355,033.27	$110,850.51
2000	13.50	$4,895,228.71	65.00	56.72	0.8727	1.0000	$4,271,949.78	$75,311.21
1999	14.50	$6,707,790.56	65.00	56.12	0.8634	1.0000	$5,791,425.04	$103,196.78
1998	15.50	$9,843,862.90	65.00	55.52	0.8541	1.0000	$8,407,696.79	$151,444.04
1997	16.50	$7,622,805.94	65.00	54.91	0.8448	1.0000	$6,440,098.21	$117,273.94
1996	17.50	$5,483,739.57	65.00	54.31	0.8356	1.0000	$4,582,175.01	$84,365.22
1995	18.50	$8,233,542.60	65.00	53.71	0.8264	1.0000	$6,803,886.63	$126,669.89
1994	19.50	$8,918,701.74	65.00	53.11	0.8171	1.0000	$7,287,888.78	$137,210.80
1993	20.50	$9,910,879.01	65.00	52.52	0.8079	1.0000	$8,007,340.43	$152,475.06
1992	21.50	$9,725,406.67	65.00	51.92	0.7988	1.0000	$7,768,220.47	$149,621.64
1991	22.50	$13,441,696.32	65.00	51.32	0.7896	1.0000	$10,613,296.68	$206,795.33
1990	23.50	$9,822,243.22	65.00	50.73	0.7804	1.0000	$7,665,551.44	$151,111.43
1989	24.50	$10,153,463.20	65.00	50.13	0.7713	1.0000	$7,831,209.50	$156,207.13
1988	25.50	$8,599,930.89	65.00	49.54	0.7622	1.0000	$6,554,603.52	$132,306.63
1987	26.50	$8,423,649.22	65.00	48.95	0.7531	1.0000	$6,343,508.19	$129,594.60
1986	27.50	$6,814,104.84	65.00	48.36	0.7440	1.0000	$5,069,608.38	$104,832.38
1985	28.50	$5,776,107.77	65.00	47.77	0.7349	1.0000	$4,245,028.92	$88,863.20
1984	29.50	$4,128,350.69	65.00	47.18	0.7259	1.0000	$2,996,794.69	$63,513.09
1983	30.50	$4,727,410.83	65.00	46.60	0.7169	1.0000	$3,389,057.39	$72,729.40
1982	31.50	$3,252,344.00	65.00	46.02	0.7079	1.0000	$2,302,410.41	$50,036.06
1981	32.50	$2,667,049.60	65.00	45.43	0.6990	1.0000	$1,864,175.99	$41,031.53

Generation Arrangement Report

Account: MTED 101/6-364 Poles towers fix
Dispersion: 65.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$2,841,562.45	65.00	44.85	0.6900	1.0000	$1,960,784.18	$43,716.35
1979	34.50	$2,881,953.50	65.00	44.28	0.6812	1.0000	$1,963,092.27	$44,337.75
1978	35.50	$3,120,208.95	65.00	43.70	0.6723	1.0000	$2,097,747.41	$48,003.21
1977	36.50	$2,963,910.97	65.00	43.13	0.6635	1.0000	$1,966,536.43	$45,598.63
1976	37.50	$3,049,560.08	65.00	42.56	0.6547	1.0000	$1,996,571.64	$46,916.31
1975	38.50	$2,950,129.44	65.00	41.99	0.6460	1.0000	$1,905,694.60	$45,386.61
1974	39.50	$4,265,432.49	65.00	41.42	0.6373	1.0000	$2,718,174.05	$65,622.04
1973	40.50	$4,277,123.52	65.00	40.86	0.6286	1.0000	$2,688,637.24	$65,801.90
1972	41.50	$3,282,698.00	65.00	40.30	0.6200	1.0000	$2,035,202.68	$50,503.05
1971	42.50	$3,480,890.79	65.00	39.74	0.6114	1.0000	$2,128,256.68	$53,552.17
1970	43.50	$2,926,751.87	65.00	39.19	0.6029	1.0000	$1,764,464.57	$45,026.95
1969	44.50	$2,765,820.63	65.00	38.64	0.5944	1.0000	$1,643,986.16	$42,551.09
1968	45.50	$2,494,759.13	65.00	38.09	0.5859	1.0000	$1,461,798.67	$38,380.91
1967	46.50	$2,166,490.22	65.00	37.54	0.5775	1.0000	$1,251,243.92	$33,330.62
1966	47.50	$1,887,715.45	65.00	37.00	0.5692	1.0000	$1,074,509.89	$29,041.78
1965	48.50	$1,849,950.62	65.00	36.46	0.5609	1.0000	$1,037,657.29	$28,460.78
1964	49.50	$1,661,522.25	65.00	35.92	0.5527	1.0000	$918,289.84	$25,561.88
1963	50.50	$1,493,699.70	65.00	35.39	0.5445	1.0000	$813,285.83	$22,980.00
1962	51.50	$1,458,778.12	65.00	34.86	0.5364	1.0000	$782,418.65	$22,442.74
1961	52.50	$1,239,191.13	65.00	34.34	0.5283	1.0000	$654,606.98	$19,064.48
1960	53.50	$1,154,549.77	65.00	33.81	0.5202	1.0000	$600,628.29	$17,762.30
1959	54.50	$1,167,252.69	65.00	33.30	0.5122	1.0000	$597,916.52	$17,957.73
1958	55.50	$1,041,876.25	65.00	32.78	0.5043	1.0000	$525,444.39	$16,028.87
1957	56.50	$925,413.74	65.00	32.27	0.4965	1.0000	$459,422.20	$14,237.13
1956	57.50	$872,371.03	65.00	31.76	0.4886	1.0000	$426,270.56	$13,421.09
1955	58.50	$819,141.67	65.00	31.26	0.4809	1.0000	$393,899.04	$12,602.18
1954	59.50	$758,868.17	65.00	30.75	0.4731	1.0000	$359,058.10	$11,674.89
1953	60.50	$561,891.60	65.00	30.26	0.4655	1.0000	$261,564.98	$8,644.49
1952	61.50	$567,108.76	65.00	29.76	0.4579	1.0000	$259,678.40	$8,724.75
1951	62.50	$154,851.76	65.00	29.27	0.4504	1.0000	$69,740.24	$2,382.33
1950	63.50	$335,763.50	65.00	28.79	0.4429	1.0000	$148,703.34	$5,165.59
1949	64.50	$502,723.20	65.00	28.30	0.4354	1.0000	$218,908.50	$7,734.20
1948	65.50	$522,919.99	65.00	27.82	0.4281	1.0000	$223,846.60	$8,044.92

Generation Arrangement Report

Account: MTED 101/6-364 Poles towers fix
Dispersion: 65.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$308,289.26	65.00	27.35	0.4207	1.0000	$129,712.04	$4,742.91
1946	67.50	$284,603.44	65.00	26.88	0.4135	1.0000	$117,675.75	$4,378.51
1945	68.50	$164,759.31	65.00	26.41	0.4063	1.0000	$66,934.89	$2,534.76
1944	69.50	$91,326.37	65.00	25.94	0.3991	1.0000	$36,448.18	$1,405.02
1943	70.50	$473,196.14	65.00	25.48	0.3920	1.0000	$185,485.30	$7,279.94
		$346,857,644.42	65.00	53.28	0.8197	1.0000	$284,309,759.64	$5,336,271.45

Remaining Life Depreciation Accrual

Account: MTED 101/6-365 Overhead conductor
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 55.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$365,129,006.47	46.75	$6,228,296.88	1.705780%	2.138893%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($3,374,307.56)	0.50	($30,675.52)	0.909091%	
Total:	$365,129,006.47 *		$6,197,621.36	1.697379%	2.128359%
Average:	$363,441,852.69		$6,197,621.36	1.705258%	2.140762%
Grand Total:	$365,129,006.47 *		$6,197,621.36	1.697379%	2.128359%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-365 Overhead conductor
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 55 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$365,129,006.47	$73,936,495.96	0.2025	$291,192,510.51	0.7975
Computed	$365,129,006.47	$54,748,425.07	0.1499	$310,380,581.40	0.8501
Difference		$19,188,070.89	0.0526	($19,188,070.89)	-0.0526

Generation Arrangement Report

Account: MTED 101/6-365 Overhead conductor
Dispersion: 55.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$16,243,448.15	55.00	54.69	0.9943	1.0000	$16,151,655.25	$295,335.42
2012	1.50	$61,385,116.84	55.00	54.07	0.9831	1.0000	$60,346,212.69	$1,116,093.03
2011	2.50	$25,850,108.46	55.00	53.45	0.9718	1.0000	$25,121,431.37	$470,001.97
2010	3.50	$13,743,368.65	55.00	52.83	0.9606	1.0000	$13,202,056.54	$249,879.43
2009	4.50	$21,258,311.25	55.00	52.22	0.9494	1.0000	$20,182,958.43	$386,514.75
2008	5.50	$17,922,438.37	55.00	51.60	0.9383	1.0000	$16,815,734.81	$325,862.52
2007	6.50	$20,758,151.50	55.00	50.99	0.9271	1.0000	$19,245,107.51	$377,420.94
2006	7.50	$10,790,371.35	55.00	50.38	0.9160	1.0000	$9,884,061.38	$196,188.57
2005	8.50	$11,357,642.68	55.00	49.77	0.9049	1.0000	$10,277,876.37	$206,502.59
2004	9.50	$7,335,596.52	55.00	49.16	0.8939	1.0000	$6,557,117.74	$133,374.48
2003	10.50	$3,361,828.86	55.00	48.56	0.8828	1.0000	$2,967,969.86	$61,124.16
2002	11.50	$4,513,540.00	55.00	47.95	0.8718	1.0000	$3,935,051.96	$82,064.36
2001	12.50	$5,419,736.15	55.00	47.35	0.8609	1.0000	$4,665,607.51	$98,540.66
2000	13.50	$5,664,230.46	55.00	46.74	0.8499	1.0000	$4,813,962.13	$102,986.01
1999	14.50	$7,057,201.93	55.00	46.14	0.8390	1.0000	$5,920,708.52	$128,312.76
1998	15.50	$5,955,711.88	55.00	45.54	0.8280	1.0000	$4,931,561.49	$108,285.67
1997	16.50	$6,110,355.10	55.00	44.94	0.8171	1.0000	$4,993,060.83	$111,097.37
1996	17.50	$4,486,148.34	55.00	44.34	0.8063	1.0000	$3,617,036.85	$81,566.33
1995	18.50	$6,207,951.25	55.00	43.75	0.7954	1.0000	$4,937,849.39	$112,871.84
1994	19.50	$8,389,063.95	55.00	43.15	0.7846	1.0000	$6,581,974.68	$152,528.44
1993	20.50	$7,858,852.75	55.00	42.56	0.7738	1.0000	$6,081,031.41	$142,888.23
1992	21.50	$8,243,172.79	55.00	41.96	0.7630	1.0000	$6,289,530.01	$149,875.87
1991	22.50	$7,382,866.05	55.00	41.37	0.7522	1.0000	$5,553,655.98	$134,233.93
1990	23.50	$6,416,857.56	55.00	40.78	0.7415	1.0000	$4,758,207.87	$116,670.14
1989	24.50	$4,919,363.08	55.00	40.20	0.7308	1.0000	$3,595,170.03	$89,442.97
1988	25.50	$3,872,095.03	55.00	39.61	0.7202	1.0000	$2,788,577.42	$70,401.73
1987	26.50	$4,234,636.79	55.00	39.03	0.7096	1.0000	$3,004,703.38	$76,993.40
1986	27.50	$4,409,273.76	55.00	38.44	0.6990	1.0000	$3,081,936.08	$80,168.61
1985	28.50	$3,379,106.67	55.00	37.86	0.6884	1.0000	$2,326,269.56	$61,438.30
1984	29.50	$2,987,977.88	55.00	37.29	0.6779	1.0000	$2,025,661.66	$54,326.87
1983	30.50	$3,173,545.54	55.00	36.71	0.6675	1.0000	$2,118,349.07	$57,700.83
1982	31.50	$2,000,033.84	55.00	36.14	0.6571	1.0000	$1,314,241.91	$36,364.25
1981	32.50	$1,727,310.62	55.00	35.57	0.6468	1.0000	$1,117,162.11	$31,405.65

Generation Arrangement Report

Account: MTED 101/6-365 Overhead conductor
Dispersion: 55.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$1,873,569.57	55.00	35.01	0.6365	1.0000	$1,192,475.70	$34,064.90
1979	34.50	$1,532,752.63	55.00	34.44	0.6262	1.0000	$959,882.53	$27,868.23
1978	35.50	$1,452,543.14	55.00	33.88	0.6161	1.0000	$894,880.09	$26,409.88
1977	36.50	$1,559,070.20	55.00	33.33	0.6060	1.0000	$944,760.46	$28,346.73
1976	37.50	$1,677,070.25	55.00	32.78	0.5959	1.0000	$999,423.55	$30,492.19
1975	38.50	$1,427,956.46	55.00	32.23	0.5860	1.0000	$836,711.33	$25,962.84
1974	39.50	$2,477,989.48	55.00	31.68	0.5760	1.0000	$1,427,402.59	$45,054.35
1973	40.50	$2,491,987.76	55.00	31.14	0.5662	1.0000	$1,410,945.00	$45,308.87
1972	41.50	$2,292,057.40	55.00	30.60	0.5564	1.0000	$1,275,355.54	$41,673.77
1971	42.50	$2,479,126.75	55.00	30.07	0.5467	1.0000	$1,355,390.47	$45,075.03
1970	43.50	$2,155,680.36	55.00	29.54	0.5371	1.0000	$1,157,798.69	$39,194.19
1969	44.50	$1,958,753.37	55.00	29.01	0.5275	1.0000	$1,033,295.75	$35,613.70
1968	45.50	$1,744,534.55	55.00	28.49	0.5180	1.0000	$903,751.89	$31,718.81
1967	46.50	$1,870,208.66	55.00	27.98	0.5086	1.0000	$951,259.81	$34,003.79
1966	47.50	$1,348,111.57	55.00	27.46	0.4993	1.0000	$673,128.83	$24,511.12
1965	48.50	$1,170,134.71	55.00	26.95	0.4901	1.0000	$573,429.05	$21,275.18
1964	49.50	$926,142.43	55.00	26.45	0.4809	1.0000	$445,356.65	$16,838.95
1963	50.50	$1,042,903.72	55.00	25.95	0.4718	1.0000	$492,005.30	$18,961.89
1962	51.50	$916,522.52	55.00	25.45	0.4627	1.0000	$424,106.62	$16,664.05
1961	52.50	$817,012.91	55.00	24.96	0.4538	1.0000	$370,755.82	$14,854.78
1960	53.50	$694,560.54	55.00	24.47	0.4449	1.0000	$309,026.71	$12,628.37
1959	54.50	$672,726.06	55.00	23.99	0.4361	1.0000	$293,391.97	$12,231.38
1958	55.50	$644,941.82	55.00	23.51	0.4274	1.0000	$275,654.57	$11,726.21
1957	56.50	$624,554.56	55.00	23.03	0.4188	1.0000	$261,538.94	$11,355.54
1956	57.50	$461,470.37	55.00	22.56	0.4102	1.0000	$189,291.69	$8,390.37
1955	58.50	$465,515.06	55.00	22.09	0.4017	1.0000	$186,997.65	$8,463.91
1954	59.50	$437,025.74	55.00	21.63	0.3933	1.0000	$171,873.17	$7,945.92
1953	60.50	$281,477.21	55.00	21.17	0.3849	1.0000	$108,348.87	$5,117.77
1952	61.50	$198,668.21	55.00	20.72	0.3767	1.0000	$74,829.58	$3,612.15
1951	62.50	$270,438.07	55.00	20.26	0.3684	1.0000	$99,642.08	$4,917.06
1950	63.50	$170,238.40	55.00	19.82	0.3603	1.0000	$61,339.76	$3,095.24
1949	64.50	$331,488.58	55.00	19.37	0.3523	1.0000	$116,767.97	$6,027.07
1948	65.50	$266,215.78	55.00	18.93	0.3443	1.0000	$91,646.11	$4,840.29

Generation Arrangement Report

Account: MTED 101/6-365 Overhead conductor
Dispersion: 55.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$162,088.23	55.00	18.50	0.3363	1.0000	$54,512.86	$2,947.06
1946	67.50	$147,227.16	55.00	18.06	0.3284	1.0000	$48,355.61	$2,676.86
1945	68.50	$97,700.60	55.00	17.64	0.3206	1.0000	$31,326.39	$1,776.37
1944	69.50	$40,556.99	55.00	17.21	0.3129	1.0000	$12,689.76	$737.40
1943	70.50	$1,532,570.60	55.00	16.79	0.3052	1.0000	$467,740.22	$27,864.92
		$365,129,006.47	55.00	46.75	0.8501	1.0000	$310,380,581.40	$6,638,709.21

Remaining Life Depreciation Accrual

Account: MTED 101/6-36510 Clearing & R/W
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$129,000,441.71	57.45	$1,959,429.12	1.518932%	1.740643%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($111,809.97)	0.50	($860.08)	0.769234%	
Total:	$129,000,441.71 *		$1,958,569.04	1.518265%	1.739879%
Average:	$128,944,536.73		$1,958,569.04	1.518924%	1.740744%
Grand Total:	$129,000,441.71 *		$1,958,569.04	1.518265%	1.739879%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-36510 Clearing & R/W
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 65 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$129,000,441.71	$16,431,201.52	0.1274	$112,569,240.19	0.8726
Computed	$129,000,441.71	$14,983,860.17	0.1162	$114,016,581.54	0.8838
Difference		$1,447,341.35	0.0112	($1,447,341.35)	-0.0112

Generation Arrangement Report

Account: MTED 101/6-36510 Clearing & R/W
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$40,397,191.76	65.00	64.50	0.9923	1.0000	$40,086,444.13	$621,495.26
2012	1.50	$9,581,034.71	65.00	63.50	0.9769	1.0000	$9,359,933.91	$147,400.53
2011	2.50	$5,347,439.85	65.00	62.50	0.9615	1.0000	$5,141,769.09	$82,268.31
2010	3.50	$13,619,163.01	65.00	61.50	0.9462	1.0000	$12,885,823.46	$209,525.58
2009	4.50	$23,008,169.36	65.00	60.50	0.9308	1.0000	$21,415,296.10	$353,971.84
2008	5.50	$4,776,396.94	65.00	59.50	0.9154	1.0000	$4,372,240.28	$73,483.03
2007	6.50	$2,522.69	65.00	58.50	0.9000	1.0000	$2,270.42	$38.81
2006	7.50	$502,587.25	65.00	57.50	0.8846	1.0000	$444,596.41	$7,732.11
2005	8.50	$5,871,073.39	65.00	56.50	0.8692	1.0000	$5,103,317.64	$90,324.21
2003	10.50	$289,138.51	65.00	54.50	0.8385	1.0000	$242,431.52	$4,448.28
2002	11.50	$930,637.13	65.00	53.50	0.8231	1.0000	$765,985.95	$14,317.49
2001	12.50	$1,024,416.95	65.00	52.50	0.8077	1.0000	$827,413.69	$15,760.26
2000	13.50	$1,060,475.82	65.00	51.50	0.7923	1.0000	$840,223.15	$16,315.01
1999	14.50	$789,723.85	65.00	50.50	0.7769	1.0000	$613,554.68	$12,149.60
1998	15.50	$1,228,338.58	65.00	49.50	0.7615	1.0000	$935,427.07	$18,897.52
1997	16.50	$869,150.23	65.00	48.50	0.7462	1.0000	$648,519.79	$13,371.54
1996	17.50	$617,283.24	65.00	47.50	0.7308	1.0000	$451,091.60	$9,496.67
1995	18.50	$1,004,098.76	65.00	46.50	0.7154	1.0000	$718,316.81	$15,447.67
1994	19.50	$1,641,782.22	65.00	45.50	0.7000	1.0000	$1,149,247.55	$25,258.19
1993	20.50	$1,098,372.52	65.00	44.50	0.6846	1.0000	$751,962.73	$16,898.04
1992	21.50	$1,262,265.83	65.00	43.50	0.6692	1.0000	$844,747.13	$19,419.47
1991	22.50	$1,221,528.11	65.00	42.50	0.6538	1.0000	$798,691.46	$18,792.74
1990	23.50	$1,308,777.24	65.00	41.50	0.6385	1.0000	$835,603.93	$20,135.03
1989	24.50	$1,328,283.71	65.00	40.50	0.6231	1.0000	$827,622.93	$20,435.13
1988	25.50	$1,231,252.20	65.00	39.50	0.6077	1.0000	$748,222.49	$18,942.34
1987	26.50	$1,058,580.27	65.00	38.50	0.5923	1.0000	$627,005.24	$16,285.85
1986	27.50	$648,563.92	65.00	37.50	0.5769	1.0000	$374,171.49	$9,977.91
1985	28.50	$374,897.72	65.00	36.50	0.5615	1.0000	$210,519.49	$5,767.66
1984	29.50	$251,487.33	65.00	35.50	0.5462	1.0000	$137,350.77	$3,869.04
1983	30.50	$346,093.20	65.00	34.50	0.5308	1.0000	$183,695.62	$5,324.51
1982	31.50	$200,843.36	65.00	33.50	0.5154	1.0000	$103,511.58	$3,089.90
1981	32.50	$196,628.87	65.00	32.50	0.5000	1.0000	$98,314.44	$3,025.06
1980	33.50	$234,120.27	65.00	31.50	0.4846	1.0000	$113,458.28	$3,601.85

Generation Arrangement Report

Account: MTED 101/6-36510 Clearing & R/W
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1979	34.50	$190,024.02	65.00	30.50	0.4692	1.0000	$89,165.12	$2,923.45
1978	35.50	$250,510.99	65.00	29.50	0.4538	1.0000	$113,693.45	$3,854.02
1977	36.50	$249,591.37	65.00	28.50	0.4385	1.0000	$109,436.22	$3,839.87
1976	37.50	$217,645.81	65.00	27.50	0.4231	1.0000	$92,080.92	$3,348.40
1975	38.50	$126,037.32	65.00	26.50	0.4077	1.0000	$51,384.45	$1,939.04
1974	39.50	$264,472.28	65.00	25.50	0.3923	1.0000	$103,754.51	$4,068.80
1973	40.50	$273,558.19	65.00	24.50	0.3769	1.0000	$103,110.39	$4,208.59
1972	41.50	$242,676.69	65.00	23.50	0.3615	1.0000	$87,736.96	$3,733.49
1971	42.50	$188,095.19	65.00	22.50	0.3462	1.0000	$65,109.87	$2,893.77
1970	43.50	$199,854.86	65.00	21.50	0.3308	1.0000	$66,105.84	$3,074.69
1969	44.50	$167,220.44	65.00	20.50	0.3154	1.0000	$52,738.75	$2,572.62
1968	45.50	$157,352.81	65.00	19.50	0.3000	1.0000	$47,205.84	$2,420.81
1967	46.50	$147,026.94	65.00	18.50	0.2846	1.0000	$41,846.13	$2,261.95
1966	47.50	$137,922.39	65.00	17.50	0.2692	1.0000	$37,132.95	$2,121.88
1965	48.50	$112,141.95	65.00	16.50	0.2538	1.0000	$28,466.80	$1,725.26
1964	49.50	$101,255.83	65.00	15.50	0.2385	1.0000	$24,145.62	$1,557.78
1963	50.50	$105,031.57	65.00	14.50	0.2231	1.0000	$23,430.12	$1,615.87
1962	51.50	$101,482.68	65.00	13.50	0.2077	1.0000	$21,077.17	$1,561.27
1961	52.50	$112,032.35	65.00	12.50	0.1923	1.0000	$21,544.68	$1,723.57
1960	53.50	$184,164.75	65.00	11.50	0.1769	1.0000	$32,582.99	$2,833.30
1959	54.50	$219,487.04	65.00	10.50	0.1615	1.0000	$35,455.60	$3,376.72
1958	55.50	$205,720.85	65.00	9.50	0.1462	1.0000	$30,066.89	$3,164.94
1957	56.50	$154,150.38	65.00	8.50	0.1308	1.0000	$20,158.13	$2,371.54
1956	57.50	$157,112.80	65.00	7.50	0.1154	1.0000	$18,128.40	$2,417.12
1955	58.50	$114,406.64	65.00	6.50	0.1000	1.0000	$11,440.66	$1,760.10
1954	59.50	$140,496.62	65.00	5.50	0.0846	1.0000	$11,888.18	$2,161.49
1953	60.50	$94,275.28	65.00	4.50	0.0692	1.0000	$6,526.75	$1,450.39
1952	61.50	$84,341.60	65.00	3.50	0.0538	1.0000	$4,541.47	$1,297.56
1951	62.50	$142,947.05	65.00	2.50	0.0385	1.0000	$5,497.96	$2,199.19
1950	63.50	$64,472.02	65.00	1.50	0.0231	1.0000	$1,487.82	$991.88
1949	64.50	$111,809.97	65.00	0.50	0.0077	1.0000	$860.08	$1,720.15
1948	65.50	$89,249.67	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1947	66.50	$69,038.07	65.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

Account: MTED 101/6-36510 Clearing & R/W
Dispersion: 65.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1946	67.50	$63,631.42	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1945	68.50	$42,550.51	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1944	69.50	$15,821.25	65.00	0.00	0.0000	0.0000	$0.00	$0.00
1943	70.50	$380,513.31	65.00	0.00	0.0000	0.0000	$0.00	$0.00
		$129,000,441.71	65.00	57.45	0.8838	1.0000	$114,016,581.54	$1,974,455.96

Remaining Life Depreciation Accrual

Account: MTED 101/6-366 Underground condult
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 60.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$30,284,873.81	37.23	$525,668.58	1.735746%	2.686254%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($272,476.80)	0.50	($2,270.64)	0.833333%	
Total:	$30,284,873.81 *		$523,397.94	1.728249%	2.674651%
Average:	$30,148,635.41		$523,397.94	1.736058%	2.693402%
Grand Total:	$30,284,873.81 *		$523,397.94	1.728249%	2.674651%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-366 Underground conduit
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 60 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$30,284,873.81	$10,716,042.54	0.3538	$19,568,831.27	0.6462
Computed	$30,284,873.81	$11,494,847.57	0.3796	$18,790,026.24	0.6204
Difference		($778,805.03)	-0.0257	$778,805.03	0.0257

Generation Arrangement Report

Account: MTED 101/6-366 Underground conduit
Dispersion: 60.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$48,357.55	60.00	59.53	0.9921	1.0000	$47,976.41	$805.96
2012	1.50	$2,312,987.60	60.00	58.58	0.9764	1.0000	$2,258,410.32	$38,549.79
2011	2.50	$75,590.56	60.00	57.64	0.9607	1.0000	$72,623.25	$1,259.84
2010	3.50	$34,341.50	60.00	56.71	0.9451	1.0000	$32,457.34	$572.36
2009	4.50	$2,604.34	60.00	55.77	0.9296	1.0000	$2,420.89	$43.41
2008	5.50	$108,543.60	60.00	54.85	0.9141	1.0000	$99,218.30	$1,809.06
2007	6.50	$20,261.15	60.00	53.92	0.8986	1.0000	$18,207.60	$337.69
2006	7.50	$4,829.94	60.00	53.00	0.8833	1.0000	$4,266.13	$80.50
2005	8.50	$34,373.35	60.00	52.08	0.8680	1.0000	$29,835.77	$572.89
2004	9.50	$78,115.75	60.00	51.17	0.8528	1.0000	$66,613.55	$1,301.93
2003	10.50	$439,228.26	60.00	50.25	0.8376	1.0000	$367,889.61	$7,320.47
2002	11.50	$1,249,746.99	60.00	49.35	0.8225	1.0000	$1,027,943.66	$20,829.12
2001	12.50	$1,671,131.44	60.00	48.45	0.8075	1.0000	$1,349,461.65	$27,852.19
2000	13.50	$1,381,842.30	60.00	47.55	0.7926	1.0000	$1,095,221.96	$23,030.71
1999	14.50	$796,839.79	60.00	46.67	0.7778	1.0000	$619,744.92	$13,280.66
1998	15.50	$1,286,137.91	60.00	45.78	0.7630	1.0000	$981,322.61	$21,435.63
1997	16.50	$752,540.26	60.00	44.90	0.7483	1.0000	$563,143.74	$12,542.34
1996	17.50	$386,759.14	60.00	44.03	0.7338	1.0000	$283,794.18	$6,445.99
1995	18.50	$994,720.35	60.00	43.16	0.7193	1.0000	$715,496.99	$16,578.67
1994	19.50	$709,687.42	60.00	42.29	0.7049	1.0000	$500,259.78	$11,828.12
1992	21.50	$1,098,095.22	60.00	40.59	0.6765	1.0000	$742,824.32	$18,301.59
1991	22.50	$1,542,593.00	60.00	39.74	0.6624	1.0000	$1,021,795.56	$25,709.88
1989	24.50	$1,024,705.32	60.00	38.08	0.6346	1.0000	$650,273.12	$17,078.42
1988	25.50	$1,275,732.42	60.00	37.25	0.6209	1.0000	$792,042.49	$21,262.21
1986	27.50	$1,080,310.11	60.00	35.62	0.5937	1.0000	$641,432.86	$18,005.17
1985	28.50	$858,211.76	60.00	34.82	0.5804	1.0000	$498,069.92	$14,303.53
1983	30.50	$409,913.45	60.00	33.24	0.5540	1.0000	$227,086.97	$6,831.89
1982	31.50	$258,271.11	60.00	32.46	0.5410	1.0000	$139,717.65	$4,304.52
1981	32.50	$344,878.84	60.00	31.69	0.5281	1.0000	$182,139.37	$5,747.98
1980	33.50	$358,492.35	60.00	30.92	0.5154	1.0000	$184,759.41	$5,974.87
1979	34.50	$368,875.89	60.00	30.17	0.5028	1.0000	$185,467.59	$6,147.93
1978	35.50	$375,987.74	60.00	29.42	0.4903	1.0000	$184,354.11	$6,266.46
1977	36.50	$318,411.98	60.00	28.68	0.4780	1.0000	$152,194.85	$5,306.87

Generation Arrangement Report

Account: MTED 101/6-366 Underground conduit
Dispersion: 60.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1976	37.50	$200,220.80	60.00	27.95	0.4658	1.0000	$93,258.07	$3,337.01
1975	38.50	$326,678.68	60.00	27.23	0.4538	1.0000	$148,240.02	$5,444.64
1974	39.50	$551,873.19	60.00	26.51	0.4419	1.0000	$243,863.93	$9,197.89
1973	40.50	$1,260,608.36	60.00	25.81	0.4301	1.0000	$542,222.66	$21,010.14
1972	41.50	$719,301.75	60.00	25.12	0.4186	1.0000	$301,092.17	$11,988.36
1971	42.50	$489,756.50	60.00	24.43	0.4072	1.0000	$199,412.76	$8,162.61
1970	43.50	$401,908.74	60.00	23.75	0.3959	1.0000	$159,113.44	$6,698.48
1969	44.50	$379,104.07	60.00	23.09	0.3849	1.0000	$145,901.68	$6,318.40
1968	45.50	$337,500.36	60.00	22.44	0.3739	1.0000	$126,206.34	$5,625.01
1967	46.50	$820,908.41	60.00	21.79	0.3632	1.0000	$298,151.96	$13,681.81
1966	47.50	$314,916.78	60.00	21.16	0.3527	1.0000	$111,074.19	$5,248.61
1965	48.50	$192,759.46	60.00	20.54	0.3424	1.0000	$65,991.58	$3,212.66
1964	49.50	$89,303.38	60.00	19.93	0.3322	1.0000	$29,665.14	$1,488.39
1963	50.50	$106,501.00	60.00	19.34	0.3223	1.0000	$34,324.01	$1,775.02
1962	51.50	$131,123.44	60.00	18.75	0.3125	1.0000	$40,981.29	$2,185.39
1961	52.50	$138,501.46	60.00	18.18	0.3030	1.0000	$41,965.23	$2,308.36
1960	53.50	$115,227.74	60.00	17.62	0.2937	1.0000	$33,847.49	$1,920.46
1959	54.50	$94,534.84	60.00	17.08	0.2847	1.0000	$26,909.78	$1,575.58
1958	55.50	$151,043.20	60.00	16.55	0.2758	1.0000	$41,655.83	$2,517.39
1957	56.50	$142,047.37	60.00	16.03	0.2672	1.0000	$37,957.74	$2,367.46
1956	57.50	$145,856.92	60.00	15.53	0.2588	1.0000	$37,752.20	$2,430.95
1955	58.50	$135,726.49	60.00	15.04	0.2507	1.0000	$34,024.04	$2,262.11
1954	59.50	$192,246.43	60.00	14.57	0.2428	1.0000	$46,681.10	$3,204.11
1953	60.50	$38,846.78	60.00	14.11	0.2352	1.0000	$9,135.15	$647.45
1952	61.50	$99,859.43	60.00	13.67	0.2278	1.0000	$22,744.93	$1,664.32
1951	62.50	$62,754.10	60.00	13.24	0.2206	1.0000	$13,843.84	$1,045.90
1950	63.50	$39,793.91	60.00	12.82	0.2137	1.0000	$8,503.14	$663.23
1949	64.50	$40,112.04	60.00	12.42	0.2070	1.0000	$8,302.87	$668.53
1948	65.50	$16,519.99	60.00	12.03	0.2005	1.0000	$3,313.02	$275.33
1946	67.50	$11,481.88	60.00	11.30	0.1883	1.0000	$2,162.47	$191.36
1943	70.50	$834,737.92	60.00	10.30	0.1716	1.0000	$143,261.28	$13,912.30
		$30,284,873.81	60.00	37.23	0.6204	1.0000	$18,790,026.24	$504,747.90

Remaining Life Depreciation Accrual

Account: MTED 101/6-367 Undergrd conductor
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 35.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$201,130,560.96	23.70	$5,740,987.22	2.854358%	4.219500%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($2,522,869.27)	0.50	($36,040.99)	1.428571%	
Total:	$201,130,560.96 *		$5,704,946.23	2.836439%	4.193011%
Average:	$199,869,126.33		$5,704,946.23	2.854341%	4.232249%
Grand Total:	$201,130,560.96 *		$5,704,946.23	2.836439%	4.193011%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-367 Undergrd conductor
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 35 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$201,130,560.96	$65,072,091.76	0.3235	$136,058,469.20	0.6765
Computed	$201,130,560.96	$64,939,369.91	0.3229	$136,191,191.05	0.6771
Difference		$132,721.85	0.0007	($132,721.85)	-0.0007

Generation Arrangement Report

Account: MTED 101/6-367 Undergrd conductor
Dispersion: 35.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$11,843,094.83	35.00	34.51	0.9859	1.0000	$11,676,528.75	$338,374.14
2012	1.50	$24,568,395.83	35.00	33.53	0.9579	1.0000	$23,533,802.46	$701,954.17
2011	2.50	$9,033,000.89	35.00	32.55	0.9300	1.0000	$8,400,308.76	$258,085.74
2010	3.50	$7,932,666.16	35.00	31.58	0.9022	1.0000	$7,156,584.73	$226,647.60
2009	4.50	$6,058,089.71	35.00	30.61	0.8745	1.0000	$5,297,875.28	$173,088.28
2008	5.50	$7,226,398.66	35.00	29.65	0.8470	1.0000	$6,120,985.12	$206,468.53
2007	6.50	$7,324,520.80	35.00	28.69	0.8198	1.0000	$6,004,294.22	$209,272.02
2006	7.50	$12,807,291.84	35.00	27.74	0.7927	1.0000	$10,152,228.76	$365,922.62
2005	8.50	$7,984,877.11	35.00	26.80	0.7658	1.0000	$6,115,208.97	$228,139.35
2004	9.50	$7,367,881.37	35.00	25.87	0.7393	1.0000	$5,446,820.62	$210,510.90
2003	10.50	$5,297,074.59	35.00	24.95	0.7129	1.0000	$3,776,523.35	$151,344.99
2002	11.50	$3,740,839.67	35.00	24.04	0.6869	1.0000	$2,569,674.16	$106,881.13
2001	12.50	$4,447,352.81	35.00	23.14	0.6612	1.0000	$2,940,624.88	$127,067.22
2000	13.50	$4,563,695.70	35.00	22.25	0.6358	1.0000	$2,901,715.04	$130,391.31
1999	14.50	$4,628,301.73	35.00	21.38	0.6108	1.0000	$2,827,047.82	$132,237.19
1998	15.50	$7,856,763.18	35.00	20.52	0.5861	1.0000	$4,605,207.01	$224,478.95
1997	16.50	$4,717,100.26	35.00	19.66	0.5619	1.0000	$2,650,313.44	$134,774.29
1996	17.50	$2,464,207.39	35.00	18.83	0.5379	1.0000	$1,325,592.49	$70,405.93
1995	18.50	$4,587,301.85	35.00	18.01	0.5144	1.0000	$2,359,853.33	$131,065.77
1994	19.50	$5,202,565.11	35.00	17.20	0.4913	1.0000	$2,556,188.44	$148,644.72
1993	20.50	$4,097,233.72	35.00	16.40	0.4687	1.0000	$1,920,221.18	$117,063.82
1992	21.50	$4,804,094.91	35.00	15.63	0.4465	1.0000	$2,144,951.15	$137,259.85
1991	22.50	$6,867,347.51	35.00	14.87	0.4247	1.0000	$2,916,722.31	$196,209.93
1990	23.50	$6,121,610.21	35.00	14.12	0.4034	1.0000	$2,469,693.40	$174,903.15
1989	24.50	$4,584,858.96	35.00	13.39	0.3827	1.0000	$1,754,412.32	$130,995.97
1988	25.50	$3,847,940.33	35.00	12.68	0.3624	1.0000	$1,394,442.21	$109,941.15
1987	26.50	$3,447,596.72	35.00	11.99	0.3427	1.0000	$1,181,383.88	$98,502.76
1986	27.50	$2,918,335.29	35.00	11.32	0.3235	1.0000	$944,184.67	$83,381.01
1985	28.50	$2,321,005.07	35.00	10.68	0.3051	1.0000	$708,079.59	$66,314.43
1984	29.50	$1,207,885.02	35.00	10.05	0.2872	1.0000	$346,924.28	$34,511.00
1983	30.50	$942,990.05	35.00	9.45	0.2700	1.0000	$254,644.71	$26,942.57
1982	31.50	$796,128.47	35.00	8.88	0.2536	1.0000	$201,876.89	$22,746.53
1981	32.50	$727,192.70	35.00	8.32	0.2378	1.0000	$172,958.21	$20,776.93

Generation Arrangement Report

Account: MTED 101/6-367 Undergrd conductor
Dispersion: 35.00 - R3

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$800,439.86	35.00	7.80	0.2229	1.0000	$178,397.23	$22,869.71
1979	34.50	$917,139.31	35.00	7.30	0.2087	1.0000	$191,385.66	$26,203.98
1978	35.50	$767,734.45	35.00	6.84	0.1953	1.0000	$149,944.81	$21,935.27
1977	36.50	$765,863.76	35.00	6.39	0.1827	1.0000	$139,907.60	$21,881.82
1976	37.50	$595,853.47	35.00	5.98	0.1708	1.0000	$101,777.74	$17,024.38
1975	38.50	$507,462.83	35.00	5.59	0.1597	1.0000	$81,031.66	$14,498.94
1974	39.50	$902,689.41	35.00	5.22	0.1493	1.0000	$134,731.65	$25,791.13
1973	40.50	$823,586.47	35.00	4.88	0.1395	1.0000	$114,879.57	$23,531.04
1972	41.50	$598,099.10	35.00	4.56	0.1303	1.0000	$77,948.91	$17,088.55
1971	42.50	$618,919.85	35.00	4.26	0.1216	1.0000	$75,259.69	$17,683.42
1970	43.50	$297,628.87	35.00	3.97	0.1134	1.0000	$33,739.41	$8,503.68
1969	44.50	$217,266.76	35.00	3.69	0.1055	1.0000	$22,916.36	$6,207.62
1968	45.50	$242,709.36	35.00	3.43	0.0979	1.0000	$23,752.34	$6,934.55
1967	46.50	$221,592.71	35.00	3.17	0.0904	1.0000	$20,041.95	$6,331.22
1966	47.50	$94,043.04	35.00	2.91	0.0832	1.0000	$7,820.00	$2,686.94
1965	48.50	$103,950.36	35.00	2.66	0.0760	1.0000	$7,895.05	$2,970.01
1964	49.50	$26,200.95	35.00	2.40	0.0685	1.0000	$1,794.00	$748.60
1963	50.50	$798.93	35.00	2.14	0.0612	1.0000	$48.87	$22.83
1962	51.50	$71.49	35.00	1.89	0.0539	1.0000	$3.86	$2.04
1960	53.50	$290.52	35.00	1.39	0.0398	1.0000	$11.57	$8.30
1959	54.50	$71.49	35.00	1.16	0.0332	1.0000	$2.37	$2.04
1958	55.50	$1,038.30	35.00	0.95	0.0273	1.0000	$28.31	$29.67
1951	62.50	$31,331.46	35.00	0.00	0.0000	0.0000	$0.00	$0.00
1950	63.50	$37,279.89	35.00	0.00	0.0000	0.0000	$0.00	$0.00
1949	64.50	$52,986.72	35.00	0.00	0.0000	0.0000	$0.00	$0.00
1948	65.50	$14,692.58	35.00	0.00	0.0000	0.0000	$0.00	$0.00
1947	66.50	$10,799.70	35.00	0.00	0.0000	0.0000	$0.00	$0.00
1945	68.50	$137,596.76	35.00	0.00	0.0000	0.0000	$0.00	$0.00
1944	69.50	$6,784.11	35.00	0.00	0.0000	0.0000	$0.00	$0.00
		$201,130,560.96	35.00	23.70	0.6771	1.0000	$136,191,191.05	$5,738,259.71

Remaining Life Depreciation Accrual

Account: MTED 101/6-368 Line Transformers
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 42.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$391,129,266.21	32.02	$8,363,184.52	2.138215%	3.123374%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($4,656,959.85)	0.50	($55,440.00)	1.190476%	
Total:	$391,129,266.21 *		$8,307,744.52	2.124041%	3.102669%
Average:	$388,800,786.29		$8,307,744.52	2.136761%	3.129887%
Grand Total:	$391,129,266.21 *		$8,307,744.52	2.124041%	3.102669%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-368 Line Transformers
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 42 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$391,129,266.21	$123,368,014.23	0.3154	$267,761,251.98	0.6846
Computed	$391,129,266.21	$92,970,848.42	0.2377	$298,158,417.79	0.7623
Difference		$30,397,165.81	0.0777	($30,397,165.81)	-0.0777

Generation Arrangement Report

Account: MTED 101/6-368 Line Transformers
Dispersion: 42.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$11,041,835.78	42.00	41.51	0.9884	1.0000	$10,913,736.78	$262,900.85
2012	1.50	$40,288,666.16	42.00	40.58	0.9661	1.0000	$38,924,873.59	$959,253.96
2011	2.50	$10,704,952.26	42.00	39.69	0.9451	1.0000	$10,116,853.35	$254,879.82
2010	3.50	$12,915,130.46	42.00	38.84	0.9248	1.0000	$11,943,892.54	$307,503.11
2009	4.50	$18,916,710.73	42.00	38.02	0.9052	1.0000	$17,123,744.91	$450,397.87
2008	5.50	$19,985,244.56	42.00	37.23	0.8863	1.0000	$17,713,871.11	$475,839.16
2007	6.50	$23,372,454.70	42.00	36.46	0.8680	1.0000	$20,288,288.64	$556,487.02
2006	7.50	$18,400,547.17	42.00	35.71	0.8502	1.0000	$15,644,727.19	$438,108.27
2005	8.50	$25,267,313.13	42.00	34.98	0.8329	1.0000	$21,046,144.42	$601,602.69
2004	9.50	$17,615,280.31	42.00	34.27	0.8160	1.0000	$14,374,834.38	$419,411.44
2003	10.50	$10,118,058.61	42.00	33.58	0.7996	1.0000	$8,090,576.72	$240,906.16
2002	11.50	$8,338,362.96	42.00	32.91	0.7835	1.0000	$6,533,485.34	$198,532.45
2001	12.50	$9,617,819.24	42.00	32.25	0.7678	1.0000	$7,384,656.59	$228,995.70
2000	13.50	$10,107,328.60	42.00	31.60	0.7524	1.0000	$7,604,990.55	$240,650.68
1999	14.50	$7,095,993.54	42.00	30.97	0.7373	1.0000	$5,231,955.75	$168,952.23
1998	15.50	$7,151,882.95	42.00	30.35	0.7225	1.0000	$5,167,548.23	$170,282.93
1997	16.50	$7,494,767.60	42.00	29.74	0.7080	1.0000	$5,306,519.72	$178,446.85
1996	17.50	$5,658,654.74	42.00	29.14	0.6937	1.0000	$3,925,647.84	$134,729.87
1995	18.50	$7,232,034.50	42.00	28.55	0.6797	1.0000	$4,915,844.88	$172,191.30
1994	19.50	$7,459,425.48	42.00	27.97	0.6659	1.0000	$4,967,564.62	$177,605.37
1993	20.50	$6,736,272.53	42.00	27.40	0.6524	1.0000	$4,394,443.57	$160,387.44
1992	21.50	$5,680,699.77	42.00	26.84	0.6390	1.0000	$3,629,931.66	$135,254.76
1991	22.50	$7,235,142.28	42.00	26.28	0.6258	1.0000	$4,527,748.28	$172,265.29
1990	23.50	$8,896,555.42	42.00	25.74	0.6128	1.0000	$5,452,035.10	$211,822.75
1989	24.50	$8,504,571.79	42.00	25.20	0.6000	1.0000	$5,102,883.20	$202,489.80
1988	25.50	$8,619,695.51	42.00	24.67	0.5874	1.0000	$5,062,933.45	$205,230.85
1987	26.50	$7,784,468.00	42.00	24.15	0.5749	1.0000	$4,475,214.90	$185,344.48
1986	27.50	$6,875,403.20	42.00	23.63	0.5626	1.0000	$3,867,845.06	$163,700.08
1985	28.50	$4,688,141.93	42.00	23.12	0.5504	1.0000	$2,580,261.61	$111,622.43
1984	29.50	$5,796,977.75	42.00	22.61	0.5383	1.0000	$3,120,757.52	$138,023.28
1983	30.50	$3,590,405.58	42.00	22.11	0.5264	1.0000	$1,890,089.21	$85,485.85
1982	31.50	$2,818,421.75	42.00	21.62	0.5147	1.0000	$1,450,509.28	$67,105.28
1981	32.50	$2,353,141.82	42.00	21.13	0.5030	1.0000	$1,183,639.38	$56,027.19

Generation Arrangement Report

Account: MTED 101/6-368 Line Transformers
Dispersion: 42.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$2,980,357.22	42.00	20.64	0.4915	1.0000	$1,464,739.59	$70,960.89
1979	34.50	$3,337,266.74	42.00	20.16	0.4801	1.0000	$1,602,062.82	$79,458.73
1978	35.50	$4,085,096.72	42.00	19.69	0.4687	1.0000	$1,914,849.71	$97,264.21
1977	36.50	$2,899,138.30	42.00	19.22	0.4575	1.0000	$1,326,472.68	$69,027.10
1976	37.50	$1,832,359.26	42.00	18.75	0.4464	1.0000	$818,031.44	$43,627.60
1975	38.50	$1,237,332.53	42.00	18.29	0.4354	1.0000	$538,766.70	$29,460.30
1974	39.50	$3,726,375.49	42.00	17.83	0.4245	1.0000	$1,581,940.77	$88,723.23
1973	40.50	$3,210,549.46	42.00	17.38	0.4137	1.0000	$1,328,213.59	$76,441.65
1972	41.50	$2,425,530.18	42.00	16.92	0.4030	1.0000	$977,426.83	$57,750.72
1971	42.50	$1,917,365.58	42.00	16.48	0.3923	1.0000	$752,231.03	$45,651.56
1970	43.50	$1,806,757.48	42.00	16.03	0.3818	1.0000	$689,760.54	$43,018.04
1969	44.50	$1,590,531.27	42.00	15.59	0.3713	1.0000	$590,523.93	$37,869.79
1968	45.50	$1,262,444.73	42.00	15.16	0.3609	1.0000	$455,578.47	$30,058.21
1967	46.50	$455,572.82	42.00	14.72	0.3505	1.0000	$159,695.17	$10,846.97
1965	48.50	$227.62	42.00	13.86	0.3301	1.0000	$75.13	$5.42
		$391,129,266.21	42.00	32.02	0.7623	1.0000	$298,158,417.79	$9,312,601.58

Remaining Life Depreciation Accrual

Account: MTED 101/6-369 Services OH
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 42.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$70,598,384.18	32.86	$1,610,845.29	2.281703%	3.043675%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($1,008,511.38)	0.50	($12,006.09)	1.190476%	
Total:	$70,598,384.18 *		$1,598,839.20	2.264697%	3.020989%
Average:	$70,094,128.49		$1,598,839.20	2.280989%	3.050050%
Grand Total:	$70,598,384.18 *		$1,598,839.20	2.264697%	3.020989%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-369 Services OH
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 42 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$70,598,384.18	$17,674,025.07	0.2503	$52,924,359.11	0.7497
Computed	$70,598,384.18	$15,371,919.88	0.2177	$55,226,464.30	0.7823
Difference		$2,302,105.19	0.0326	($2,302,105.19)	-0.0326

Generation Arrangement Report

Account: MTED 101/6-369 Services OH
Dispersion: 42.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$2,852,945.87	42.00	41.69	0.9926	1.0000	$2,831,846.69	$67,927.28
2012	1.50	$14,400,200.47	42.00	41.07	0.9778	1.0000	$14,081,127.46	$342,861.92
2011	2.50	$2,351,665.22	42.00	40.45	0.9631	1.0000	$2,264,996.01	$55,992.03
2010	3.50	$1,736,795.25	42.00	39.84	0.9485	1.0000	$1,647,324.79	$41,352.27
2009	4.50	$4,430,664.44	42.00	39.22	0.9339	1.0000	$4,137,655.05	$105,492.01
2008	5.50	$1,717,500.35	42.00	38.61	0.9193	1.0000	$1,578,917.89	$40,892.87
2007	6.50	$920,696.16	42.00	38.00	0.9048	1.0000	$833,045.45	$21,921.34
2006	7.50	$1,256,490.76	42.00	37.39	0.8903	1.0000	$1,118,678.80	$29,916.45
2005	8.50	($22,289.08)	42.00	36.79	0.8759	1.0000	($19,522.90)	($530.69)
2004	9.50	$50,020.42	42.00	36.18	0.8615	1.0000	$43,092.98	$1,190.96
2003	10.50	$684,845.36	42.00	35.58	0.8472	1.0000	$580,173.02	$16,305.84
2002	11.50	$1,454,948.06	42.00	34.98	0.8328	1.0000	$1,211,749.48	$34,641.62
2001	12.50	$1,587,535.25	42.00	34.38	0.8186	1.0000	$1,299,512.80	$37,798.46
2000	13.50	$1,418,608.45	42.00	33.78	0.8043	1.0000	$1,141,033.54	$33,776.39
1999	14.50	$1,857,372.88	42.00	33.19	0.7901	1.0000	$1,467,559.88	$44,223.16
1998	15.50	$2,331,340.65	42.00	32.59	0.7760	1.0000	$1,809,039.27	$55,508.11
1997	16.50	$2,236,069.89	42.00	32.00	0.7618	1.0000	$1,703,542.05	$53,239.76
1996	17.50	$2,562,977.16	42.00	31.41	0.7478	1.0000	$1,916,489.96	$61,023.27
1995	18.50	$1,994,643.17	42.00	30.82	0.7338	1.0000	$1,463,571.22	$47,491.50
1994	19.50	$1,764,654.34	42.00	30.23	0.7198	1.0000	$1,270,189.74	$42,015.58
1993	20.50	$1,236,750.07	42.00	29.65	0.7059	1.0000	$873,016.36	$29,446.43
1992	21.50	$1,166,461.00	42.00	29.07	0.6921	1.0000	$807,268.48	$27,772.88
1991	22.50	$1,321,145.53	42.00	28.49	0.6783	1.0000	$896,149.92	$31,455.85
1990	23.50	$1,602,844.16	42.00	27.92	0.6646	1.0000	$1,065,326.93	$38,162.96
1989	24.50	$1,689,309.94	42.00	27.35	0.6511	1.0000	$1,099,863.06	$40,221.67
1988	25.50	$1,138,215.90	42.00	26.78	0.6376	1.0000	$725,692.98	$27,100.38
1987	26.50	$1,021,544.36	42.00	26.22	0.6242	1.0000	$637,641.19	$24,322.48
1986	27.50	$872,034.62	42.00	25.66	0.6109	1.0000	$532,733.48	$20,762.73
1985	28.50	$793,425.74	42.00	25.10	0.5977	1.0000	$474,249.46	$18,891.09
1984	29.50	$746,395.69	42.00	24.56	0.5847	1.0000	$436,385.43	$17,771.33
1983	30.50	$772,907.57	42.00	24.01	0.5717	1.0000	$441,861.07	$18,402.56
1982	31.50	$791,015.22	42.00	23.47	0.5589	1.0000	$442,068.50	$18,833.70
1981	32.50	$777,985.81	42.00	22.94	0.5462	1.0000	$424,898.55	$18,523.47

Generation Arrangement Report

Account: MTED 101/6-369 Services OH
Dispersion: 42.00 - R0.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$753,980.49	42.00	22.41	0.5336	1.0000	$402,295.35	$17,951.92
1979	34.50	$743,776.86	42.00	21.89	0.5211	1.0000	$387,578.08	$17,708.97
1978	35.50	$694,923.43	42.00	21.37	0.5088	1.0000	$353,547.28	$16,545.80
1977	36.50	$590,872.24	42.00	20.86	0.4966	1.0000	$293,401.43	$14,068.39
1976	37.50	$544,535.20	42.00	20.35	0.4845	1.0000	$263,818.33	$12,965.12
1975	38.50	$464,856.21	42.00	19.85	0.4725	1.0000	$219,657.13	$11,068.01
1974	39.50	$516,894.19	42.00	19.35	0.4607	1.0000	$238,143.20	$12,307.00
1973	40.50	$546,755.85	42.00	18.86	0.4490	1.0000	$245,517.58	$13,018.00
1972	41.50	$464,991.75	42.00	18.37	0.4375	1.0000	$203,428.71	$11,071.23
1971	42.50	$438,536.36	42.00	17.90	0.4261	1.0000	$186,852.05	$10,441.34
1970	43.50	$440,422.57	42.00	17.42	0.4148	1.0000	$182,679.73	$10,486.25
1969	44.50	$422,501.68	42.00	16.95	0.4036	1.0000	$170,531.80	$10,059.56
1968	45.50	$394,157.14	42.00	16.49	0.3926	1.0000	$154,744.33	$9,384.69
1967	46.50	$337,796.74	42.00	16.03	0.3817	1.0000	$128,933.62	$8,042.78
1966	47.50	$275,371.15	42.00	15.58	0.3709	1.0000	$102,135.30	$6,556.46
1965	48.50	$216,682.09	42.00	15.13	0.3602	1.0000	$78,057.04	$5,159.10
1964	49.50	$173,949.77	42.00	14.69	0.3497	1.0000	$60,829.19	$4,141.66
1963	50.50	$151,892.90	42.00	14.25	0.3393	1.0000	$51,530.25	$3,616.50
1962	51.50	$131,327.71	42.00	13.82	0.3289	1.0000	$43,197.46	$3,126.85
1961	52.50	$128,955.56	42.00	13.39	0.3187	1.0000	$41,099.90	$3,070.37
1960	53.50	$122,736.67	42.00	12.96	0.3086	1.0000	$37,876.29	$2,922.30
1959	54.50	$102,784.84	42.00	12.54	0.2986	1.0000	$30,689.96	$2,447.26
1958	55.50	$95,662.13	42.00	12.12	0.2887	1.0000	$27,613.06	$2,277.67
1957	56.50	$84,684.29	42.00	11.71	0.2788	1.0000	$23,612.53	$2,016.29
1956	57.50	$77,058.92	42.00	11.30	0.2691	1.0000	$20,733.14	$1,834.74
1955	58.50	$61,566.78	42.00	10.89	0.2594	1.0000	$15,968.19	$1,465.88
1954	59.50	$45,647.30	42.00	10.49	0.2498	1.0000	$11,401.01	$1,086.84
1953	60.50	$32,685.93	42.00	10.09	0.2402	1.0000	$7,850.70	$778.24
1952	61.50	$14,760.48	42.00	9.69	0.2307	1.0000	$3,404.87	$351.44
1951	62.50	$6,620.26	42.00	9.29	0.2212	1.0000	$1,464.44	$157.63
1950	63.50	$3,276.01	42.00	8.89	0.2118	1.0000	$693.73	$78.00
		$70,598,384.18	42.00	32.86	0.7823	1.0000	$55,226,464.30	$1,680,913.91

Remaining Life Depreciation Accrual

Account: MTED 101/6-369 Unground Services
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 41.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$98,458,791.81	23.86	$2,200,409.12	2.234853%	4.191419%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($1,120,878.15)	0.50	($13,669.25)	1.219513%	
Total:	$98,458,791.81 *		$2,186,739.87	2.220970%	4.165382%
Average:	$97,898,352.74		$2,186,739.87	2.233684%	4.210329%
Grand Total:	$98,458,791.81 *		$2,186,739.87	2.220970%	4.165382%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-369 Unground Services
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 41 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$98,458,791.81	$45,960,843.61	0.4668	$52,497,948.20	0.5332
Computed	$98,458,791.81	$41,164,739.80	0.4181	$57,294,052.01	0.5819
Difference		$4,796,103.81	0.0487	($4,796,103.81)	-0.0487

Generation Arrangement Report

Account: MTED 101/6-369 Unground Services
Dispersion: 41.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2008	5.50	$1,625,505.49	41.00	35.87	0.8749	1.0000	$1,422,132.65	$39,646.48
2007	6.50	$2,000,051.12	41.00	34.96	0.8526	1.0000	$1,705,186.33	$48,781.73
2006	7.50	$1,598,801.88	41.00	34.05	0.8304	1.0000	$1,327,680.10	$38,995.17
2005	8.50	($21,296.87)	41.00	33.15	0.8084	1.0000	($17,216.95)	($519.44)
2004	9.50	$11,925.99	41.00	32.25	0.7866	1.0000	$9,381.19	$290.88
2003	10.50	$1,957,392.20	41.00	31.36	0.7650	1.0000	$1,497,344.75	$47,741.27
2002	11.50	$4,023,222.91	41.00	30.49	0.7435	1.0000	$2,991,422.56	$98,127.39
2001	12.50	$4,827,011.94	41.00	29.61	0.7223	1.0000	$3,486,556.94	$117,732.00
2000	13.50	$4,867,084.44	41.00	28.75	0.7013	1.0000	$3,413,084.98	$118,709.38
1999	14.50	$5,807,132.45	41.00	27.90	0.6805	1.0000	$3,951,478.86	$141,637.38
1998	15.50	$5,576,591.19	41.00	27.05	0.6598	1.0000	$3,679,703.17	$136,014.42
1997	16.50	$4,827,031.92	41.00	26.22	0.6395	1.0000	$3,086,891.79	$117,732.49
1996	17.50	$5,607,772.54	41.00	25.39	0.6194	1.0000	$3,473,297.17	$136,774.94
1995	18.50	$4,863,313.90	41.00	24.58	0.5995	1.0000	$2,915,649.01	$118,617.41
1994	19.50	$5,969,219.97	41.00	23.78	0.5799	1.0000	$3,461,464.57	$145,590.73
1993	20.50	$5,335,054.51	41.00	22.98	0.5606	1.0000	$2,990,596.98	$130,123.28
1992	21.50	$5,033,025.48	41.00	22.20	0.5415	1.0000	$2,725,344.27	$122,756.72
1991	22.50	$5,361,154.54	41.00	21.43	0.5227	1.0000	$2,802,151.32	$130,759.87
1990	23.50	$5,762,118.88	41.00	20.67	0.5042	1.0000	$2,905,160.81	$140,539.48
1989	24.50	$4,757,342.88	41.00	19.92	0.4859	1.0000	$2,311,802.23	$116,032.75
1988	25.50	$3,492,352.48	41.00	19.19	0.4681	1.0000	$1,634,606.34	$85,179.33
1987	26.50	$2,390,642.06	41.00	18.47	0.4504	1.0000	$1,076,802.46	$58,308.34
1986	27.50	$2,066,147.73	41.00	17.76	0.4332	1.0000	$894,997.69	$50,393.85
1985	28.50	$1,676,994.53	41.00	17.06	0.4162	1.0000	$697,961.43	$40,902.31
1984	29.50	$1,309,066.20	41.00	16.38	0.3996	1.0000	$523,146.68	$31,928.44
1983	30.50	$790,189.54	41.00	15.72	0.3834	1.0000	$302,974.12	$19,272.92
1982	31.50	$642,730.46	41.00	15.07	0.3676	1.0000	$236,235.77	$15,676.35
1981	32.50	$705,828.42	41.00	14.44	0.3521	1.0000	$248,530.15	$17,215.33
1980	33.50	$703,935.45	41.00	13.82	0.3370	1.0000	$237,256.18	$17,169.16
1979	34.50	$787,433.35	41.00	13.22	0.3224	1.0000	$253,907.81	$19,205.69
1978	35.50	$644,797.29	41.00	12.64	0.3082	1.0000	$198,758.00	$15,726.76
1977	36.50	$462,258.47	41.00	12.08	0.2946	1.0000	$136,169.43	$11,274.60
1976	37.50	$459,576.81	41.00	11.54	0.2814	1.0000	$129,307.27	$11,209.19

Generation Arrangement Report

Account: MTED 101/6-369 Unground Services
Dispersion: 41.00 - R2.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1975	38.50	$422,332.69	41.00	11.01	0.2686	1.0000	$113,446.99	$10,300.80
1974	39.50	$414,985.42	41.00	10.51	0.2564	1.0000	$106,407.35	$10,121.60
1973	40.50	$448,956.13	41.00	10.03	0.2447	1.0000	$109,853.90	$10,950.15
1972	41.50	$280,327.11	41.00	9.57	0.2335	1.0000	$65,460.61	$6,837.25
1971	42.50	$189,175.30	41.00	9.14	0.2228	1.0000	$42,155.41	$4,614.03
1970	43.50	$167,312.88	41.00	8.72	0.2127	1.0000	$35,587.85	$4,080.80
1969	44.50	$152,860.23	41.00	8.33	0.2031	1.0000	$31,039.59	$3,728.30
1968	45.50	$149,924.70	41.00	7.95	0.1939	1.0000	$29,072.87	$3,656.70
1967	46.50	$82,651.71	41.00	7.60	0.1852	1.0000	$15,310.79	$2,015.90
1966	47.50	$72,713.94	41.00	7.26	0.1770	1.0000	$12,872.79	$1,773.51
1965	48.50	$58,402.02	41.00	6.94	0.1692	1.0000	$9,883.10	$1,424.44
1964	49.50	$17,246.36	41.00	6.64	0.1618	1.0000	$2,791.23	$420.64
1963	50.50	$8,580.03	41.00	6.34	0.1547	1.0000	$1,327.75	$209.27
1962	51.50	$11,208.16	41.00	6.07	0.1481	1.0000	$1,659.41	$273.37
1961	52.50	$7,970.39	41.00	5.80	0.1415	1.0000	$1,127.95	$194.40
1960	53.50	$10,447.20	41.00	5.54	0.1352	1.0000	$1,412.67	$254.81
1959	54.50	$9,434.45	41.00	5.30	0.1292	1.0000	$1,218.76	$230.11
1958	55.50	$6,720.49	41.00	5.05	0.1232	1.0000	$828.05	$163.91
1957	56.50	$9,284.40	41.00	4.82	0.1175	1.0000	$1,090.78	$226.45
1956	57.50	$5,793.20	41.00	4.58	0.1117	1.0000	$647.34	$141.30
1955	58.50	$4,201.42	41.00	4.36	0.1063	1.0000	$446.52	$102.47
1954	59.50	$2,829.91	41.00	4.13	0.1007	1.0000	$284.98	$69.02
1953	60.50	$1,453.15	41.00	3.91	0.0955	1.0000	$138.75	$35.44
1952	61.50	$1,356.03	41.00	3.69	0.0900	1.0000	$122.09	$33.07
1951	62.50	$619.42	41.00	3.47	0.0847	1.0000	$52.45	$15.11
1950	63.50	$360.43	41.00	3.26	0.0795	1.0000	$28.65	$8.79
1949	64.50	$234.49	41.00	3.03	0.0740	1.0000	$17.35	$5.72
		$98,458,791.81	41.00	23.86	0.5819	1.0000	$57,294,052.01	$2,401,433.95

Remaining Life Depreciation Accrual

Account: MTED-101/6-370
Scenario: Met Ed 2014 ADR Dist - Meters
Dispersion: 24.00 - O2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$65,903,176.77	19.69	$2,761,270.76	4.189890%	5.079869%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($2,270,394.51)	0.50	($47,299.89)	2.083334%	
Total:	$65,903,176.77 *		$2,713,970.87	4.118118%	4.992852%
Average:	$64,767,979.52		$2,713,970.87	4.190297%	5.099347%
Grand Total:	$65,903,176.77 *		$2,713,970.87	4.118118%	4.992852%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED-101/6-370
Scenario: Met Ed 2014 ADR Dist - Meters
Dispersion: 24 - O2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$65,903,176.77	$11,546,048.73	0.1752	$54,357,128.04	0.8248
Computed	$65,903,176.77	$11,847,337.45	0.1798	$54,055,839.32	0.8202
Difference		($301,288.72)	-0.0046	$301,288.72	0.0046

Generation Arrangement Report

Account: MTED-101/6-370
Dispersion: 24.00 - O2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$8,848,226.99	24.00	23.78	0.9908	1.0000	$8,767,151.88	$368,676.12
2012	1.50	$8,416,842.58	24.00	23.34	0.9726	1.0000	$8,186,262.05	$350,701.77
2011	2.50	$1,127,173.66	24.00	22.91	0.9545	1.0000	$1,075,916.13	$46,965.57
2010	3.50	$2,951,328.45	24.00	22.48	0.9366	1.0000	$2,764,210.02	$122,972.02
2009	4.50	$2,433,460.93	24.00	22.05	0.9188	1.0000	$2,235,905.55	$101,394.21
2008	5.50	$2,699,098.84	24.00	21.63	0.9012	1.0000	$2,432,423.31	$112,462.45
2007	6.50	$1,396,609.92	24.00	21.21	0.8838	1.0000	$1,234,280.45	$58,192.08
2006	7.50	$3,053,952.97	24.00	20.80	0.8665	1.0000	$2,646,313.44	$127,248.04
2005	8.50	$1,986,073.50	24.00	20.39	0.8495	1.0000	$1,687,153.92	$82,753.06
2004	9.50	$2,372,851.01	24.00	19.98	0.8327	1.0000	$1,975,817.47	$98,868.79
2003	10.50	$1,872,378.74	24.00	19.59	0.8161	1.0000	$1,528,104.09	$78,015.78
2002	11.50	$1,749,816.42	24.00	19.20	0.7998	1.0000	$1,399,573.18	$72,909.02
2001	12.50	$1,804,404.77	24.00	18.81	0.7839	1.0000	$1,414,406.25	$75,183.53
2000	13.50	$2,161,121.37	24.00	18.44	0.7682	1.0000	$1,660,184.11	$90,046.72
1999	14.50	$1,772,454.00	24.00	18.07	0.7529	1.0000	$1,334,510.78	$73,852.25
1998	15.50	$4,537,026.80	24.00	17.71	0.7380	1.0000	$3,348,493.35	$189,042.78
1997	16.50	$955,019.41	24.00	17.37	0.7236	1.0000	$691,054.01	$39,792.48
1996	17.50	$576,094.20	24.00	17.03	0.7097	1.0000	$408,830.99	$24,003.93
1995	18.50	$1,126,010.93	24.00	16.71	0.6963	1.0000	$784,022.23	$46,917.12
1994	19.50	$760,568.88	24.00	16.40	0.6835	1.0000	$519,852.52	$31,690.37
1993	20.50	$1,035,340.55	24.00	16.11	0.6714	1.0000	$695,128.96	$43,139.19
1992	21.50	$822,430.48	24.00	15.84	0.6600	1.0000	$542,835.25	$34,267.94
1991	22.50	$832,099.64	24.00	15.59	0.6495	1.0000	$540,411.45	$34,670.82
1990	23.50	$1,136,671.93	24.00	15.35	0.6397	1.0000	$727,172.10	$47,361.33
1989	24.50	$713,835.80	24.00	15.14	0.6309	1.0000	$450,369.68	$29,743.16
1988	25.50	$662,629.56	24.00	14.95	0.6230	1.0000	$412,833.17	$27,609.57
1987	26.50	$1,008,318.95	24.00	14.79	0.6161	1.0000	$621,189.32	$42,013.29
1986	27.50	$776,954.88	24.00	14.64	0.6101	1.0000	$473,992.02	$32,373.12
1985	28.50	$469,626.97	24.00	14.52	0.6049	1.0000	$284,072.88	$19,567.79
1984	29.50	$392,972.90	24.00	14.41	0.6005	1.0000	$235,968.05	$16,373.87
1983	30.50	$290,639.17	24.00	14.32	0.5967	1.0000	$173,427.14	$12,109.97
1982	31.50	$341,639.55	24.00	14.24	0.5934	1.0000	$202,729.49	$14,234.98
1981	32.50	$145,577.04	24.00	14.17	0.5904	1.0000	$85,948.55	$6,065.71

Generation Arrangement Report

Account: MTED-101/6-370
Dispersion: 24.00 - O2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$287,543.12	24.00	14.10	0.5875	1.0000	$168,944.94	$11,980.96
1979	34.50	$421,955.02	24.00	14.03	0.5845	1.0000	$246,646.94	$17,581.46
1978	35.50	$406,030.30	24.00	13.95	0.5812	1.0000	$235,987.86	$16,917.93
1977	36.50	$335,477.08	24.00	13.86	0.5774	1.0000	$193,714.28	$13,978.21
1976	37.50	$266,358.10	24.00	13.75	0.5731	1.0000	$152,644.30	$11,098.25
1975	38.50	$259,420.27	24.00	13.63	0.5681	1.0000	$147,365.67	$10,809.18
1974	39.50	$307,681.12	24.00	13.50	0.5623	1.0000	$173,016.84	$12,820.05
1973	40.50	$345,886.27	24.00	13.34	0.5557	1.0000	$192,200.18	$14,411.93
1972	41.50	$313,398.42	24.00	13.16	0.5482	1.0000	$171,810.36	$13,058.27
1971	42.50	$426,945.07	24.00	12.96	0.5399	1.0000	$230,511.97	$17,789.38
1970	43.50	$261,672.41	24.00	12.74	0.5308	1.0000	$138,882.70	$10,903.02
1969	44.50	$160,123.28	24.00	12.50	0.5208	1.0000	$83,384.80	$6,671.80
1968	45.50	$145,665.34	24.00	12.24	0.5100	1.0000	$74,289.99	$6,069.39
1967	46.50	$106,874.17	24.00	11.96	0.4985	1.0000	$53,273.31	$4,453.09
1966	47.50	$98,022.14	24.00	11.67	0.4862	1.0000	$47,653.88	$4,084.26
1965	48.50	$80,598.21	24.00	11.36	0.4731	1.0000	$38,134.99	$3,358.26
1964	49.50	$57,874.46	24.00	11.03	0.4595	1.0000	$26,593.52	$2,411.44
1963	50.50	$49,649.02	24.00	10.69	0.4452	1.0000	$22,106.12	$2,068.71
1962	51.50	$65,634.94	24.00	10.33	0.4304	1.0000	$28,252.19	$2,734.79
1961	52.50	$40,448.48	24.00	9.96	0.4151	1.0000	$16,788.73	$1,685.35
1960	53.50	$71,656.74	24.00	9.58	0.3992	1.0000	$28,604.62	$2,985.70
1959	54.50	$31,701.32	24.00	9.19	0.3828	1.0000	$12,136.81	$1,320.89
1958	55.50	$13,122.26	24.00	8.79	0.3661	1.0000	$4,803.82	$546.76
1957	56.50	$14,944.08	24.00	8.37	0.3489	1.0000	$5,214.18	$622.67
1956	57.50	$5,812.36	24.00	7.95	0.3314	1.0000	$1,926.18	$242.18
1955	58.50	$17,249.41	24.00	7.52	0.3135	1.0000	$5,407.95	$718.73
1954	59.50	$10,220.26	24.00	7.09	0.2953	1.0000	$3,018.20	$425.84
1953	60.50	$7,901.59	24.00	6.64	0.2768	1.0000	$2,187.38	$329.23
1952	61.50	$13,424.90	24.00	6.19	0.2581	1.0000	$3,464.60	$559.37
1951	62.50	$7,499.68	24.00	5.74	0.2391	1.0000	$1,792.93	$312.49
1950	63.50	$2,234.11	24.00	5.28	0.2198	1.0000	$491.16	$93.09
1949	64.50	$1,739.27	24.00	4.81	0.2004	1.0000	$348.56	$72.47
1948	65.50	$2,543.66	24.00	4.34	0.1808	1.0000	$459.83	$105.99

Generation Arrangement Report

Account: MTED-101/6-370
Dispersion: 24.00 - O2

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1947	66.50	$2,243.94	24.00	3.86	0.1610	1.0000	$361.20	$93.50
1946	67.50	$1,109.93	24.00	3.38	0.1410	1.0000	$156.49	$46.25
1945	68.50	$1,039.09	24.00	2.90	0.1209	1.0000	$125.59	$43.30
1944	69.50	$332.50	24.00	2.41	0.1006	1.0000	$33.46	$13.85
1943	70.50	$31,892.66	24.00	1.93	0.0802	1.0000	$2,559.01	$1,328.86
		$65,903,176.77	24.00	19.69	0.8202	1.0000	$54,055,839.32	$2,745,965.70

Remaining Life Depreciation Accrual

Account: MTED 101/6-371 Inst on cust prem
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 24.00 - O1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$3,819,894.22	16.38	$121,567.69	3.182488%	6.105248%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($133,420.45)	0.50	($2,779.59)	2.083331%	
Total:	$3,819,894.22 *		$118,788.10	3.109722%	5.965654%
Average:	$3,753,184.00		$118,788.10	3.164995%	6.172446%
Grand Total:	$3,819,894.22 *		$118,788.10	3.109722%	5.965654%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-371 Inst on cust prem
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 24 - O1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$3,819,894.22	$1,828,694.20	0.4787	$1,991,200.02	0.5213
Computed	$3,819,894.22	$1,212,919.59	0.3175	$2,606,974.63	0.6825
Difference		$615,774.61	0.1612	($615,774.61)	-0.1612

Generation Arrangement Report

Account: MTED 101/6-371 Inst on cust prem
Dispersion: 24.00 - O1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$61,422.97	24.00	23.75	0.9896	1.0000	$60,783.15	$2,559.29
2012	1.50	$383,644.70	24.00	23.25	0.9688	1.0000	$371,655.81	$15,985.20
2011	2.50	$122,536.51	24.00	22.75	0.9479	1.0000	$116,154.40	$5,105.69
2010	3.50	$111,006.24	24.00	22.25	0.9271	1.0000	$102,912.04	$4,625.26
2009	4.50	$63,572.17	24.00	21.75	0.9063	1.0000	$57,612.28	$2,648.84
2008	5.50	$76,244.37	24.00	21.25	0.8854	1.0000	$67,508.04	$3,176.85
2007	6.50	$51,764.15	24.00	20.75	0.8646	1.0000	$44,754.42	$2,156.84
2006	7.50	$185,453.68	24.00	20.25	0.8438	1.0000	$156,476.54	$7,727.24
2005	8.50	$159,358.11	24.00	19.75	0.8229	1.0000	$131,138.45	$6,639.92
2004	9.50	$221,987.78	24.00	19.25	0.8021	1.0000	$178,052.70	$9,249.49
2003	10.50	$51,832.24	24.00	18.75	0.7813	1.0000	$40,493.94	$2,159.68
2002	11.50	$24,706.97	24.00	18.25	0.7604	1.0000	$18,787.59	$1,029.46
2001	12.50	$49,205.48	24.00	17.75	0.7396	1.0000	$36,391.55	$2,050.23
2000	13.50	$50,929.37	24.00	17.25	0.7188	1.0000	$36,605.49	$2,122.06
1999	14.50	$58,052.85	24.00	16.75	0.6979	1.0000	$40,516.05	$2,418.87
1998	15.50	$298,911.90	24.00	16.25	0.6771	1.0000	$202,388.27	$12,454.66
1997	16.50	$92,766.23	24.00	15.75	0.6563	1.0000	$60,877.84	$3,865.26
1996	17.50	$143,392.96	24.00	15.25	0.6354	1.0000	$91,114.28	$5,974.71
1995	18.50	$156,216.06	24.00	14.75	0.6146	1.0000	$96,007.79	$6,509.00
1994	19.50	$140,552.09	24.00	14.25	0.5938	1.0000	$83,452.81	$5,856.34
1993	20.50	$375,806.12	24.00	13.75	0.5729	1.0000	$215,305.59	$15,658.59
1992	21.50	$226,742.59	24.00	13.25	0.5521	1.0000	$125,180.81	$9,447.61
1991	22.50	$190,074.11	24.00	12.75	0.5313	1.0000	$100,976.87	$7,919.75
1990	23.50	$152,371.35	24.00	12.25	0.5104	1.0000	$77,772.88	$6,348.81
1989	24.50	$51,744.57	24.00	11.75	0.4896	1.0000	$25,333.28	$2,156.02
1988	25.50	$18,955.86	24.00	11.25	0.4688	1.0000	$8,885.56	$789.83
1987	26.50	$13,973.37	24.00	10.75	0.4479	1.0000	$6,258.91	$582.22
1986	27.50	$16,426.93	24.00	10.25	0.4271	1.0000	$7,015.67	$684.46
1985	28.50	$21,752.74	24.00	9.75	0.4063	1.0000	$8,837.05	$906.36
1984	29.50	$15,604.80	24.00	9.25	0.3854	1.0000	$6,014.35	$650.20
1983	30.50	$14,107.60	24.00	8.75	0.3646	1.0000	$5,143.40	$587.82
1982	31.50	$14,483.03	24.00	8.25	0.3438	1.0000	$4,978.54	$603.46
1981	32.50	$17,870.03	24.00	7.75	0.3229	1.0000	$5,770.53	$744.58

Generation Arrangement Report

Account: MTED 101/6-371 Inst on cust prem
Dispersion: 24.00 - O1

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$13,499.84	24.00	7.25	0.3021	1.0000	$4,078.08	$562.49
1979	34.50	$9,640.97	24.00	6.75	0.2813	1.0000	$2,711.52	$401.71
1978	35.50	$5,999.57	24.00	6.25	0.2604	1.0000	$1,562.39	$249.98
1977	36.50	$5,169.93	24.00	5.75	0.2396	1.0000	$1,238.63	$215.41
1976	37.50	$3,866.78	24.00	5.25	0.2188	1.0000	$845.86	$161.12
1975	38.50	$3,304.50	24.00	4.75	0.1979	1.0000	$654.02	$137.69
1974	39.50	$7,956.32	24.00	4.25	0.1771	1.0000	$1,408.93	$331.51
1973	40.50	$10,106.35	24.00	3.75	0.1563	1.0000	$1,579.12	$421.10
1972	41.50	$10,603.41	24.00	3.25	0.1354	1.0000	$1,435.88	$441.81
1970	43.50	$1,758.06	24.00	2.25	0.0938	1.0000	$164.82	$73.25
1966	47.50	$13,299.15	24.00	0.25	0.0104	1.0000	$138.53	$554.13
1965	48.50	$23,762.02	24.00	0.00	0.0000	0.0000	$0.00	$0.00
1964	49.50	$19,512.32	24.00	0.00	0.0000	0.0000	$0.00	$0.00
1963	50.50	$42,394.85	24.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	51.50	$15,550.22	24.00	0.00	0.0000	0.0000	$0.00	$0.00
		$3,819,894.22	24.00	16.38	0.6825	1.0000	$2,606,974.63	$154,944.78

Remaining Life Depreciation Accrual

Account: MTED 101/6-371 Meter Socket dvc 125
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 25.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$412,207.74	8.52	$13,283.73	3.222582%	11.732449%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$412,207.74 *		$13,283.73	3.222582%	11.732449%
Average:	$412,207.74		$13,283.73	3.222582%	11.732449%
Grand Total:	$412,207.74 *		$13,283.73	3.222582%	11.732449%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-371 Meter Socket dvc 125
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 25 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$412,207.74	$298,985.58	0.7253	$113,222.16	0.2747
Computed	$412,207.74	$271,671.77	0.6591	$140,535.97	0.3409
Difference		$27,313.81	0.0663	($27,313.81)	-0.0663

Generation Arrangement Report

Account: MTED 101/6-371 Meter Socket dvc 125
Dispersion: 25.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1999	14.50	$413.75	25.00	10.50	0.4200	1.0000	$173.78	$16.55
1998	15.50	$8,805.95	25.00	9.50	0.3800	1.0000	$3,346.26	$352.24
1997	16.50	$402,988.04	25.00	8.50	0.3400	1.0000	$137,015.93	$16,119.52
		$412,207.74	25.00	8.52	0.3409	1.0000	$140,535.97	$16,488.31

Remaining Life Depreciation Accrual

Account: MTED 101/6-371 Surge Suppression 2
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 10.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$276,707.92	0.00	$0.00	0.000000%	
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$276,707.92 *		$0.00	0.000000%	0.000000%
Average:	$276,707.92		$0.00	0.000000%	0.000000%
Grand Total:	$276,707.92 *		$0.00	0.000000%	

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-371 Surge Suppression 2
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 10 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$276,707.92	$276,707.92	1.0000	$0.00	0.0000
Computed	$276,707.92	$276,707.92	1.0000	$0.00	0.0000
Difference		$0.00	0.0000	$0.00	0.0000

Generation Arrangement Report

Account: MTED 101/6-371 Surge Suppression 2
Dispersion: 10.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1998	15.50	$21,188.73	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1997	16.50	$255,519.19	10.00	0.00	0.0000	0.0000	$0.00	$0.00
		$276,707.92	0.00	0.00	0.0000	1.0000	$0.00	$0.00

Remaining Life Depreciation Accrual

Account: MTED 101/6-373 Street Lighting
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 34.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$12,229,687.55	27.87	$339,160.20	2.773253%	3.588239%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($242,565.38)	0.50	($3,567.14)	1.470589%	
Total:	$12,229,687.55 *		$335,593.06	2.744085%	3.550499%
Average:	$12,108,404.86		$335,593.06	2.771571%	3.596650%
Grand Total:	$12,229,687.55 *		$335,593.06	2.744085%	3.550499%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-373 Street Lighting
Scenario: Met Ed 2014 ADR Distribution
Dispersion: 34 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$12,229,687.55	$2,777,691.61	0.2271	$9,451,995.94	0.7729
Computed	$12,229,687.55	$2,205,363.90	0.1803	$10,024,323.65	0.8197
Difference		$572,327.71	0.0468	($572,327.71)	-0.0468

Generation Arrangement Report

Account: MTED 101/6-373 Street Lighting
Dispersion: 34.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$822,651.12	34.00	33.57	0.9874	1.0000	$812,316.16	$24,195.62
2012	1.50	$1,478,251.71	34.00	32.81	0.9651	1.0000	$1,426,627.59	$43,477.99
2011	2.50	$1,112,284.31	34.00	32.13	0.9449	1.0000	$1,051,038.30	$32,714.24
2010	3.50	$521,811.86	34.00	31.49	0.9263	1.0000	$483,361.80	$15,347.41
2009	4.50	$407,441.28	34.00	30.90	0.9089	1.0000	$370,312.58	$11,983.57
2008	5.50	$379,059.21	34.00	30.34	0.8924	1.0000	$338,266.55	$11,148.80
2007	6.50	$265,192.35	34.00	29.81	0.8767	1.0000	$232,498.07	$7,799.77
2006	7.50	$668,460.43	34.00	29.30	0.8617	1.0000	$576,038.75	$19,660.60
2005	8.50	$452,554.85	34.00	28.81	0.8474	1.0000	$383,486.08	$13,310.44
2004	9.50	$570,406.09	34.00	28.34	0.8336	1.0000	$475,467.99	$16,776.65
2003	10.50	$311,635.38	34.00	27.89	0.8202	1.0000	$255,613.21	$9,165.75
2002	11.50	$220,930.50	34.00	27.45	0.8073	1.0000	$178,364.59	$6,497.96
2001	12.50	$393,021.03	34.00	27.02	0.7948	1.0000	$312,387.21	$11,559.44
2000	13.50	$345,462.40	34.00	26.61	0.7827	1.0000	$270,384.98	$10,160.66
1999	14.50	$539,262.52	34.00	26.21	0.7708	1.0000	$415,672.88	$15,860.66
1998	15.50	$434,675.72	34.00	25.81	0.7592	1.0000	$330,020.78	$12,784.58
1997	16.50	$179,646.29	34.00	25.43	0.7479	1.0000	$134,351.86	$5,283.71
1996	17.50	$129,373.49	34.00	25.05	0.7367	1.0000	$95,307.31	$3,805.10
1995	18.50	$139,855.97	34.00	24.67	0.7257	1.0000	$101,490.35	$4,113.41
1994	19.50	$469,090.83	34.00	24.30	0.7148	1.0000	$335,323.63	$13,796.79
1993	20.50	$372,981.15	34.00	23.94	0.7042	1.0000	$262,636.24	$10,970.03
1992	21.50	$166,001.47	34.00	23.58	0.6936	1.0000	$115,143.73	$4,882.40
1991	22.50	$200,011.42	34.00	23.23	0.6833	1.0000	$136,661.43	$5,882.69
1990	23.50	$155,504.43	34.00	22.88	0.6731	1.0000	$104,662.37	$4,573.66
1989	24.50	$124,040.49	34.00	22.54	0.6630	1.0000	$82,237.73	$3,648.25
1988	25.50	$87,179.52	34.00	22.20	0.6531	1.0000	$56,935.45	$2,564.10
1987	26.50	$161,566.86	34.00	21.87	0.6433	1.0000	$103,939.00	$4,751.97
1986	27.50	$88,038.54	34.00	21.55	0.6337	1.0000	$55,789.10	$2,589.37
1985	28.50	$41,447.68	34.00	21.22	0.6242	1.0000	$25,872.05	$1,219.05
1984	29.50	$52,844.69	34.00	20.91	0.6149	1.0000	$32,491.98	$1,554.26
1983	30.50	$35,899.36	34.00	20.59	0.6056	1.0000	$21,742.44	$1,055.86
1982	31.50	$47,739.85	34.00	20.28	0.5966	1.0000	$28,480.48	$1,404.11
1981	32.50	$36,194.16	34.00	19.98	0.5876	1.0000	$21,268.37	$1,064.53

Generation Arrangement Report

Account: MTED 101/6-373 Street Lighting
Dispersion: 34.00 - L0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$32,731.96	34.00	19.68	0.5788	1.0000	$18,945.17	$962.70
1979	34.50	$31,659.06	34.00	19.38	0.5701	1.0000	$18,048.21	$931.15
1978	35.50	$36,226.20	34.00	19.09	0.5615	1.0000	$20,341.02	$1,065.48
1977	36.50	$26,665.46	34.00	18.80	0.5530	1.0000	$14,747.11	$784.28
1976	37.50	$15,106.05	34.00	18.52	0.5447	1.0000	$8,228.29	$444.30
1975	38.50	$11,909.48	34.00	18.24	0.5365	1.0000	$6,389.12	$350.28
1974	39.50	$23,494.25	34.00	17.96	0.5284	1.0000	$12,413.29	$691.01
1973	40.50	$62,886.97	34.00	17.69	0.5204	1.0000	$32,723.43	$1,849.62
1972	41.50	$40,824.49	34.00	17.42	0.5125	1.0000	$20,921.06	$1,200.72
1971	42.50	$32,561.53	34.00	17.16	0.5047	1.0000	$16,432.69	$957.69
1970	43.50	$37,873.22	34.00	16.90	0.4970	1.0000	$18,822.29	$1,113.92
1969	44.50	$92,896.74	34.00	16.64	0.4894	1.0000	$45,464.26	$2,732.26
1968	45.50	$60,667.51	34.00	16.39	0.4819	1.0000	$29,237.32	$1,784.34
1967	46.50	$51,613.20	34.00	16.13	0.4745	1.0000	$24,492.12	$1,518.04
1966	47.50	$24,375.75	34.00	15.89	0.4672	1.0000	$11,389.53	$716.93
1965	48.50	$69,539.70	34.00	15.64	0.4601	1.0000	$31,992.45	$2,045.29
1964	49.50	$23,071.31	34.00	15.40	0.4530	1.0000	$10,450.63	$678.57
1963	50.50	$10,834.18	34.00	15.16	0.4460	1.0000	$4,831.64	$318.65
1962	51.50	$8,939.78	34.00	14.93	0.4390	1.0000	$3,924.56	$262.93
1961	52.50	$19,723.94	34.00	14.69	0.4322	1.0000	$8,523.76	$580.12
1960	53.50	$14,724.45	34.00	14.46	0.4254	1.0000	$6,263.82	$433.07
1959	54.50	$6,617.45	34.00	14.24	0.4187	1.0000	$2,770.95	$194.63
1958	55.50	$12,226.50	34.00	14.01	0.4121	1.0000	$5,039.15	$359.60
1957	56.50	$4,792.22	34.00	13.79	0.4056	1.0000	$1,943.96	$140.95
1956	57.50	$7,949.81	34.00	13.57	0.3992	1.0000	$3,173.61	$233.82
1955	58.50	$4,465.73	34.00	13.36	0.3929	1.0000	$1,754.40	$131.35
1954	59.50	$11,407.15	34.00	13.14	0.3866	1.0000	$4,409.71	$335.50
1953	60.50	$4,429.24	34.00	12.93	0.3804	1.0000	$1,684.87	$130.27
1952	61.50	$3,830.91	34.00	12.72	0.3743	1.0000	$1,433.73	$112.67
1951	62.50	$575.52	34.00	12.52	0.3682	1.0000	$211.92	$16.93
1943	70.50	$34,550.83	34.00	10.95	0.3221	1.0000	$11,128.53	$1,016.20
		$12,229,687.55	34.00	27.87	0.8197	1.0000	$10,024,323.65	$359,696.69

Remaining Life Depreciation Accrual

Account: MTED 101/6-38920 Land Rights
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 50.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$18,077.52	7.44	$399.75	2.211293%	13.447586%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$18,077.52 *		$399.75	2.211293%	13.447586%
Average:	$18,077.52		$399.75	2.211293%	13.447586%
Grand Total:	$18,077.52 *		$399.75	2.211293%	13.447586%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-38920 Land Rights
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 50 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$18,077.52	$15,104.89	0.8356	$2,972.63	0.1644
Computed	$18,077.52	$15,388.93	0.8513	$2,688.59	0.1487
Difference		($284.04)	-0.0157	$284.04	0.0157

Generation Arrangement Report

Account: MTED 101/6-38920 Land Rights
Dispersion: 50.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1996	17.50	$24.33	50.00	32.50	0.6500	1.0000	$15.81	$0.49
1990	23.50	$54.56	50.00	26.50	0.5300	1.0000	$28.92	$1.09
1972	41.50	$15,551.46	50.00	8.50	0.1700	1.0000	$2,643.75	$311.03
1969	44.50	$1.00	50.00	5.50	0.1100	1.0000	$0.11	$0.02
1963	50.50	$281.19	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	51.50	$1,489.00	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1949	64.50	$472.07	50.00	0.00	0.0000	0.0000	$0.00	$0.00
1948	65.50	$203.91	50.00	0.00	0.0000	0.0000	$0.00	$0.00
		$18,077.52	50.00	7.44	0.1487	1.0000	$2,688.59	$312.63

Remaining Life Depreciation Accrual

Account: MTED 101/6-39010 Structures
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 40.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$18,513,559.38	26.29	$410,302.35	2.216226%	3.804058%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($303,216.78)	0.50	($3,790.21)	1.250000%	
Total:	$18,513,559.38 *		$406,512.14	2.195754%	3.768917%
Average:	$18,361,950.99		$406,512.14	2.213883%	3.822649%
Grand Total:	$18,513,559.38 *		$406,512.14	2.195754%	3.768917%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39010 Structures
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 40 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$18,513,559.38	$7,727,646.60	0.4174	$10,785,912.78	0.5826
Computed	$18,513,559.38	$6,346,578.37	0.3428	$12,166,981.01	0.6572
Difference		$1,381,068.23	0.0746	($1,381,068.23)	-0.0746

Generation Arrangement Report

Account: MTED 101/6-39010 Structures
Dispersion: 40.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$1,029,595.11	40.00	39.59	0.9897	1.0000	$1,018,991.36	$25,739.88
2012	1.50	$977,175.98	40.00	38.77	0.9692	1.0000	$947,090.85	$24,429.40
2011	2.50	$1,849,998.86	40.00	37.95	0.9489	1.0000	$1,755,404.69	$46,249.97
2010	3.50	$56,936.02	40.00	37.15	0.9287	1.0000	$52,874.20	$1,423.40
2009	4.50	$434,952.82	40.00	36.34	0.9086	1.0000	$395,206.76	$10,873.82
2008	5.50	$377,021.39	40.00	35.55	0.8887	1.0000	$335,055.95	$9,425.53
2007	6.50	$148,515.12	40.00	34.76	0.8689	1.0000	$129,051.36	$3,712.88
2006	7.50	$16,124.84	40.00	33.97	0.8493	1.0000	$13,695.03	$403.12
2005	8.50	$251,572.68	40.00	33.19	0.8299	1.0000	$208,769.18	$6,289.32
2004	9.50	$77,708.17	40.00	32.42	0.8105	1.0000	$62,984.17	$1,942.70
2003	10.50	$179,581.59	40.00	31.65	0.7914	1.0000	$142,114.23	$4,489.54
2002	11.50	$111,448.05	40.00	30.89	0.7723	1.0000	$86,074.76	$2,786.20
2001	12.50	$82,147.81	40.00	30.14	0.7535	1.0000	$61,895.44	$2,053.70
2000	13.50	$69,182.75	40.00	29.39	0.7347	1.0000	$50,831.21	$1,729.57
1998	15.50	$295,351.63	40.00	27.91	0.6978	1.0000	$206,095.19	$7,383.79
1997	16.50	$197,372.16	40.00	27.18	0.6796	1.0000	$134,131.90	$4,934.30
1996	17.50	$1,721,158.42	40.00	26.46	0.6615	1.0000	$1,138,624.51	$43,028.96
1995	18.50	$2,116,988.67	40.00	25.75	0.6437	1.0000	$1,362,734.26	$52,924.72
1994	19.50	$527,055.20	40.00	25.04	0.6261	1.0000	$329,968.08	$13,176.38
1993	20.50	$154,309.09	40.00	24.35	0.6086	1.0000	$93,918.29	$3,857.73
1992	21.50	$307,431.80	40.00	23.66	0.5914	1.0000	$181,816.81	$7,685.79
1991	22.50	$102,292.60	40.00	22.98	0.5744	1.0000	$58,759.88	$2,557.32
1990	23.50	$3,247,911.05	40.00	22.31	0.5577	1.0000	$1,811,223.73	$81,197.78
1989	24.50	$235,690.66	40.00	21.65	0.5412	1.0000	$127,545.39	$5,892.27
1988	25.50	$1,233,711.23	40.00	20.99	0.5249	1.0000	$647,542.77	$30,842.78
1987	26.50	$195,682.81	40.00	20.36	0.5089	1.0000	$99,579.90	$4,892.07
1986	27.50	$131,842.77	40.00	19.73	0.4931	1.0000	$65,015.55	$3,296.07
1985	28.50	$49,477.59	40.00	19.11	0.4777	1.0000	$23,634.46	$1,236.94
1984	29.50	$69,819.73	40.00	18.50	0.4625	1.0000	$32,289.94	$1,745.49
1983	30.50	$120,681.33	40.00	17.90	0.4476	1.0000	$54,016.94	$3,017.03
1982	31.50	$13,977.23	40.00	17.32	0.4330	1.0000	$6,051.91	$349.43
1981	32.50	$2,271.33	40.00	16.75	0.4187	1.0000	$951.00	$56.78
1980	33.50	$93,002.93	40.00	16.19	0.4047	1.0000	$37,637.01	$2,325.07

Generation Arrangement Report

Account: MTED 101/6-39010 Structures
Dispersion: 40.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1979	34.50	$65,331.40	40.00	15.64	0.3910	1.0000	$25,546.27	$1,633.29
1978	35.50	$84,031.98	40.00	15.11	0.3776	1.0000	$31,734.55	$2,100.80
1977	36.50	$22,534.21	40.00	14.58	0.3646	1.0000	$8,216.34	$563.36
1976	37.50	$4,620.93	40.00	14.08	0.3519	1.0000	$1,626.03	$115.52
1975	38.50	$1,745.00	40.00	13.58	0.3395	1.0000	$592.44	$43.63
1974	39.50	$3,994.36	40.00	13.10	0.3274	1.0000	$1,307.89	$99.86
1973	40.50	$12,600.41	40.00	12.63	0.3157	1.0000	$3,978.08	$315.01
1972	41.50	$263,219.15	40.00	12.17	0.3043	1.0000	$80,097.41	$6,580.48
1971	42.50	$888.72	40.00	11.73	0.2932	1.0000	$260.60	$22.22
1970	43.50	$2,379.58	40.00	11.30	0.2825	1.0000	$672.15	$59.49
1969	44.50	$449,637.94	40.00	10.88	0.2720	1.0000	$122,314.35	$11,240.95
1968	45.50	$407,752.30	40.00	10.48	0.2619	1.0000	$106,792.19	$10,193.81
1967	46.50	$341,543.77	40.00	10.08	0.2521	1.0000	$86,095.73	$8,538.59
1966	47.50	$2,737.97	40.00	9.70	0.2426	1.0000	$664.11	$68.45
1965	48.50	$343.73	40.00	9.33	0.2333	1.0000	$80.19	$8.59
1964	49.50	$1,350.10	40.00	8.97	0.2243	1.0000	$302.86	$33.75
1963	50.50	$12,418.26	40.00	8.62	0.2156	1.0000	$2,677.17	$310.46
1962	51.50	$3,385.41	40.00	8.28	0.2071	1.0000	$701.14	$84.64
1961	52.50	$246.48	40.00	7.95	0.1988	1.0000	$49.00	$6.16
1960	53.50	$510.65	40.00	7.63	0.1908	1.0000	$97.42	$12.77
1959	54.50	$687.48	40.00	7.31	0.1829	1.0000	$125.71	$17.19
1958	55.50	$170.00	40.00	7.01	0.1752	1.0000	$29.78	$4.25
1957	56.50	$1,934.89	40.00	6.70	0.1676	1.0000	$324.25	$48.37
1956	57.50	$37,478.30	40.00	6.41	0.1602	1.0000	$6,003.99	$936.96
1955	58.50	$76,603.00	40.00	6.12	0.1529	1.0000	$11,711.14	$1,915.08
1954	59.50	$175.00	40.00	5.83	0.1458	1.0000	$25.51	$4.38
1949	64.50	$19.76	40.00	4.49	0.1122	1.0000	$2.22	$0.49
1948	65.50	$388.31	40.00	4.24	0.1061	1.0000	$41.19	$9.71
1947	66.50	$6,594.83	40.00	4.00	0.1000	1.0000	$659.64	$164.87
1946	67.50	$2,419.92	40.00	3.77	0.0943	1.0000	$228.31	$60.50
1944	69.50	$6,809.62	40.00	3.33	0.0832	1.0000	$566.57	$170.24
1943	70.50	$100.16	40.00	3.10	0.0775	1.0000	$7.76	$2.50
1938	75.50	$44,312.15	40.00	1.69	0.0422	1.0000	$1,868.00	$1,107.80

Generation Arrangement Report

Account: MTED 101/6-39010 Structures
Dispersion: 40.00 - R1.5

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1936	77.50	$163.90	40.00	1.05	0.0262	1.0000	$4.29	$4.10
1928	85.50	$96,200.28	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	87.50	$206.46	40.00	0.00	0.0000	0.0000	$0.00	$0.00
1923	90.50	$80,033.55	40.00	0.00	0.0000	0.0000	$0.00	$0.00
		$18,513,559.38	40.00	26.29	0.6572	1.0000	$12,166,981.01	$458,427.98

Remaining Life Depreciation Accrual

Account: MTED 101/6-39010 South Bldg Reading
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$50,456,452.54	22.63	$1,121,753.83	2.223212%	4.418496%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($261,183.43)	0.50	($3,002.02)	1.149391%	
Total:	$50,456,452.54 *		$1,118,751.81	2.217262%	4.406671%
Average:	$50,325,860.83		$1,118,751.81	2.223016%	4.429456%
Grand Total:	$50,456,452.54 *		$1,118,751.81	2.217262%	4.406671%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39010 South Bldg Reading
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$50,456,452.54	$25,068,766.07	0.4968	$25,387,686.47	0.5032
Computed	$50,456,452.54	$21,779,236.75	0.4316	$28,677,215.79	0.5684
Difference		$3,289,529.32	0.0652	($3,289,529.32)	-0.0652

Generation Arrangement Report

Account: MTED 101/6-39010 South Bldg Reading
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$1,500,662.83	24.29	23.75	0.9778	1.0000	$1,467,418.93	$61,786.25
2012	1.50	$66,331.61	25.21	23.68	0.9395	1.0000	$62,315.26	$2,631.46
2011	2.50	$603,148.94	26.12	23.62	0.9041	1.0000	$545,287.86	$23,090.66
2010	3.50	$475,095.96	27.03	23.55	0.8713	1.0000	$413,974.70	$17,577.22
2009	4.50	$793,214.52	27.93	23.49	0.8409	1.0000	$667,053.13	$28,398.53
2008	5.50	$550,507.35	28.83	23.43	0.8128	1.0000	$447,426.98	$19,096.16
2007	6.50	$1,020,438.72	29.72	23.37	0.7865	1.0000	$802,536.13	$34,336.38
2006	7.50	$871,795.98	30.60	23.32	0.7619	1.0000	$664,213.99	$28,486.78
2005	8.50	$795,241.17	31.48	23.26	0.7388	1.0000	$587,556.63	$25,260.18
2004	9.50	$2,151,720.43	32.35	23.21	0.7173	1.0000	$1,543,351.39	$66,505.10
2003	10.50	$181,063.55	33.22	23.15	0.6970	1.0000	$126,197.97	$5,450.43
2002	11.50	$27,328.98	34.08	23.10	0.6779	1.0000	$18,525.62	$801.92
2001	12.50	$607,627.25	34.93	23.05	0.6598	1.0000	$400,925.42	$17,394.51
2000	13.50	$549,096.37	35.78	23.00	0.6428	1.0000	$352,963.15	$15,347.23
1999	14.50	$173,979.93	36.62	22.95	0.6267	1.0000	$109,035.04	$4,751.28
1998	15.50	$2,285,684.57	37.45	22.90	0.6115	1.0000	$1,397,593.18	$61,033.11
1997	16.50	$630,488.37	38.28	22.85	0.5970	1.0000	$376,373.30	$16,472.43
1996	17.50	$2,014,003.97	39.09	22.80	0.5832	1.0000	$1,174,619.89	$51,517.26
1995	18.50	$614,197.37	39.91	22.75	0.5702	1.0000	$350,189.61	$15,391.47
1994	19.50	$797,293.70	40.71	22.70	0.5577	1.0000	$444,667.37	$19,585.14
1993	20.50	$4,660,046.57	41.51	22.66	0.5458	1.0000	$2,543,660.25	$112,274.42
1992	21.50	$311,889.99	42.30	22.61	0.5345	1.0000	$166,717.00	$7,374.11
1991	22.50	$13,196,544.72	43.08	22.56	0.5237	1.0000	$6,911,611.43	$306,346.48
1990	23.50	$2,888,260.57	43.85	22.51	0.5134	1.0000	$1,482,904.63	$65,864.42
1989	24.50	$1,347,234.88	44.62	22.47	0.5035	1.0000	$678,376.06	$30,194.58
1988	25.50	$518,320.32	45.38	22.42	0.4941	1.0000	$256,091.02	$11,422.38
1987	26.50	$5,451,561.90	46.13	22.37	0.4850	1.0000	$2,644,126.31	$118,180.71
1986	27.50	$138,282.78	46.87	22.33	0.4763	1.0000	$65,868.61	$2,950.18
1985	28.50	$243,779.90	47.61	22.28	0.4680	1.0000	$114,083.11	$5,120.51
1984	29.50	$172,507.72	48.34	22.23	0.4600	1.0000	$79,349.35	$3,568.90
1983	30.50	$100,670.63	49.06	22.19	0.4523	1.0000	$45,530.75	$2,052.14
1982	31.50	$132,778.97	49.77	22.14	0.4449	1.0000	$59,069.66	$2,667.95
1981	32.50	$10,468.66	50.47	22.09	0.4377	1.0000	$4,582.42	$207.42

Generation Arrangement Report

Account: MTED 101/6-39010 South Bldg Reading
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1980	33.50	$101,564.45	51.17	22.05	0.4309	1.0000	$43,760.56	$1,984.93
1979	34.50	$105,880.92	51.86	22.00	0.4243	1.0000	$44,920.12	$2,041.85
1978	35.50	$850,594.01	52.53	21.95	0.4179	1.0000	$355,437.47	$16,191.11
1977	36.50	$34,965.49	53.21	21.90	0.4117	1.0000	$14,395.32	$657.18
1976	37.50	$6,716.02	53.87	21.86	0.4058	1.0000	$2,725.09	$124.67
1975	38.50	$34,312.44	54.52	21.81	0.4000	1.0000	$13,725.58	$629.32
1974	39.50	$32,027.93	55.17	21.76	0.3945	1.0000	$12,633.99	$580.54
1973	40.50	$270,359.79	55.81	21.71	0.3891	1.0000	$105,193.62	$4,844.59
1972	41.50	$99,520.61	56.44	21.67	0.3839	1.0000	$38,205.80	$1,763.43
1971	42.50	$41,920.92	57.06	21.62	0.3789	1.0000	$15,882.62	$734.73
1970	43.50	$23,882.00	57.67	21.57	0.3740	1.0000	$8,931.88	$414.12
1969	44.50	$32,772.04	58.27	21.52	0.3693	1.0000	$12,101.78	$562.39
1968	45.50	$27,319.64	58.87	21.47	0.3647	1.0000	$9,963.39	$464.09
1967	46.50	$1,213,321.82	59.45	21.42	0.3603	1.0000	$437,111.09	$20,407.71
1966	47.50	$577,054.93	60.03	21.37	0.3560	1.0000	$205,402.84	$9,612.45
1965	48.50	$5,502.57	60.60	21.32	0.3518	1.0000	$1,935.60	$90.80
1964	49.50	$16,135.71	61.16	21.27	0.3477	1.0000	$5,610.38	$263.82
1963	50.50	$17,906.07	61.71	21.21	0.3438	1.0000	$6,155.27	$290.15
1962	51.50	$1,118.40	62.26	21.16	0.3399	1.0000	$380.16	$17.96
1961	52.50	$5,397.23	62.79	21.11	0.3362	1.0000	$1,814.39	$85.95
1960	53.50	$1,949.52	63.32	21.06	0.3325	1.0000	$648.29	$30.79
1957	56.50	$2,900.26	64.84	20.89	0.3222	1.0000	$934.43	$44.73
1956	57.50	$2,259.88	65.34	20.84	0.3189	1.0000	$720.72	$34.59
1955	58.50	$2,084.98	65.82	20.78	0.3157	1.0000	$658.27	$31.68
1954	59.50	$1,067,661.95	66.29	20.72	0.3126	1.0000	$333,754.40	$16,105.36
1953	60.50	$51.61	66.76	20.67	0.3096	1.0000	$15.98	$0.77
1943	70.50	$2.17	70.94	20.04	0.2825	1.0000	$0.61	$0.03
		$50,456,452.54	40.01	22.63	0.5684	1.0000	$28,677,215.79	$1,261,147.45

Remaining Life Depreciation Accrual

Account: MTED 101/6-39010 Lebanon Serv Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$5,087,649.98	9.22	$218,576.89	4.296225%	10.843273%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($29,333.59)	0.50	($419.23)	1.429181%	
Total:	$5,087,649.98 *		$218,157.66	4.287985%	10.822475%
Average:	$5,072,983.19		$218,157.66	4.300382%	10.901796%
Grand Total:	$5,087,649.98 *		$218,157.66	4.287985%	10.822475%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39010 Lebanon Serv Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$5,087,649.98	$3,071,866.61	0.6038	$2,015,783.37	0.3962
Computed	$5,087,649.98	$3,049,418.51	0.5994	$2,038,231.47	0.4006
Difference		$22,448.10	0.0044	($22,448.10)	-0.0044

Generation Arrangement Report

Account: MTED 101/6-39010 Lebanon Serv Ctr
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	($216.63)	9.95	9.44	0.9490	1.0000	($205.58)	($21.78)
2012	1.50	$762,751.61	10.93	9.43	0.8625	1.0000	$657,856.65	$69,797.73
2011	2.50	$29,328.85	11.91	9.41	0.7905	1.0000	$23,184.96	$2,462.98
2010	3.50	$68,115.11	12.88	9.40	0.7297	1.0000	$49,705.75	$5,286.60
2009	4.50	$9,769.54	13.86	9.39	0.6777	1.0000	$6,620.48	$704.99
2008	5.50	$283,322.32	14.83	9.38	0.6327	1.0000	$179,249.92	$19,108.17
2007	6.50	$38,888.21	15.79	9.37	0.5934	1.0000	$23,074.72	$2,462.36
2006	7.50	$16,871.12	16.75	9.36	0.5587	1.0000	$9,426.41	$1,006.93
2005	8.50	$490,120.02	17.71	9.35	0.5280	1.0000	$258,766.00	$27,670.61
2004	9.50	$61,987.63	18.67	9.34	0.5005	1.0000	$31,025.84	$3,320.87
2002	11.50	$7,536.60	20.56	9.33	0.4536	1.0000	$3,418.42	$366.58
2001	12.50	$189,800.79	21.50	9.32	0.4333	1.0000	$82,247.08	$8,828.33
2000	13.50	$7,552.50	22.43	9.31	0.4149	1.0000	$3,133.60	$336.66
1999	14.50	$16,870.67	23.36	9.30	0.3980	1.0000	$6,715.35	$722.10
1998	15.50	$5,338.09	24.29	9.29	0.3826	1.0000	$2,042.15	$219.78
1997	16.50	$16,786.42	25.21	9.28	0.3683	1.0000	$6,182.02	$665.94
1996	17.50	$9,986.11	26.12	9.28	0.3551	1.0000	$3,546.02	$382.30
1993	20.50	$164,151.89	28.83	9.25	0.3209	1.0000	$52,680.47	$5,694.15
1992	21.50	$347,810.18	29.72	9.24	0.3110	1.0000	$108,185.96	$11,703.34
1991	22.50	$115,501.93	30.60	9.24	0.3018	1.0000	$34,859.66	$3,774.14
1990	23.50	$3,984.48	31.48	9.23	0.2931	1.0000	$1,168.05	$126.56
1989	24.50	$229,307.03	32.35	9.22	0.2850	1.0000	$65,353.04	$7,087.39
1988	25.50	$49,281.68	33.22	9.21	0.2773	1.0000	$13,668.14	$1,483.49
1987	26.50	$108,719.31	34.08	9.21	0.2701	1.0000	$29,368.87	$3,190.18
1986	27.50	$29,374.80	34.93	9.20	0.2633	1.0000	$7,735.16	$840.91
1985	28.50	$38,293.80	35.78	9.19	0.2569	1.0000	$9,836.94	$1,070.31
1984	29.50	$187,028.19	36.62	9.18	0.2508	1.0000	$46,905.54	$5,107.62
1983	30.50	$14,849.24	37.45	9.18	0.2450	1.0000	$3,638.35	$396.51
1982	31.50	$13,933.41	38.28	9.17	0.2395	1.0000	$3,337.64	$364.03
1981	32.50	$2,563.54	39.09	9.16	0.2343	1.0000	$600.71	$65.57
1979	34.50	$9,949.28	40.71	9.15	0.2247	1.0000	$2,235.25	$244.40
1978	35.50	$1,272.00	41.51	9.14	0.2202	1.0000	$280.06	$30.65
1977	36.50	$5,997.30	42.30	9.13	0.2159	1.0000	$1,294.68	$141.80

Generation Arrangement Report

Account: MTED 101/6-39010 Lebanon Serv Ctr
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1976	37.50	$1,970.88	43.08	9.12	0.2118	1.0000	$417.40	$45.75
1975	38.50	$2,929.78	43.85	9.12	0.2079	1.0000	$609.02	$66.81
1974	39.50	$29,931.53	44.62	9.11	0.2041	1.0000	$6,109.90	$670.83
1973	40.50	$22,095.79	45.38	9.10	0.2005	1.0000	$4,431.07	$486.93
1972	41.50	$623.97	46.13	9.09	0.1971	1.0000	$122.99	$13.53
1971	42.50	$1,823.72	46.87	9.08	0.1938	1.0000	$353.47	$38.91
1970	43.50	$2,960.38	47.61	9.08	0.1907	1.0000	$564.42	$62.18
1969	44.50	$9,343.58	48.34	9.07	0.1876	1.0000	$1,753.03	$193.30
1968	45.50	$17,184.22	49.06	9.06	0.1847	1.0000	$3,174.00	$350.30
1967	46.50	$6,586.71	49.77	9.05	0.1819	1.0000	$1,198.14	$132.35
1966	47.50	$2,016.11	50.47	9.04	0.1792	1.0000	$361.30	$39.95
1965	48.50	$1,653,356.29	51.17	9.04	0.1766	1.0000	$291,998.42	$32,312.47
		$5,087,649.98	23.23	9.22	0.4006	1.0000	$2,038,231.47	$219,055.48

Remaining Life Depreciation Accrual

Account: MTED 101/6-39010 Easton Serv Center
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$4,604,359.68	4.44	$151,511.58	3.290611%	22.545327%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($29,047.67)	0.50	($480.80)	1.655210%	
Total:	$4,604,359.68 *		$151,030.78	3.280169%	22.473782%
Average:	$4,589,835.85		$151,030.78	3.290549%	22.970211%
Grand Total:	$4,604,359.68 *		$151,030.78	3.280169%	22.473782%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39010 Easton Serv Center
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$4,604,359.68	$3,932,328.69	0.8540	$672,030.99	0.1460
Computed	$4,604,359.68	$3,684,385.29	0.8002	$919,974.39	0.1998
Difference		$247,943.40	0.0538	($247,943.40)	-0.0538

Generation Arrangement Report

Account: MTED 101/6-39010 Easton Serv Center
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2012	1.50	$58,679.98	5.99	4.49	0.7495	1.0000	$43,982.08	$9,800.42
2011	2.50	$244,425.93	6.98	4.48	0.6425	1.0000	$157,045.15	$35,016.13
2010	3.50	$24,747.33	7.97	4.48	0.5623	1.0000	$13,915.75	$3,104.63
2008	5.50	$15,370.01	9.95	4.48	0.4502	1.0000	$6,919.27	$1,545.48
2007	6.50	$65,349.08	10.93	4.47	0.4095	1.0000	$26,759.21	$5,979.95
2005	8.50	$116,963.58	12.88	4.47	0.3469	1.0000	$40,579.94	$9,077.86
2004	9.50	$15,289.62	13.86	4.47	0.3224	1.0000	$4,929.86	$1,103.33
2003	10.50	$88,710.82	14.83	4.47	0.3012	1.0000	$26,720.83	$5,982.94
2002	11.50	$45,902.84	15.79	4.46	0.2827	1.0000	$12,975.16	$2,906.51
2001	12.50	$66,481.90	16.75	4.46	0.2663	1.0000	$17,704.80	$3,967.90
2000	13.50	$242,343.72	17.71	4.46	0.2518	1.0000	$61,023.23	$13,681.95
1999	14.50	$17,372.32	18.67	4.46	0.2388	1.0000	$4,149.27	$930.69
1998	15.50	$63,557.88	19.62	4.46	0.2272	1.0000	$14,439.91	$3,240.26
1997	16.50	$465.59	20.56	4.45	0.2167	1.0000	$100.87	$22.65
1996	17.50	$106,358.92	21.50	4.45	0.2071	1.0000	$22,027.88	$4,947.14
1995	18.50	$18,941.46	22.43	4.45	0.1984	1.0000	$3,757.97	$844.33
1994	19.50	$315,893.59	23.36	4.45	0.1904	1.0000	$60,155.40	$13,520.83
1993	20.50	$10,060.09	24.29	4.45	0.1831	1.0000	$1,842.02	$414.20
1992	21.50	$326,871.94	25.21	4.45	0.1764	1.0000	$57,645.88	$12,967.43
1991	22.50	$79,320.97	26.12	4.44	0.1701	1.0000	$13,494.25	$3,036.69
1990	23.50	$49,781.71	27.03	4.44	0.1643	1.0000	$8,181.28	$1,841.78
1989	24.50	$762,550.19	27.93	4.44	0.1590	1.0000	$121,220.22	$27,300.69
1988	25.50	$128,878.50	28.83	4.44	0.1540	1.0000	$19,842.54	$4,470.57
1987	26.50	$228,795.84	29.72	4.44	0.1493	1.0000	$34,157.44	$7,698.67
1986	27.50	$33,373.66	30.60	4.44	0.1449	1.0000	$4,836.54	$1,090.52
1985	28.50	$25,680.47	31.48	4.43	0.1408	1.0000	$3,616.28	$815.72
1984	29.50	$67,557.25	32.35	4.43	0.1370	1.0000	$9,253.50	$2,088.05
1983	30.50	$45,187.07	33.22	4.43	0.1334	1.0000	$6,025.76	$1,360.24
1982	31.50	$8,182.31	34.08	4.43	0.1299	1.0000	$1,063.21	$240.10
1981	32.50	$7,060.29	34.93	4.43	0.1267	1.0000	$894.65	$202.11
1979	34.50	$5,272.82	36.62	4.42	0.1208	1.0000	$636.92	$144.00
1978	35.50	$673.65	37.45	4.42	0.1181	1.0000	$79.53	$17.99
1977	36.50	$689.03	38.28	4.42	0.1155	1.0000	$79.56	$18.00

Generation Arrangement Report

Account: MTED 101/6-39010 Easton Serv Center
Dispersion: 80.00 - S0

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1976	37.50	$9,710.27	39.09	4.42	0.1130	1.0000	$1,097.34	$248.38
1974	39.50	$28,072.24	40.71	4.41	0.1084	1.0000	$3,044.16	$689.58
1973	40.50	$4,879.76	41.51	4.41	0.1063	1.0000	$518.79	$117.57
1972	41.50	$11,216.29	42.30	4.41	0.1043	1.0000	$1,169.74	$265.19
1971	42.50	$4,846.49	43.08	4.41	0.1024	1.0000	$496.07	$112.51
1970	43.50	$71,304.58	43.85	4.41	0.1005	1.0000	$7,166.72	$1,626.04
1969	44.50	$2,350.70	44.62	4.41	0.0987	1.0000	$232.11	$52.68
1968	45.50	$434.20	45.38	4.40	0.0970	1.0000	$42.14	$9.57
1967	46.50	$690.18	46.13	4.40	0.0954	1.0000	$65.86	$14.96
1966	47.50	$2,298.62	46.87	4.40	0.0939	1.0000	$215.78	$49.04
1965	48.50	$1,126.00	47.61	4.40	0.0924	1.0000	$104.03	$23.65
1964	49.50	$158.34	48.34	4.40	0.0910	1.0000	$14.40	$3.28
1963	50.50	$1,180,035.91	49.06	4.39	0.0896	1.0000	$105,711.75	$24,054.73
1962	51.50	$445.74	49.77	4.39	0.0883	1.0000	$39.34	$8.96
		$4,604,359.68	22.28	4.44	0.1998	1.0000	$919,974.39	$206,655.87

Remaining Life Depreciation Accrual

Account: MTED 101/6-39010 York Serv Center
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - S0
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2013

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2013 Additions	$7,014,293.10	15.70	$196,425.33	2.800358%	6.370602%
2013 Additions	$0.00	0.00	$0.00	0.000000%	
2013 Retirements	($36,442.05)	0.50	($504.41)	1.384143%	
Total:	$7,014,293.10 *		$195,920.92	2.793167%	6.354243%
Average:	$6,996,072.07		$195,920.92	2.800442%	6.392017%
Grand Total:	$7,014,293.10 *		$195,920.92	2.793167%	6.354243%

* Excluding 2013 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39010 York Serv Center
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - S0
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2013

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$7,014,293.10	$3,930,984.39	0.5604	$3,083,308.71	0.4396
Computed	$7,014,293.10	$3,666,384.00	0.5227	$3,347,909.10	0.4773
Difference		$264,600.39	0.0377	($264,600.39)	-0.0377

Generation Arrangement Report

Account: MTED 101/6-39010 York Serv Center
Dispersion: 80.00 - S0

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2013

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.00	$2,339.09	15.79	15.78	0.9989	1.0000	$2,336.47	$148.11
2011	1.50	$193,390.36	17.71	16.20	0.9147	1.0000	$176,888.16	$10,918.20
2008	4.50	$55,781.09	20.56	16.11	0.7834	1.0000	$43,699.84	$2,713.16
2007	5.50	$32,515.63	21.50	16.08	0.7479	1.0000	$24,316.86	$1,512.42
2005	7.50	$70,277.83	23.36	16.02	0.6858	1.0000	$48,198.06	$3,008.02
2004	8.50	$134,879.46	24.29	16.00	0.6586	1.0000	$88,829.94	$5,553.34
2003	9.50	$20,574.70	25.21	15.97	0.6336	1.0000	$13,035.13	$816.22
2002	10.50	$213,616.46	26.12	15.94	0.6104	1.0000	$130,396.43	$8,177.99
2001	11.50	$98,077.08	27.03	15.92	0.5890	1.0000	$57,766.31	$3,628.58
2000	12.50	$23,440.74	27.93	15.89	0.5691	1.0000	$13,338.99	$839.22
1998	14.50	$79,156.93	29.72	15.85	0.5332	1.0000	$42,208.17	$2,663.52
1997	15.50	$4,454.10	30.60	15.82	0.5170	1.0000	$2,302.93	$145.54
1996	16.50	$50,571.95	31.48	15.80	0.5018	1.0000	$25,379.19	$1,606.38
1995	17.50	$760,405.22	32.35	15.78	0.4876	1.0000	$370,782.56	$23,502.51
1994	18.50	$3,521,484.99	33.22	15.75	0.4742	1.0000	$1,669,935.72	$106,004.83
1993	19.50	$14,674.50	34.08	15.73	0.4616	1.0000	$6,773.63	$430.60
1992	20.50	$60,441.23	34.93	15.71	0.4497	1.0000	$27,178.01	$1,730.25
1991	21.50	$325,458.05	35.78	15.69	0.4384	1.0000	$142,681.48	$9,096.55
1990	22.50	$9,966.86	36.62	15.66	0.4277	1.0000	$4,263.31	$272.19
1989	23.50	$108,115.95	37.45	15.64	0.4177	1.0000	$45,154.67	$2,886.95
1988	24.50	$57,368.67	38.28	15.62	0.4081	1.0000	$23,409.36	$1,498.84
1987	25.50	$471,523.88	39.09	15.60	0.3989	1.0000	$188,112.51	$12,061.35
1986	26.50	$86,083.67	39.91	15.57	0.3903	1.0000	$33,597.33	$2,157.21
1985	27.50	$11,473.05	40.71	15.55	0.3820	1.0000	$4,383.16	$281.83
1984	28.50	$55,638.29	41.51	15.53	0.3742	1.0000	$20,817.85	$1,340.49
1983	29.50	$1,409.79	42.30	15.51	0.3667	1.0000	$516.93	$33.33
1981	31.50	$4,535.71	43.85	15.46	0.3527	1.0000	$1,599.57	$103.43
1980	32.50	$4,404.32	44.62	15.44	0.3461	1.0000	$1,524.31	$98.71
1979	33.50	$1,237.44	45.38	15.42	0.3398	1.0000	$420.51	$27.27
1978	34.50	$4,709.73	46.13	15.40	0.3338	1.0000	$1,572.17	$102.10
1977	35.50	$3,383.43	46.87	15.38	0.3280	1.0000	$1,109.92	$72.18
1976	36.50	$413.40	47.61	15.35	0.3225	1.0000	$133.32	$8.68
1974	38.50	$1,461.62	49.06	15.31	0.3121	1.0000	$456.14	$29.79

Generation Arrangement Report

Account: MTED 101/6-39010 York Serv Center
Dispersion: 80.00 - S0
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2013

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1973	39.50	$93,768.46	49.77	15.29	0.3072	1.0000	$28,802.42	$1,884.10
1972	40.50	$8,124.72	50.47	15.26	0.3024	1.0000	$2,457.13	$160.97
1971	41.50	$1,202.29	51.17	15.24	0.2979	1.0000	$358.13	$23.50
1970	42.50	$872.92	51.86	15.22	0.2935	1.0000	$256.19	$16.83
1969	43.50	$11,353.36	52.53	15.20	0.2893	1.0000	$3,284.02	$216.11
1968	44.50	$22,686.60	53.21	15.17	0.2852	1.0000	$6,469.44	$426.39
1967	45.50	$2,135.80	53.87	15.15	0.2812	1.0000	$600.64	$39.65
1966	46.50	$8,543.41	54.52	15.13	0.2774	1.0000	$2,370.13	$156.69
1965	47.50	$3,064.50	55.17	15.10	0.2737	1.0000	$838.89	$55.55
1964	48.50	$5,174.32	55.81	15.08	0.2702	1.0000	$1,398.03	$92.72
1963	49.50	$74,905.60	56.44	15.05	0.2667	1.0000	$19,980.84	$1,327.27
1962	50.50	$648.25	57.06	15.03	0.2634	1.0000	$170.76	$11.36
1961	51.50	$1,469.62	57.67	15.01	0.2602	1.0000	$382.39	$25.48
1960	52.50	$1,745.87	58.27	14.98	0.2571	1.0000	$448.82	$29.96
1959	53.50	$2,679.76	58.87	14.96	0.2541	1.0000	$680.80	$45.52
1957	55.50	$1,055.44	60.03	14.90	0.2483	1.0000	$262.04	$17.58
1956	56.50	$2,617.82	60.60	14.88	0.2455	1.0000	$642.71	$43.20
1955	57.50	$1,117.10	61.16	14.85	0.2428	1.0000	$271.28	$18.26
1954	58.50	$4,127.44	61.71	14.83	0.2402	1.0000	$991.56	$66.88
1953	59.50	$224,197.91	62.26	14.80	0.2377	1.0000	$53,293.56	$3,601.13
1951	61.50	$7,409.36	63.32	14.74	0.2329	1.0000	$1,725.33	$117.02
1949	63.50	$551.40	64.34	14.69	0.2283	1.0000	$125.87	$8.57
1947	65.50	$180.14	65.34	14.63	0.2239	1.0000	$40.34	$2.76
1945	67.50	$425.55	66.29	14.57	0.2198	1.0000	$93.53	$6.42
1944	68.50	$655.00	66.76	14.54	0.2178	1.0000	$142.66	$9.81
1943	69.50	$412.69	67.21	14.51	0.2159	1.0000	$89.09	$6.14
1941	71.50	$34.09	68.10	14.45	0.2121	1.0000	$7.23	$0.50
1939	73.50	$298.62	68.95	14.38	0.2085	1.0000	$62.27	$4.33
1937	75.50	$350.40	69.77	14.31	0.2051	1.0000	$71.87	$5.02
1936	76.50	$146.25	70.17	14.28	0.2035	1.0000	$29.76	$2.08
1930	82.50	$407.42	72.37	14.05	0.1942	1.0000	$79.11	$5.63
1929	83.50	$14.70	72.71	14.01	0.1927	1.0000	$2.83	$0.20
1928	84.50	$258.31	73.03	13.97	0.1913	1.0000	$49.41	$3.54

Generation Arrangement Report

Account: MTED 101/6-39010 York Serv Center
Dispersion: 80.00 - S0

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2013

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1927	85.50	$2,176.86	73.36	13.93	0.1899	1.0000	$413.33	$29.68
1926	86.50	$106.10	73.67	13.89	0.1885	1.0000	$20.00	$1.44
1925	87.50	$3,428.79	73.97	13.84	0.1871	1.0000	$641.60	$46.35
1923	89.50	$60.00	74.56	13.75	0.1844	1.0000	$11.07	$0.80
1922	90.50	$4,167.27	74.84	13.70	0.1831	1.0000	$763.08	$55.69
1921	91.50	$12,070.93	75.11	13.66	0.1818	1.0000	$2,194.58	$160.71
1919	93.50	$1,464.44	75.63	13.56	0.1792	1.0000	$262.48	$19.36
1917	95.50	$468.91	76.12	13.45	0.1767	1.0000	$82.85	$6.16
1908	104.50	$440.97	77.95	12.90	0.1654	1.0000	$72.96	$5.66
1904	108.50	$24,008.49	78.58	12.60	0.1603	1.0000	$3,849.13	$305.53
		$7,014,293.10	33.00	15.70	0.4773	1.0000	$3,347,909.10	$212,532.39

Remaining Life Depreciation Accrual

Account: MTED 101/6-39020 Land/Yard Improvem
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25.00 - R1
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$4,340,628.36	9.61	$160,947.16	3.707923%	10.408190%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($398,707.81)	0.50	($7,974.16)	2.000001%	
Total:	$4,340,628.36 *		$152,973.00	3.524213%	9.892515%
Average:	$4,141,274.46		$152,973.00	3.693863%	11.356595%
Grand Total:	$4,340,628.36 *		$152,973.00	3.524213%	9.892515%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39020 Land/Yard Improvem
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25 - R1
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$4,340,628.36	$2,794,277.38	0.6437	$1,546,350.98	0.3563
Computed	$4,340,628.36	$2,672,469.75	0.6157	$1,668,158.61	0.3843
Difference		$121,807.63	0.0281	($121,807.63)	-0.0281

Generation Arrangement Report

Account: MTED 101/6-39020 Land/Yard Improvem
Dispersion: 25.00 - R1
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2012	1.50	$14,667.85	25.00	23.89	0.9558	1.0000	$14,019.50	$586.71
2011	2.50	$47,855.63	25.00	23.17	0.9268	1.0000	$44,351.95	$1,914.23
2010	3.50	$25,215.29	25.00	22.45	0.8981	1.0000	$22,645.99	$1,008.61
2009	4.50	$47,611.60	25.00	21.74	0.8697	1.0000	$41,410.13	$1,904.46
2008	5.50	$62,388.86	25.00	21.04	0.8417	1.0000	$52,511.67	$2,495.55
2003	10.50	$16,391.93	25.00	17.63	0.7053	1.0000	$11,560.54	$655.68
2001	12.50	$151,639.43	25.00	16.32	0.6527	1.0000	$98,974.90	$6,065.58
2000	13.50	$26,628.75	25.00	15.67	0.6270	1.0000	$16,695.77	$1,065.15
1998	15.50	$42,666.06	25.00	14.42	0.5769	1.0000	$24,612.24	$1,706.64
1996	17.50	$1,656.84	25.00	13.22	0.5287	1.0000	$875.94	$66.27
1994	19.50	$74,069.34	25.00	12.07	0.4826	1.0000	$35,746.59	$2,962.77
1993	20.50	$365,795.34	25.00	11.51	0.4604	1.0000	$168,414.31	$14,631.81
1992	21.50	$199,927.52	25.00	10.97	0.4388	1.0000	$87,719.27	$7,997.10
1991	22.50	$462,771.52	25.00	10.44	0.4177	1.0000	$193,287.90	$18,510.86
1990	23.50	$1,395,442.52	25.00	9.93	0.3971	1.0000	$554,194.95	$55,817.70
1989	24.50	$68,392.37	25.00	9.43	0.3772	1.0000	$25,795.51	$2,735.69
1988	25.50	$375,581.29	25.00	8.94	0.3577	1.0000	$134,362.46	$15,023.25
1987	26.50	$101,127.93	25.00	8.47	0.3389	1.0000	$34,267.32	$4,045.12
1986	27.50	$71,688.99	25.00	8.01	0.3205	1.0000	$22,975.41	$2,867.56
1985	28.50	$80,395.42	25.00	7.57	0.3026	1.0000	$24,330.62	$3,215.82
1984	29.50	$1,972.61	25.00	7.13	0.2853	1.0000	$562.77	$78.90
1982	31.50	$2,164.98	25.00	6.30	0.2520	1.0000	$545.67	$86.60
1981	32.50	$32,465.96	25.00	5.90	0.2361	1.0000	$7,665.92	$1,298.64
1980	33.50	$2,987.21	25.00	5.52	0.2206	1.0000	$659.11	$119.49
1979	34.50	$9,305.15	25.00	5.14	0.2056	1.0000	$1,913.23	$372.21
1978	35.50	$5,678.28	25.00	4.77	0.1910	1.0000	$1,084.50	$227.13
1975	38.50	$10,843.46	25.00	3.74	0.1496	1.0000	$1,621.85	$433.74
1974	39.50	$12,176.79	25.00	3.41	0.1365	1.0000	$1,662.61	$487.07
1973	40.50	$13,701.90	25.00	3.10	0.1239	1.0000	$1,697.41	$548.08
1972	41.50	$59,873.55	25.00	2.79	0.1116	1.0000	$6,680.11	$2,394.94
1971	42.50	$46,349.09	25.00	2.49	0.0996	1.0000	$4,615.21	$1,853.96
1970	43.50	$800.00	25.00	2.20	0.0878	1.0000	$70.26	$32.00
1969	44.50	$174,664.04	25.00	1.90	0.0762	1.0000	$13,307.48	$6,986.56

Generation Arrangement Report

Account: MTED 101/6-39020 Land/Yard Improvem
Dispersion: 25.00 - R1

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1968	45.50	$127,434.39	25.00	1.61	0.0644	1.0000	$8,206.10	$5,097.38
1967	46.50	$174,332.32	25.00	1.30	0.0520	1.0000	$9,067.55	$6,973.29
1964	49.50	$3,068.56	25.00	0.37	0.0149	1.0000	$45.84	$122.74
1963	50.50	$2,307.50	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	51.50	$3,855.39	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1961	52.50	$471.55	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1956	57.50	$5,774.43	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1955	58.50	$16,621.32	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1947	66.50	$1,865.40	25.00	0.00	0.0000	0.0000	$0.00	$0.00
		$4,340,628.36	25.00	9.61	0.3843	1.0000	$1,668,158.61	$172,389.31

Remaining Life Depreciation Accrual

Account: MTED 101/6-39020 Corp Hqtrs Reading
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - SQ
/age Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$3,890,763.60	24.26	$90,646.59	2.329789%	4.121746%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$3,890,763.60 *		$90,646.59	2.329789%	4.121746%
Average:	$3,890,763.60		$90,646.59	2.329789%	4.121746%
Grand Total:	$3,890,763.60 *		$90,646.59	2.329789%	4.121746%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39020 Corp Hqtrs Reading
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$3,890,763.60	$1,691,535.60	0.4348	$2,199,228.00	0.5652
Computed	$3,890,763.60	$1,982,900.28	0.5096	$1,907,863.32	0.4904
Difference		($291,364.68)	-0.0749	$291,364.68	0.0749

Generation Arrangement Report

Account: MTED 101/6-39020 Corp Hqtrs Reading
Dispersion: 80.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2008	5.50	$1,606.11	30.00	24.50	0.8167	1.0000	$1,311.66	$53.54
2003	10.50	$189,493.31	35.00	24.50	0.7000	1.0000	$132,645.32	$5,414.09
2001	12.50	$3,420.00	37.00	24.50	0.6622	1.0000	$2,264.59	$92.43
2000	13.50	$75,842.85	38.00	24.50	0.6447	1.0000	$48,898.68	$1,995.86
1997	16.50	$95,210.73	41.00	24.50	0.5976	1.0000	$56,894.22	$2,322.21
1996	17.50	$83,603.00	42.00	24.50	0.5833	1.0000	$48,768.42	$1,990.55
1995	18.50	$2,338.50	43.00	24.50	0.5698	1.0000	$1,332.40	$54.38
1994	19.50	$175,536.31	44.00	24.50	0.5568	1.0000	$97,741.81	$3,989.46
1993	20.50	$444,601.76	45.00	24.50	0.5444	1.0000	$242,060.96	$9,880.04
1992	21.50	$81,073.88	46.00	24.50	0.5326	1.0000	$43,180.65	$1,762.48
1991	22.50	$816,371.40	47.00	24.50	0.5213	1.0000	$425,555.30	$17,369.60
1990	23.50	$165,312.05	48.00	24.50	0.5104	1.0000	$84,378.03	$3,444.00
1989	24.50	$137,470.15	49.00	24.50	0.5000	1.0000	$68,735.08	$2,805.51
1988	25.50	$87,797.03	50.00	24.50	0.4900	1.0000	$43,020.54	$1,755.94
1987	26.50	$605,045.66	51.00	24.50	0.4804	1.0000	$290,659.19	$11,863.64
1986	27.50	$14,389.11	52.00	24.50	0.4712	1.0000	$6,779.48	$276.71
1985	28.50	$3,055.75	53.00	24.50	0.4623	1.0000	$1,412.56	$57.66
1984	29.50	$61,879.76	54.00	24.50	0.4537	1.0000	$28,075.08	$1,145.92
1983	30.50	$14,183.37	55.00	24.50	0.4455	1.0000	$6,318.05	$257.88
1982	31.50	$3,163.38	56.00	24.50	0.4375	1.0000	$1,383.98	$56.49
1981	32.50	$504.83	57.00	24.50	0.4298	1.0000	$216.99	$8.86
1979	34.50	$3,304.44	59.00	24.50	0.4153	1.0000	$1,372.18	$56.01
1978	35.50	$106,989.74	60.00	24.50	0.4083	1.0000	$43,687.48	$1,783.16
1976	37.50	$1,780.36	62.00	24.50	0.3952	1.0000	$703.53	$28.72
1975	38.50	$741.64	63.00	24.50	0.3889	1.0000	$288.42	$11.77
1974	39.50	$9,068.02	64.00	24.50	0.3828	1.0000	$3,471.35	$141.69
1973	40.50	$72,471.28	65.00	24.50	0.3769	1.0000	$27,316.10	$1,114.94
1972	41.50	$26,800.39	66.00	24.50	0.3712	1.0000	$9,948.63	$406.07
1971	42.50	$8,843.60	67.00	24.50	0.3657	1.0000	$3,233.85	$131.99
1970	43.50	$102,537.30	68.00	24.50	0.3603	1.0000	$36,943.59	$1,507.90
1969	44.50	$8,029.39	69.00	24.50	0.3551	1.0000	$2,851.02	$116.37
1968	45.50	$14,177.80	70.00	24.50	0.3500	1.0000	$4,962.23	$202.54
1967	46.50	$49,235.02	71.00	24.50	0.3451	1.0000	$16,989.55	$693.45

Generation Arrangement Report

Account: MTED 101/6-39020 Corp Hqtrs Reading
Dispersion: 80.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1966	47.50	$104,494.80	72.00	24.50	0.3403	1.0000	$35,557.26	$1,451.32
1965	48.50	$50,958.90	73.00	24.50	0.3356	1.0000	$17,102.64	$698.07
1964	49.50	$33,910.73	74.00	24.50	0.3311	1.0000	$11,227.20	$458.25
1963	50.50	$1,768.71	75.00	24.50	0.3267	1.0000	$577.78	$23.58
1962	51.50	$297.38	76.00	24.50	0.3224	1.0000	$95.87	$3.91
1959	54.50	$595.20	79.00	24.50	0.3101	1.0000	$184.59	$7.53
1955	58.50	$3,737.79	80.00	21.50	0.2688	1.0000	$1,004.53	$46.72
1954	59.50	$229,122.17	80.00	20.50	0.2563	1.0000	$58,712.56	$2,864.03
		$3,890,763.60	49.66	24.26	0.4904	1.0000	$1,907,863.32	$78,345.29

Remaining Life Depreciation Accrual

Account: MTED 101/6-39020 Lebanon Ser Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$1,009,738.85	9.50	$23,374.12	2.314868%	10.526316%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$1,009,738.85 *		$23,374.12	2.314868%	10.526316%
Average:	$1,009,738.85		$23,374.12	2.314868%	10.526316%
Grand Total:	$1,009,738.85 *		$23,374.12	2.314868%	10.526316%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39020 Lebanon Ser Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$1,009,738.85	$787,684.70	0.7801	$222,054.15	0.2199
Computed	$1,009,738.85	$760,228.37	0.7529	$249,510.48	0.2471
Difference		$27,456.33	0.0272	($27,456.33)	-0.0272

Generation Arrangement Report

Account: MTED 101/6-39020 Lebanon Ser Ctr
Dispersion: 80.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2009	4.50	$44,544.81	14.00	9.50	0.6786	1.0000	$30,226.84	$3,181.77
2001	12.50	$47,346.47	22.00	9.50	0.4318	1.0000	$20,445.07	$2,152.11
1992	21.50	$2,819.99	31.00	9.50	0.3065	1.0000	$864.19	$90.97
1990	23.50	$145,997.58	33.00	9.50	0.2879	1.0000	$42,029.61	$4,424.17
1989	24.50	$36,451.45	34.00	9.50	0.2794	1.0000	$10,184.96	$1,072.10
1988	25.50	$91,277.33	35.00	9.50	0.2714	1.0000	$24,775.28	$2,607.92
1987	26.50	$82,111.56	36.00	9.50	0.2639	1.0000	$21,668.33	$2,280.88
1986	27.50	$40,883.30	37.00	9.50	0.2568	1.0000	$10,497.06	$1,104.95
1985	28.50	$16,092.86	38.00	9.50	0.2500	1.0000	$4,023.22	$423.50
1984	29.50	$5,751.81	39.00	9.50	0.2436	1.0000	$1,401.08	$147.48
1983	30.50	$508.21	40.00	9.50	0.2375	1.0000	$120.70	$12.71
1978	35.50	$4,435.54	45.00	9.50	0.2111	1.0000	$936.39	$98.57
1977	36.50	$838.77	46.00	9.50	0.2065	1.0000	$173.22	$18.23
1973	40.50	$64,865.72	50.00	9.50	0.1900	1.0000	$12,324.49	$1,297.31
1971	42.50	$326.10	52.00	9.50	0.1827	1.0000	$59.58	$6.27
1970	43.50	$2,356.46	53.00	9.50	0.1792	1.0000	$422.38	$44.46
1969	44.50	$489.36	54.00	9.50	0.1759	1.0000	$86.09	$9.06
1968	45.50	$3,639.67	55.00	9.50	0.1727	1.0000	$628.67	$66.18
1967	46.50	$2,095.20	56.00	9.50	0.1696	1.0000	$355.44	$37.41
1966	47.50	$505.60	57.00	9.50	0.1667	1.0000	$84.27	$8.87
1965	48.50	$416,401.06	58.00	9.50	0.1638	1.0000	$68,203.62	$7,179.33
		$1,009,738.85	38.45	9.50	0.2471	1.0000	$249,510.48	$26,264.26

Remaining Life Depreciation Accrual

Account: MTED 101/6-39020 Easton Ser Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$1,369,572.59	4.50	$116,781.75	8.526876%	22.222222%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$1,369,572.59 *		$116,781.75	8.526876%	22.222222%
Average:	$1,369,572.59		$116,781.75	8.526876%	22.222222%
Grand Total:	$1,369,572.59 *		$116,781.75	8.526876%	22.222222%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39020 Easton Ser Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$1,369,572.59	$844,054.71	0.6163	$525,517.88	0.3837
Computed	$1,369,572.59	$1,018,634.05	0.7438	$350,938.54	0.2562
Difference		($174,579.34)	-0.1275	$174,579.34	0.1275

Generation Arrangement Report

Account: MTED 101/6-39020 Easton Ser Ctr
Dispersion: 80.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2009	4.50	$53,333.60	9.00	4.50	0.5000	1.0000	$26,666.80	$5,925.96
2008	5.50	$109,364.26	10.00	4.50	0.4500	1.0000	$49,213.92	$10,936.43
2007	6.50	$289,844.21	11.00	4.50	0.4091	1.0000	$118,572.63	$26,349.47
2004	9.50	$74,575.15	14.00	4.50	0.3214	1.0000	$23,970.58	$5,326.80
2002	11.50	$46,481.00	16.00	4.50	0.2813	1.0000	$13,072.78	$2,905.06
2000	13.50	$137,643.36	18.00	4.50	0.2500	1.0000	$34,410.84	$7,646.85
1994	19.50	$66,001.38	24.00	4.50	0.1875	1.0000	$12,375.26	$2,750.06
1993	20.50	$47,433.52	25.00	4.50	0.1800	1.0000	$8,538.03	$1,897.34
1991	22.50	$2,873.08	27.00	4.50	0.1667	1.0000	$478.85	$106.41
1988	25.50	$124,462.36	30.00	4.50	0.1500	1.0000	$18,669.35	$4,148.75
1987	26.50	$132,179.26	31.00	4.50	0.1452	1.0000	$19,187.31	$4,263.85
1985	28.50	$4,475.54	33.00	4.50	0.1364	1.0000	$610.30	$135.62
1984	29.50	$32.96	34.00	4.50	0.1324	1.0000	$4.36	$0.97
1983	30.50	$4,900.00	35.00	4.50	0.1286	1.0000	$630.00	$140.00
1978	35.50	$40,031.02	40.00	4.50	0.1125	1.0000	$4,503.49	$1,000.78
1974	39.50	$2,190.96	44.00	4.50	0.1023	1.0000	$224.08	$49.79
1973	40.50	$14,353.93	45.00	4.50	0.1000	1.0000	$1,435.39	$318.98
1969	44.50	$15,274.32	49.00	4.50	0.0918	1.0000	$1,402.74	$311.72
1968	45.50	$31,040.73	50.00	4.50	0.0900	1.0000	$2,793.67	$620.81
1965	48.50	$3,748.35	53.00	4.50	0.0849	1.0000	$318.26	$70.72
1964	49.50	$3,515.68	54.00	4.50	0.0833	1.0000	$292.97	$65.11
1963	50.50	$165,817.92	55.00	4.50	0.0818	1.0000	$13,566.92	$3,014.87
		$1,369,572.59	17.56	4.50	0.2562	1.0000	$350,938.54	$77,986.34

Remaining Life Depreciation Accrual

Account: MTED 101/6-39020 York Ser Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$1,855,578.29	15.42	$46,965.10	2.531022%	6.484446%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$1,855,578.29 *		$46,965.10	2.531022%	6.484446%
Average:	$1,855,578.29		$46,965.10	2.531022%	6.484446%
Grand Total:	$1,855,578.29 *		$46,965.10	2.531022%	6.484446%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39020 York Ser Ctr
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 80 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$1,855,578.29	$1,131,305.23	0.6097	$724,273.06	0.3903
Computed	$1,855,578.29	$1,082,400.73	0.5833	$773,177.56	0.4167
Difference		$48,904.50	0.0264	($48,904.50)	-0.0264

Generation Arrangement Report

Account: MTED 101/6-39020 York Ser Ctr
Dispersion: 80.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2009	4.50	$67,927.29	20.00	15.50	0.7750	1.0000	$52,643.65	$3,396.36
2008	5.50	$18,006.26	21.00	15.50	0.7381	1.0000	$13,290.33	$857.44
2004	9.50	$89,821.37	25.00	15.50	0.6200	1.0000	$55,689.25	$3,592.85
2003	10.50	$33,602.62	26.00	15.50	0.5962	1.0000	$20,032.33	$1,292.41
1997	16.50	$5,862.69	32.00	15.50	0.4844	1.0000	$2,839.74	$183.21
1995	18.50	$21,413.97	34.00	15.50	0.4559	1.0000	$9,762.25	$629.82
1994	19.50	$463,090.82	35.00	15.50	0.4429	1.0000	$205,083.08	$13,231.17
1993	20.50	$221,902.70	36.00	15.50	0.4306	1.0000	$95,541.44	$6,163.96
1992	21.50	$34,890.32	37.00	15.50	0.4189	1.0000	$14,616.22	$942.98
1991	22.50	$125,774.10	38.00	15.50	0.4079	1.0000	$51,302.59	$3,309.84
1990	23.50	$231,736.66	39.00	15.50	0.3974	1.0000	$92,100.47	$5,941.97
1988	25.50	$27,818.66	41.00	15.50	0.3780	1.0000	$10,516.81	$678.50
'987	26.50	$176,896.53	42.00	15.50	0.3690	1.0000	$65,283.24	$4,211.82
1986	27.50	$5,285.14	43.00	15.50	0.3605	1.0000	$1,905.11	$122.91
1985	28.50	$27,703.98	44.00	15.50	0.3523	1.0000	$9,759.36	$629.64
1984	29.50	$4,682.02	45.00	15.50	0.3444	1.0000	$1,612.70	$104.04
1983	30.50	$6,856.49	46.00	15.50	0.3370	1.0000	$2,310.34	$149.05
1979	34.50	$9,167.39	50.00	15.50	0.3100	1.0000	$2,841.89	$183.35
1976	37.50	$26,289.91	53.00	15.50	0.2925	1.0000	$7,688.56	$496.04
1975	38.50	$4,706.82	54.00	15.50	0.2870	1.0000	$1,351.03	$87.16
1974	39.50	$54,449.11	55.00	15.50	0.2818	1.0000	$15,344.75	$989.98
1973	40.50	$4,931.00	56.00	15.50	0.2768	1.0000	$1,364.83	$88.05
1972	41.50	$1,610.12	57.00	15.50	0.2719	1.0000	$437.84	$28.25
1970	43.50	$10,995.92	59.00	15.50	0.2627	1.0000	$2,888.76	$186.37
1969	44.50	$1,987.32	60.00	15.50	0.2583	1.0000	$513.39	$33.12
1968	45.50	$1,105.85	61.00	15.50	0.2541	1.0000	$280.99	$18.13
1967	46.50	$691.96	62.00	15.50	0.2500	1.0000	$172.99	$11.16
1966	47.50	$15,757.58	63.00	15.50	0.2460	1.0000	$3,876.86	$250.12
1965	48.50	$16,049.55	64.00	15.50	0.2422	1.0000	$3,887.00	$250.77
1964	49.50	$4,355.04	65.00	15.50	0.2385	1.0000	$1,038.51	$67.00
.963	50.50	$4,165.48	66.00	15.50	0.2348	1.0000	$978.26	$63.11
1962	51.50	$1,064.55	67.00	15.50	0.2313	1.0000	$246.28	$15.89
1961	52.50	$184.00	68.00	15.50	0.2279	1.0000	$41.94	$2.71

Generation Arrangement Report

Account: MTED 101/6-39020 York Ser Ctr
Dispersion: 80.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1960	53.50	$3,025.82	69.00	15.50	0.2246	1.0000	$679.71	$43.85
1959	54.50	$3,645.28	70.00	15.50	0.2214	1.0000	$807.17	$52.08
1958	55.50	$3,994.28	71.00	15.50	0.2183	1.0000	$871.99	$56.26
1957	56.50	$3,879.23	72.00	15.50	0.2153	1.0000	$835.11	$53.88
1956	57.50	$21,556.65	73.00	15.50	0.2123	1.0000	$4,577.10	$295.30
1954	59.50	$4,120.40	75.00	15.50	0.2067	1.0000	$851.55	$54.94
1953	60.50	$79,119.34	76.00	15.50	0.2039	1.0000	$16,136.18	$1,041.04
1952	61.50	$280.97	77.00	15.50	0.2013	1.0000	$56.56	$3.65
1947	66.50	$28.66	80.00	13.50	0.1688	1.0000	$4.84	$0.36
1946	67.50	$308.77	80.00	12.50	0.1563	1.0000	$48.25	$3.86
1943	70.50	$8,942.02	80.00	9.50	0.1188	1.0000	$1,061.86	$111.78
1941	72.50	$47.48	80.00	7.50	0.0938	1.0000	$4.45	$0.59
1931	82.50	$80.56	0.00	0.00	0.0000	0.0000	$0.00	$0.00
1929	84.50	$3,678.88	0.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	87.50	$2,086.73	0.00	0.00	0.0000	0.0000	$0.00	$0.00
		$1,855,578.29	37.05	15.42	0.4167	1.0000	$773,177.56	$49,926.79

Remaining Life Depreciation Accrual

Account: MTED 101/6-39110 Office Furniture
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$16,629,980.08	3.16	$685,871.26	4.124306%	31.615735%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($1,194,710.59)	0.50	($29,867.76)	2.500000%	
Total:	$16,629,980.08 *		$656,003.50	3.944704%	30.238959%
Average:	$16,032,624.79		$656,003.50	4.091679%	41.729357%
Grand Total:	$16,629,980.08 *		$656,003.50	3.944704%	30.238959%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39110 Office Furniture
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$16,629,980.08	$14,460,581.63	0.8695	$2,169,398.45	0.1305
Computed	$16,629,980.08	$13,999,963.82	0.8419	$2,630,016.26	0.1581
Difference		$460,617.81	0.0277	($460,617.81)	-0.0277

Generation Arrangement Report

Account: MTED 101/6-39110 Office Furniture
Dispersion: 20.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$40,510.71	20.00	19.50	0.9750	1.0000	$39,497.94	$2,025.54
2012	1.50	$4,213.87	20.00	18.50	0.9250	1.0000	$3,897.83	$210.69
2011	2.50	$10,807.00	20.00	17.50	0.8750	1.0000	$9,456.13	$540.35
2009	4.50	$257,460.96	20.00	15.50	0.7750	1.0000	$199,532.24	$12,873.05
2008	5.50	$94,958.92	20.00	14.50	0.7250	1.0000	$68,845.22	$4,747.95
2007	6.50	$24,446.63	20.00	13.50	0.6750	1.0000	$16,501.48	$1,222.33
2006	7.50	$68,051.18	20.00	12.50	0.6250	1.0000	$42,531.99	$3,402.56
2005	8.50	$1,362,497.84	20.00	11.50	0.5750	1.0000	$783,436.26	$68,124.89
2004	9.50	$160,514.97	20.00	10.50	0.5250	1.0000	$84,270.36	$8,025.75
2003	10.50	$49,106.79	20.00	9.50	0.4750	1.0000	$23,325.73	$2,455.34
2002	11.50	$10,607.41	20.00	8.50	0.4250	1.0000	$4,508.15	$530.37
2001	12.50	$64,785.26	20.00	7.50	0.3750	1.0000	$24,294.47	$3,239.26
2000	13.50	$329,349.43	20.00	6.50	0.3250	1.0000	$107,038.56	$16,467.47
1999	14.50	$535,234.72	20.00	5.50	0.2750	1.0000	$147,189.55	$26,761.74
1998	15.50	$1,595,650.35	20.00	4.50	0.2250	1.0000	$359,021.33	$79,782.52
1997	16.50	$1,092,563.60	20.00	3.50	0.1750	1.0000	$191,198.63	$54,628.18
1996	17.50	$3,418,627.46	20.00	2.50	0.1250	1.0000	$427,328.43	$170,931.37
1995	18.50	$910,322.75	20.00	1.50	0.0750	1.0000	$68,274.21	$45,516.14
1994	19.50	$1,194,710.59	20.00	0.50	0.0250	1.0000	$29,867.76	$59,735.53
1993	20.50	$695,889.18	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1992	21.50	$454,144.45	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1991	22.50	$442,317.42	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1990	23.50	$561,178.24	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1989	24.50	$498,097.92	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1988	25.50	$272,101.58	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1987	26.50	$1,180,801.97	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	27.50	$394,534.16	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1985	28.50	$627,355.88	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1984	29.50	$255,054.26	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1983	30.50	$3,687.70	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1982	31.50	$6,172.52	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1981	32.50	$2,249.64	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1980	33.50	$1,967.81	20.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

Account: MTED 101/6-39110 Office Furniture
Dispersion: 20.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1979	34.50	$1,448.33	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1978	35.50	$1,222.43	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1977	36.50	$1,182.51	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1976	37.50	$1,547.51	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1975	38.50	$271.56	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1974	39.50	$711.27	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	40.50	$500.20	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	41.50	$593.88	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1971	42.50	$1,230.10	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1970	43.50	$272.52	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1969	44.50	$139.19	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1968	45.50	$131.65	20.00	0.00	0.0000	0.0000	$0.00	$0.00
'967	46.50	$78.60	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1966	47.50	$69.64	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1965	48.50	$73.66	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1964	49.50	$45.72	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1963	50.50	$64.88	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	51.50	$64.90	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1961	52.50	$68.82	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1960	53.50	$53.35	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1959	54.50	$54.15	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1958	55.50	$80.59	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1957	56.50	$61.86	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1956	57.50	$35.54	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1955	58.50	$1.52	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1954	59.50	$0.88	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1953	60.50	$0.68	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1952	61.50	$0.35	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1951	62.50	$0.50	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1950	63.50	$0.06	20.00	0.00	0.0000	0.0000	$0.00	$0.00
949	64.50	$0.06	20.00	0.00	0.0000	0.0000	$0.00	$0.00
		$16,629,980.08	20.00	3.16	0.1581	1.0000	$2,630,016.26	$561,221.02

Remaining Life Depreciation Accrual

Account: MTED 101/6-39115 Office Machines
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 10.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$5,920,633.10	0.00	$0.00	0.000000%	
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$5,920,633.10 *		$0.00	0.000000%	0.000000%
Average:	$5,920,633.10		$0.00	0.000000%	0.000000%
Grand Total:	$5,920,633.10 *		$0.00	0.000000%	

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39115 Office Machines
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 10 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$5,920,633.10	$5,920,633.10	1.0000	$0.00	0.0000
Computed	$5,920,633.10	$5,920,633.10	1.0000	$0.00	0.0000
Difference		$0.00	0.0000	$0.00	0.0000

Generation Arrangement Report

Account: MTED 101/6-39115 Office Machines
Dispersion: 10.00 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2000	13.50	$5,264.22	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1998	15.50	$239,217.03	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1997	16.50	$898,198.22	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1996	17.50	$456,266.52	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1995	18.50	$333,547.45	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1994	19.50	$109,384.16	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1993	20.50	$74,065.51	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1992	21.50	$266,082.61	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1991	22.50	$761,400.65	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1990	23.50	$122,295.80	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1989	24.50	$293,748.72	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1988	25.50	$170,041.01	10.00	0.00	0.0000	0.0000	$0.00	$0.00
'987	26.50	$1,034,119.22	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	27.50	$367,593.23	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1985	28.50	$283,464.82	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1984	29.50	$332,790.93	10.00	0.00	0.0000	0.0000	$0.00	$0.00
1983	30.50	$173,153.00	10.00	0.00	0.0000	0.0000	$0.00	$0.00
		$5,920,633.10	0.00	0.00	0.0000	1.0000	$0.00	$0.00

Remaining Life Depreciation Accrual

Account: MTED 101/6-392 Transportation equip
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 10.00 - L3
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$268,209.32	7.62	$25,747.13	9.599641%	13.126724%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($3,087.05)	0.50	($154.35)	4.999919%	
Total:	$268,209.32 *		$25,592.78	9.542093%	13.048031%
Average:	$266,665.80		$25,592.78	9.597325%	13.151526%
Grand Total:	$268,209.32 *		$25,592.78	9.542093%	13.048031%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-392 Transportation equip
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 10 - L3
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$268,209.32	$72,066.45	0.2687	$196,142.87	0.7313
Computed	$268,209.32	$63,886.21	0.2382	$204,323.11	0.7618
Difference		$8,180.24	0.0305	($8,180.24)	-0.0305

Generation Arrangement Report

Account: MTED 101/6-392 Transportation equip
Dispersion: 10.00 - L3

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$97,011.29	10.00	9.50	0.9500	1.0000	$92,160.73	$9,701.13
2010	3.50	$166,404.13	10.00	6.58	0.6577	1.0000	$109,437.19	$16,640.41
2009	4.50	$4,793.90	10.00	5.68	0.5685	1.0000	$2,725.20	$479.39
		$268,209.32	10.00	7.62	0.7618	1.0000	$204,323.11	$26,820.93

Remaining Life Depreciation Accrual

Account: MTED 101/6-39240 Pole Trailers
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25.00 - S1
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$711,524.79	10.55	$24,374.59	3.425684%	9.480643%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($41,192.93)	0.50	($823.86)	2.000003%	
Total:	$711,524.79 *		$23,550.73	3.309897%	9.160198%
Average:	$690,928.33		$23,550.73	3.408564%	9.957940%
Grand Total:	$711,524.79 *		$23,550.73	3.309897%	9.160198%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39240 Pole Trailers
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25 - S1
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$711,524.79	$454,426.25	0.6387	$257,098.54	0.3613
Computed	$711,524.79	$411,323.71	0.5781	$300,201.08	0.4219
Difference		$43,102.54	0.0606	($43,102.54)	-0.0606

Generation Arrangement Report

Account: MTED 101/6-39240 Pole Trailers
Dispersion: 25.00 - S1
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2000	13.50	$4,952.00	25.00	13.87	0.5546	1.0000	$2,746.55	$198.08
1999	14.50	$91,590.59	25.00	13.25	0.5302	1.0000	$48,560.24	$3,663.62
1998	15.50	$49,864.56	25.00	12.67	0.5067	1.0000	$25,266.30	$1,994.58
1997	16.50	$218,827.80	25.00	12.10	0.4841	1.0000	$105,935.87	$8,753.11
1994	19.50	$74,643.07	25.00	10.53	0.4212	1.0000	$31,439.17	$2,985.72
1993	20.50	$20,312.08	25.00	10.04	0.4017	1.0000	$8,158.78	$812.48
1992	21.50	$85,257.87	25.00	9.57	0.3828	1.0000	$32,636.56	$3,410.31
1990	23.50	$70,789.02	25.00	8.67	0.3468	1.0000	$24,552.30	$2,831.56
1988	25.50	$3,874.92	25.00	7.83	0.3130	1.0000	$1,212.90	$155.00
1987	26.50	$23,064.02	25.00	7.42	0.2968	1.0000	$6,845.76	$922.56
1986	27.50	$3,500.12	25.00	7.03	0.2811	1.0000	$983.75	$140.00
1985	28.50	$3,724.85	25.00	6.64	0.2657	1.0000	$989.76	$148.99
1984	29.50	$12,644.70	25.00	6.27	0.2508	1.0000	$3,170.83	$505.79
1983	30.50	$17,629.65	25.00	5.90	0.2362	1.0000	$4,163.64	$705.19
1982	31.50	$4,232.00	25.00	5.55	0.2219	1.0000	$939.19	$169.28
1979	34.50	$4,192.44	25.00	4.53	0.1811	1.0000	$759.07	$167.70
1976	37.50	$340.00	25.00	3.57	0.1426	1.0000	$48.50	$13.60
1975	38.50	$3,131.00	25.00	3.26	0.1303	1.0000	$408.06	$125.24
1972	41.50	$5,040.33	25.00	2.37	0.0947	1.0000	$477.31	$201.61
1971	42.50	$3,043.50	25.00	2.08	0.0832	1.0000	$253.36	$121.74
1970	43.50	$6,936.97	25.00	1.80	0.0720	1.0000	$499.52	$277.48
1968	45.50	$3,057.91	25.00	1.26	0.0503	1.0000	$153.66	$122.32
1951	62.50	$875.39	25.00	0.00	0.0000	0.0000	$0.00	$0.00
		$711,524.79	25.00	10.55	0.4219	1.0000	$300,201.08	$28,425.98

Remaining Life Depreciation Accrual

Account: MTED 101/6-39250 Van Trailers
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25.00 - S1
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$87,236.99	12.08	$690.95	0.792040%	8.279192%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($3,316.17)	0.50	($66.32)	1.999897%	
Total:	$87,236.99 *		$624.63	0.716017%	7.484525%
Average:	$85,578.91		$624.63	0.729890%	9.340208%
Grand Total:	$87,236.99 *		$624.63	0.716017%	7.484525%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-39250 Van Trailers
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25 - S1
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$87,236.99	$78,891.35	0.9043	$8,345.64	0.0957
Computed	$87,236.99	$45,089.40	0.5169	$42,147.59	0.4831
Difference		$33,801.95	0.3875	($33,801.95)	-0.3875

Generation Arrangement Report

Account: MTED 101/6-39250 Van Trailers
Dispersion: 25.00 - S1

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1997	16.50	$85,895.98	25.00	12.10	0.4841	1.0000	$41,582.77	$3,435.84
1994	19.50	$1,341.01	25.00	10.53	0.4212	1.0000	$564.82	$53.64
		$87,236.99	25.00	12.08	0.4831	1.0000	$42,147.59	$3,489.48

Remaining Life Depreciation Accrual

Account: MTED 101/6-393 Stores Equipment
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$1,411,421.83	1.20	$12,423.86	0.880237%	83.491759%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($104,649.50)	0.50	($2,616.24)	2.500002%	
Total:	$1,411,421.83 *		$9,807.62	0.694875%	65.909903%
Average:	$1,359,097.08		$9,807.62	0.721627%	-26.192475%
Grand Total:	$1,411,421.83 *		$9,807.62	0.694875%	65.909903%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-393 Stores Equipment
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Depreciation Reserve Amount	Ratio	Net Plant Amount	Ratio
Recorded	$1,411,421.83	$1,396,541.49	0.9895	$14,880.34	0.0105
Computed	$1,411,421.83	$1,326,897.21	0.9401	$84,524.62	0.0599
Difference		$69,644.28	0.0493	($69,644.28)	-0.0493

Generation Arrangement Report

Account: MTED 101/6-393 Stores Equipment
Dispersion: 20.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2001	12.50	$25,412.19	20.00	7.50	0.3750	1.0000	$9,529.57	$1,270.61
2000	13.50	$17,476.87	20.00	6.50	0.3250	1.0000	$5,679.98	$873.84
1999	14.50	$210,539.16	20.00	5.50	0.2750	1.0000	$57,898.27	$10,526.96
1998	15.50	$35,405.13	20.00	4.50	0.2250	1.0000	$7,966.15	$1,770.26
1995	18.50	$11,125.41	20.00	1.50	0.0750	1.0000	$834.41	$556.27
1994	19.50	$104,649.50	20.00	0.50	0.0250	1.0000	$2,616.24	$5,232.48
1993	20.50	$14,066.18	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1992	21.50	$66,247.42	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1991	22.50	$55,762.99	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1990	23.50	$579,497.73	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1989	24.50	$37,020.70	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1988	25.50	$20,603.17	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1987	26.50	$32,459.04	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	27.50	$30,501.80	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1985	28.50	$12,114.16	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1984	29.50	$62,704.66	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1983	30.50	$28,272.74	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1982	31.50	$7,548.84	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1981	32.50	$2,555.51	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1980	33.50	$385.22	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1978	35.50	$1,355.68	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1977	36.50	$14,277.23	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1976	37.50	$5,568.81	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1975	38.50	$2,290.95	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1974	39.50	$7,485.81	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	40.50	$4,979.85	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	41.50	$7,858.35	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1971	42.50	$467.88	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1970	43.50	$2,132.94	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1969	44.50	$3,902.48	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1968	45.50	$4,195.27	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1967	46.50	$2,558.16	20.00	0.00	0.0000	0.0000	$0.00	$0.00
		$1,411,421.83	20.00	1.20	0.0599	1.0000	$84,524.62	$20,230.41

05/30/2014

Remaining Life Depreciation Accrual

Account: MTED 101/6-394 Tools shop garage
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$11,612,990.40	10.38	$487,026.48	4.193808%	9.631497%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($446,051.26)	0.50	($8,921.03)	2.000001%	
Total:	$11,612,990.40 *		$478,105.45	4.116988%	9.455074%
Average:	$11,389,964.77		$478,105.45	4.197603%	9.891339%
Grand Total:	$11,612,990.40 *		$478,105.45	4.116988%	9.455074%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-394 Tools shop garage
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 25 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$11,612,990.40	$6,556,388.32	0.5646	$5,056,602.08	0.4354
Computed	$11,612,990.40	$6,790,068.06	0.5847	$4,822,922.34	0.4153
Difference		($233,679.74)	-0.0201	$233,679.74	0.0201

Generation Arrangement Report

Account: MTED 101/6-394 Tools shop garage
Dispersion: 25.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$1,755,350.68	25.00	24.50	0.9800	1.0000	$1,720,243.67	$70,214.03
2012	1.50	$158,090.37	25.00	23.50	0.9400	1.0000	$148,604.95	$6,323.61
2011	2.50	$146,279.76	25.00	22.50	0.9000	1.0000	$131,651.78	$5,851.19
2010	3.50	$368,739.77	25.00	21.50	0.8600	1.0000	$317,116.20	$14,749.59
2009	4.50	$169,945.22	25.00	20.50	0.8200	1.0000	$139,355.08	$6,797.81
2008	5.50	$930,814.00	25.00	19.50	0.7800	1.0000	$726,034.92	$37,232.56
2007	6.50	$79,065.30	25.00	18.50	0.7400	1.0000	$58,508.32	$3,162.61
2006	7.50	$301,929.84	25.00	17.50	0.7000	1.0000	$211,350.89	$12,077.19
2005	8.50	($34,203.54)	25.00	16.50	0.6600	1.0000	($22,574.34)	($1,368.14)
2003	10.50	$152,361.45	25.00	14.50	0.5800	1.0000	$88,369.64	$6,094.46
2002	11.50	$201,085.58	25.00	13.50	0.5400	1.0000	$108,586.21	$8,043.42
2001	12.50	$392,750.60	25.00	12.50	0.5000	1.0000	$196,375.30	$15,710.02
2000	13.50	$338,417.49	25.00	11.50	0.4600	1.0000	$155,672.05	$13,536.70
1999	14.50	$163,512.10	25.00	10.50	0.4200	1.0000	$68,675.08	$6,540.48
1998	15.50	$1,086,128.46	25.00	9.50	0.3800	1.0000	$412,728.81	$43,445.14
1997	16.50	$307,177.56	25.00	8.50	0.3400	1.0000	$104,440.37	$12,287.10
1996	17.50	$163,182.73	25.00	7.50	0.3000	1.0000	$48,954.82	$6,527.31
1995	18.50	$184,446.60	25.00	6.50	0.2600	1.0000	$47,956.12	$7,377.86
1994	19.50	$185,679.97	25.00	5.50	0.2200	1.0000	$40,849.59	$7,427.20
1993	20.50	$220,993.69	25.00	4.50	0.1800	1.0000	$39,778.86	$8,839.75
1992	21.50	$216,563.32	25.00	3.50	0.1400	1.0000	$30,318.86	$8,662.53
1991	22.50	$157,912.55	25.00	2.50	0.1000	1.0000	$15,791.26	$6,316.50
1990	23.50	$420,214.40	25.00	1.50	0.0600	1.0000	$25,212.86	$16,808.58
1989	24.50	$446,051.26	25.00	0.50	0.0200	1.0000	$8,921.03	$17,842.05
1988	25.50	$195,036.42	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1987	26.50	$372,831.89	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	27.50	$315,949.61	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1985	28.50	$373,676.09	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1984	29.50	$279,597.05	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1983	30.50	$197,066.35	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1982	31.50	$105,742.51	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1981	32.50	$32,811.39	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1980	33.50	$31,356.78	25.00	0.00	0.0000	0.0000	$0.00	$0.00

Generation Arrangement Report

Account: MTED 101/6-394 Tools shop garage
Dispersion: 25.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1979	34.50	$135,221.17	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1978	35.50	$114,335.27	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1977	36.50	$101,886.74	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1976	37.50	$72,666.38	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1975	38.50	$29,718.10	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1974	39.50	$102,542.42	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	40.50	$141,435.09	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	41.50	$55,326.82	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1971	42.50	$37,314.04	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1970	43.50	$45,792.78	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1969	44.50	$62,983.18	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1968	45.50	$48,908.46	25.00	0.00	0.0000	0.0000	$0.00	$0.00
'967	46.50	$43,432.96	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1966	47.50	$71,723.98	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1965	48.50	$39,015.13	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1964	49.50	$44,296.39	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1963	50.50	$32,575.40	25.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	51.50	$17,258.84	25.00	0.00	0.0000	0.0000	$0.00	$0.00
		$11,612,990.40	25.00	10.38	0.4153	1.0000	$4,822,922.34	$340,499.57

Remaining Life Depreciation Accrual

Account: MTED 101/6-395 Laboratory equip
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$3,047,683.99	0.85	$32.18	0.001056%	100.000000%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($32,802.91)	0.50	($820.07)	2.499992%	
Total:	$3,047,683.99 *		($787.89)	-0.025852%	2448.384089%
Average:	$3,031,282.54		($787.89)	-0.025992%	4.813225%
Grand Total:	$3,047,683.99 *		($787.89)	-0.025852%	2448.384089%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-395 Laboratory equip
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$3,047,683.99	$3,047,651.81	1.0000	$32.18	0.0000
Computed	$3,047,683.99	$2,918,725.52	0.9577	$128,958.47	0.0423
Difference		$128,926.29	0.0423	($128,926.29)	-0.0423

Generation Arrangement Report

Account: MTED 101/6-395 Laboratory equip
Dispersion: 20.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2009	4.50	($918.29)	20.00	15.50	0.7750	1.0000	($711.67)	($45.91)
2008	5.50	$86,620.60	20.00	14.50	0.7250	1.0000	$62,799.94	$4,331.03
2000	13.50	$698.02	20.00	6.50	0.3250	1.0000	$226.86	$34.90
1997	16.50	$159,740.25	20.00	3.50	0.1750	1.0000	$27,954.54	$7,987.01
1996	17.50	$234,523.10	20.00	2.50	0.1250	1.0000	$29,315.39	$11,726.16
1995	18.50	$114,044.69	20.00	1.50	0.0750	1.0000	$8,553.35	$5,702.23
1994	19.50	$32,802.91	20.00	0.50	0.0250	1.0000	$820.07	$1,640.15
1993	20.50	$96,728.35	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1992	21.50	$128,933.21	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1991	22.50	$232,205.59	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1990	23.50	$204,185.93	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1989	24.50	$162,751.76	20.00	0.00	0.0000	0.0000	$0.00	$0.00
'988	25.50	$274,767.81	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1987	26.50	$403,783.63	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	27.50	$228,915.36	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1985	28.50	$86,047.11	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1984	29.50	$257,305.72	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1983	30.50	$148,714.64	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1982	31.50	$17,913.69	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1981	32.50	$6,777.40	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1980	33.50	$8,278.86	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1979	34.50	$45,555.79	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1978	35.50	$38,959.12	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1977	36.50	$1,973.32	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1976	37.50	$10,601.33	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1975	38.50	$7,441.27	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1974	39.50	$16,355.06	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1973	40.50	$11,733.40	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	41.50	$6,889.08	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1971	42.50	$5,901.54	20.00	0.00	0.0000	0.0000	$0.00	$0.00
.970	43.50	$11,018.24	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1969	44.50	$6,435.50	20.00	0.00	0.0000	0.0000	$0.00	$0.00
		$3,047,683.99	20.00	0.85	0.0423	1.0000	$128,958.47	$31,375.56

Remaining Life Depreciation Accrual

Account: MTED 101/6-396 Power operated equip
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20.00 - L0.5
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$751,657.85	10.79	$12,934.64	1.720815%	9.265490%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($58,689.67)	0.50	($1,467.24)	2.499997%	
Total:	$751,657.85 *		$11,467.40	1.525615%	8.214460%
Average:	$722,313.02		$11,467.40	1.587595%	10.400767%
Grand Total:	$751,657.85 *		$11,467.40	1.525615%	8.214460%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-396 Power operated equip
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20 - L0.5
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$751,657.85	$612,057.66	0.8143	$139,600.19	0.1857
Computed	$751,657.85	$346,035.59	0.4604	$405,622.26	0.5396
Difference		$266,022.07	0.3539	($266,022.07)	-0.3539

Generation Arrangement Report

Account: MTED 101/6-396 Power operated equip
Dispersion: 20.00 - L0.5

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$108,843.59	20.00	19.56	0.9778	1.0000	$106,429.70	$5,442.18
2007	6.50	$12,318.22	20.00	15.51	0.7755	1.0000	$9,552.83	$615.91
2002	11.50	$75,143.40	20.00	13.29	0.6647	1.0000	$49,951.06	$3,757.17
2001	12.50	$36,996.86	20.00	12.92	0.6460	1.0000	$23,901.48	$1,849.84
2000	13.50	$96,540.56	20.00	12.56	0.6279	1.0000	$60,614.26	$4,827.03
1998	15.50	($35,656.68)	20.00	11.86	0.5930	1.0000	($21,144.81)	($1,782.83)
1996	17.50	$23,509.02	20.00	11.20	0.5600	1.0000	$13,165.82	$1,175.45
1993	20.50	$140,207.69	20.00	10.28	0.5139	1.0000	$72,046.51	$7,010.38
1991	22.50	$887.85	20.00	9.70	0.4852	1.0000	$430.75	$44.39
1988	25.50	$6,437.00	20.00	8.90	0.4449	1.0000	$2,863.99	$321.85
1986	27.50	$11,289.00	20.00	8.40	0.4200	1.0000	$4,740.95	$564.45
1982	31.50	$27,454.00	20.00	7.48	0.3741	1.0000	$10,270.27	$1,372.70
1979	34.50	$2,226.00	20.00	6.86	0.3431	1.0000	$763.74	$111.30
1978	35.50	$31,361.56	20.00	6.67	0.3334	1.0000	$10,457.33	$1,568.08
1977	36.50	$34,320.49	20.00	6.48	0.3241	1.0000	$11,122.46	$1,716.02
1974	39.50	$604.00	20.00	5.96	0.2979	1.0000	$179.95	$30.20
1973	40.50	$26,241.51	20.00	5.80	0.2899	1.0000	$7,606.41	$1,312.08
1972	41.50	$88,746.00	20.00	5.64	0.2821	1.0000	$25,037.16	$4,437.30
1971	42.50	$64,187.78	20.00	5.49	0.2747	1.0000	$17,632.38	$3,209.39
		$751,657.85	20.00	10.79	0.5396	1.0000	$405,622.26	$37,582.89

Remaining Life Depreciation Accrual

Account: MTED 101/6-397 Communication Equipt
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20.00 - R0.5
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$33,964,326.46	10.06	$1,023,303.82	3.012878%	9.941215%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($1,989,229.01)	0.50	($49,730.73)	2.500000%	
Total:	$33,964,326.46 *		$973,573.09	2.866458%	9.458089%
Average:	$32,969,711.96		$973,573.09	2.952932%	10.469727%
Grand Total:	$33,964,326.46 *		$973,573.09	2.866458%	9.458089%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-397 Communication Equipt
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20 - R0.5
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$33,964,326.46	$23,670,777.27	0.6969	$10,293,549.19	0.3031
Computed	$33,964,326.46	$16,881,742.30	0.4970	$17,082,584.16	0.5030
Difference		$6,789,034.97	0.1999	($6,789,034.97)	-0.1999

Generation Arrangement Report

Account: MTED 101/6-397 Communication Equipt
Dispersion: 20.00 - R0.5
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$1,254,003.90	20.00	19.69	0.9845	1.0000	$1,234,543.39	$62,700.20
2012	1.50	$116.24	20.00	19.07	0.9536	1.0000	$110.85	$5.81
2011	2.50	$161,097.25	20.00	18.46	0.9229	1.0000	$148,683.22	$8,054.86
2010	3.50	$205,964.33	20.00	17.85	0.8925	1.0000	$183,820.10	$10,298.22
2009	4.50	$3,088,976.98	20.00	17.24	0.8622	1.0000	$2,663,408.37	$154,448.85
2008	5.50	$1,574,554.25	20.00	16.64	0.8321	1.0000	$1,310,233.59	$78,727.71
2005	8.50	$90,166.59	20.00	14.86	0.7429	1.0000	$66,981.81	$4,508.33
2002	11.50	$244,698.70	20.00	13.12	0.6558	1.0000	$160,483.41	$12,234.94
2001	12.50	$104,311.65	20.00	12.55	0.6275	1.0000	$65,460.78	$5,215.58
2000	13.50	$519,159.05	20.00	11.99	0.5997	1.0000	$311,349.42	$25,957.95
1999	14.50	$101,351.31	20.00	11.45	0.5724	1.0000	$58,010.00	$5,067.57
1998	15.50	$1,530,328.61	20.00	10.91	0.5455	1.0000	$834,864.35	$76,516.43
'997	16.50	$950,150.44	20.00	10.39	0.5193	1.0000	$493,394.91	$47,507.52
1996	17.50	($1,926,514.18)	20.00	9.87	0.4936	1.0000	($950,863.06)	($96,325.71)
1995	18.50	$10,229,039.42	20.00	9.37	0.4684	1.0000	$4,791,719.24	$511,451.97
1994	19.50	$309,972.84	20.00	8.88	0.4439	1.0000	$137,597.47	$15,498.64
1993	20.50	$809,280.72	20.00	8.40	0.4199	1.0000	$339,847.65	$40,464.04
1992	21.50	$9,074,733.78	20.00	7.93	0.3965	1.0000	$3,598,409.31	$453,736.69
1991	22.50	$664,286.24	20.00	7.47	0.3737	1.0000	$248,235.24	$33,214.31
1990	23.50	$2,344,324.93	20.00	7.03	0.3514	1.0000	$823,759.43	$117,216.25
1989	24.50	$871,137.12	20.00	6.59	0.3296	1.0000	$287,101.80	$43,556.86
1988	25.50	$210,108.28	20.00	6.16	0.3082	1.0000	$64,763.34	$10,505.41
1987	26.50	$53,352.94	20.00	5.75	0.2873	1.0000	$15,330.25	$2,667.65
1986	27.50	$211,458.29	20.00	5.34	0.2668	1.0000	$56,418.85	$10,572.91
1985	28.50	$199,330.05	20.00	4.93	0.2466	1.0000	$49,155.83	$9,966.50
1984	29.50	$94,236.58	20.00	4.53	0.2266	1.0000	$21,358.12	$4,711.83
1983	30.50	$103,298.41	20.00	4.14	0.2068	1.0000	$21,365.65	$5,164.92
1982	31.50	$27,098.35	20.00	3.74	0.1871	1.0000	$5,069.78	$1,354.92
1981	32.50	$15,995.84	20.00	3.35	0.1673	1.0000	$2,675.43	$799.79
1980	33.50	$11,286.51	20.00	2.94	0.1472	1.0000	$1,661.48	$564.33
.979	34.50	$188,830.96	20.00	2.54	0.1268	1.0000	$23,937.05	$9,441.55
1978	35.50	$48,736.90	20.00	2.11	0.1057	1.0000	$5,153.04	$2,436.85
1977	36.50	$82,488.23	20.00	1.68	0.0839	1.0000	$6,923.18	$4,124.41

Generation Arrangement Report

Account: MTED 101/6-397 Communication Equipt
Dispersion: 20.00 - R0.5

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
1976	37.50	$4,953.43	20.00	1.23	0.0613	1.0000	$303.67	$247.67
1975	38.50	$16,229.07	20.00	0.77	0.0384	1.0000	$622.80	$811.45
1974	39.50	$39,907.58	20.00	0.35	0.0174	1.0000	$694.43	$1,995.38
1973	40.50	$58,242.70	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1972	41.50	$150,401.68	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1971	42.50	$50,491.08	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1970	43.50	$2,793.19	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1969	44.50	$32,425.78	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1968	45.50	$18,301.74	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1967	46.50	$7,997.61	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1966	47.50	$16,615.59	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1965	48.50	$25,429.47	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1964	49.50	$17,911.66	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1963	50.50	$40,255.19	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1962	51.50	$4,911.73	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1961	52.50	$65.01	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1960	53.50	$5,474.48	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1959	54.50	$1,070.15	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1958	55.50	$101.78	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1957	56.50	$187.09	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1956	57.50	$1,378.86	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1955	58.50	$1,899.18	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1954	59.50	$1,704.79	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1953	60.50	$827.16	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1951	62.50	$1,825.22	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1950	63.50	$2,832.59	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1948	65.50	$12,189.30	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1947	66.50	$487.04	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1935	78.50	$30.93	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1926	87.50	$23.87	20.00	0.00	0.0000	0.0000	$0.00	$0.00
		$33,964,326.46	20.00	10.06	0.5030	1.0000	$17,082,584.16	$1,675,422.58

Remaining Life Depreciation Accrual

Account: MTED 101/6-398 Miscellaneous equipt
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20.00 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$2,586,559.95	2.03	$47,540.14	1.837968%	49.226189%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($65,392.51)	0.50	($1,634.81)	2.499996%	
Total:	$2,586,559.95 *		$45,905.33	1.774764%	47.533399%
Average:	$2,553,863.70		$45,905.33	1.797486%	71.863348%
Grand Total:	$2,586,559.95 *		$45,905.33	1.774764%	47.533399%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED 101/6-398 Miscellaneous equipt
Scenario: Met Ed 2014 ADR Gen'l Plant
Dispersion: 20 - SQ
Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$2,586,559.95	$2,489,985.05	0.9627	$96,574.90	0.0373
Computed	$2,586,559.95	$2,323,838.02	0.8984	$262,721.93	0.1016
Difference		$166,147.03	0.0642	($166,147.03)	-0.0642

Generation Arrangement Report

Account: MTED 101/6-398 Miscellaneous equipt
Dispersion: 20.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%
Broad Group Procedure
January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$11,519.21	20.00	19.50	0.9750	1.0000	$11,231.23	$575.96
2012	1.50	$886.89	20.00	18.50	0.9250	1.0000	$820.37	$44.34
2011	2.50	$30,044.90	20.00	17.50	0.8750	1.0000	$26,289.29	$1,502.25
2007	6.50	$6,932.76	20.00	13.50	0.6750	1.0000	$4,679.61	$346.64
2003	10.50	$9,290.69	20.00	9.50	0.4750	1.0000	$4,413.08	$464.53
2002	11.50	$32,453.36	20.00	8.50	0.4250	1.0000	$13,792.68	$1,622.67
2001	12.50	$4,923.43	20.00	7.50	0.3750	1.0000	$1,846.29	$246.17
2000	13.50	$279,555.58	20.00	6.50	0.3250	1.0000	$90,855.56	$13,977.78
1999	14.50	$225,999.68	20.00	5.50	0.2750	1.0000	$62,149.91	$11,299.98
1998	15.50	$32,633.98	20.00	4.50	0.2250	1.0000	$7,342.65	$1,631.70
1997	16.50	$130,458.16	20.00	3.50	0.1750	1.0000	$22,830.18	$6,522.91
1996	17.50	$106,909.66	20.00	2.50	0.1250	1.0000	$13,363.71	$5,345.48
1995	18.50	$19,634.24	20.00	1.50	0.0750	1.0000	$1,472.57	$981.71
1994	19.50	$65,392.51	20.00	0.50	0.0250	1.0000	$1,634.81	$3,269.63
1993	20.50	$123,377.94	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1992	21.50	$7,878.45	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1991	22.50	$386,470.24	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1990	23.50	$133,275.60	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1989	24.50	$170,813.56	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1988	25.50	$151,319.90	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1987	26.50	$105,251.18	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1986	27.50	$49,320.40	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1985	28.50	$72,198.35	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1984	29.50	$271,649.70	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1983	30.50	$30,104.60	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1982	31.50	$81,890.19	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1981	32.50	$1,948.05	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1980	33.50	$19,354.88	20.00	0.00	0.0000	0.0000	$0.00	$0.00
1979	34.50	$25,071.86	20.00	0.00	0.0000	0.0000	$0.00	$0.00
		$2,586,559.95	20.00	2.03	0.1016	1.0000	$262,721.93	$47,831.75

Remaining Life Depreciation Accrual

Account: MTED-101/6-39120
Scenario: Met Ed 2014 ADR 39120 PC
Dispersion: 4.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$2,194,187.95	0.84	$147,502.86	6.722435%	100.000000%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($275,835.27)	0.50	($34,479.41)	12.500000%	
Total:	$2,194,187.95 *		$113,023.45	5.151038%	76.624582%
Average:	$2,056,270.32		$113,023.45	5.496527%	1179.142378%
Grand Total:	$2,194,187.95 *		$113,023.45	5.151038%	76.624582%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED-101/6-39120
Scenario: Met Ed 2014 ADR 39120 PC
Dispersion: 4 - SQ

rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$2,194,187.95	$2,046,685.09	0.9328	$147,502.86	0.0672
Computed	$2,194,187.95	$1,732,696.52	0.7897	$461,491.43	0.2103
Difference		$313,988.57	0.1431	($313,988.57)	-0.1431

Generation Arrangement Report

Account: MTED-101/6-39120
Dispersion: 4.00 - SQ

erage Net Salvage Rate: 0.00%
uture Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$188,236.27	4.00	3.50	0.8750	1.0000	$164,706.74	$47,059.07
2012	1.50	($511.50)	4.00	2.50	0.6250	1.0000	($319.69)	($127.88)
2011	2.50	$700,333.27	4.00	1.50	0.3750	1.0000	$262,624.98	$175,083.32
2010	3.50	$275,835.27	4.00	0.50	0.1250	1.0000	$34,479.41	$68,958.82
2009	4.50	$248,107.52	4.00	0.00	0.0000	0.0000	$0.00	$0.00
2008	5.50	$782,187.12	4.00	0.00	0.0000	0.0000	$0.00	$0.00
		$2,194,187.95	4.00	0.84	0.2103	1.0000	$461,491.43	$290,973.33

Remaining Life Depreciation Accrual

Account: MTED-101/6-39125
Scenario: Met Ed 2014 ADR 39125 Info Sys
Dispersion: 10.00 - SQ
rage Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

	Plant Amt	Remaining Life	Accrual (Dollars)	Accrual Rate (Gross Plant)	Accrual Rate (Net Plant)
Pre- 2014 Additions	$2,314,954.79	7.68	$301,710.32	13.033098%	13.022402%
2014 Additions	$0.00	0.00	$0.00	0.000000%	
2014 Retirements	($0.00)	0.50	($0.00)	0.000000%	
Total:	$2,314,954.79 *		$301,710.32	13.033098%	13.022402%
Average:	$2,314,954.79		$301,710.32	13.033098%	13.022402%
Grand Total:	$2,314,954.79 *		$301,710.32	13.033098%	13.022402%

* Excluding 2014 Retirements

Depreciation Reserve Summary

Account: MTED-101/6-39125
Scenario: Met Ed 2014 ADR 39125 Info Sys
Dispersion: 10 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1 , 2014

		Depreciation Reserve		Net Plant	
	Plant Amt	Amount	Ratio	Amount	Ratio
Recorded	$2,314,954.79	($1,901.39)	-0.0008	$2,316,856.18	1.0008
Computed	$2,314,954.79	$537,283.62	0.2321	$1,777,671.17	0.7679
Difference		($539,185.01)	-0.2329	$539,185.01	0.2329

Generation Arrangement Report

Account: MTED-101/6-39125
Dispersion: 10.00 - SQ

Average Net Salvage Rate: 0.00%
Future Net Salvage Rate: 0.00%

Broad Group Procedure

January 1, 2014

Vintage	Age	Surviving Plant	Avg Life	Remaining Life	Net Plant Ratio	Alloc Factor	Computed Net Plant	Accrual
2013	0.50	$207,275.38	10.00	9.50	0.9500	1.0000	$196,911.61	$20,727.54
2011	2.50	$2,107,679.41	10.00	7.50	0.7500	1.0000	$1,580,759.56	$210,767.94
		$2,314,954.79	10.00	7.68	0.7679	1.0000	$1,777,671.17	$231,495.48

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT VI-A:

"Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

A. Balance sheet in the form available."

RESPONSE:

See Met-Ed Exhibit RAD-54 Attachment A.

Metropolitan Edison Company
Balance Sheet

FERC Account	Assets and Other Debits	April 30, 2016	March 31, 2015	March 31, 2014	March 31, 2013
			(In thousands)		
	Utility Plant				
101-107	Total electric utility plant at original cost	$ 3,012,033	$ 2,890,357	$ 2,773,905	$ 2,703,573
108-110	Less: Accum. Provision for depreciation	1,055,494	1,001,528	959,316	929,077
120.1-120.4	Nuclear plant	-	-	-	-
120.5	Less: accum. provision for amortization of nuclear fuel	-	-	-	-
	Net utility plant	1,956,539	1,888,829	1,814,589	1,774,496
	Other Property and Investments				
121	Non-utility property	1,224	1,224	1,224	1,224
122	Prov. for depreciation of non-utility prop.	464	446	429	412
123.1	Investments in subsidiary companies	-	-	-	-
124	Other investments	49	49	59	46
125-8	Special funds	328,928	328,928	328,859	321,624
	Total other property and investments	329,737	329,755	329,713	322,482
	Current and Accrued Assets				
131	Cash	-	-	-	-
132-134	Special deposits	158	158	158	157
135	Working funds	-	-	-	-
136	Temporary cash investments	-	-	-	-
142	Customer accounts receivable	123,043	124,667	126,615	94,741
143	Other accounts receivable	6,040	6,040	6,893	7,770
144	Accum. provision for uncollectible accts	5,725	5,725	7,408	3,505
145	Notes receivable from associated companies	66,908	94,604	-	-
146	Receivables from associated companies	28,041	28,041	42,691	1,071
151	Fuel stock	-	-	-	-
154-163	Plant materials and operating supplies-electric	728	728	-	-
165	Prepayments	22,256	22,257	21,798	35,792
171	Interest and dividends receivable	-	-	-	-
172	Rents receivable	7,688	7,688	8,614	7,937
173	Accrued utility revenues	43,658	43,658	40,114	38,515
174	Misc. current and accrued assets	17,085	17,085	633	997
	Total current and accrued assets	309,880	339,201	240,106	183,475
	Deferred Debits				
181	Unamortized debt expense	5,278	6,218	3,603	3,786
182	Other regulatory assets	253,521	279,108	286,827	484,968
183	Preliminary survey and investigation charges	575	575	584	564
184	Clearing accounts	-	-	-	-
185	Temporary facilities	1,688	1,168	662	671
186	Miscellaneous deferred debits	413,016	406,667	427,254	427,365
188	Research and development expenditures	351	351	351	351
189	Unamortized loss on reacquired debt	1,720	-	2,382	4,025
190	Accumulated deferred income taxes	452,973	454,272	471,353	251,370
	Total deferred debits	1,129,121	1,148,360	1,193,015	1,173,100
	Total assets and other debits	$ 3,725,277	$ 3,706,144	$ 3,577,422	$ 3,453,553

Metropolitan Edison Company
Balance Sheet

FERC Account	Liabilities and Other Credits	April 30, 2016	March 31, 2015	March 31, 2014	March 31, 2013
			(In thousands)		
	Proprietary Capital				
201	Common stock issued	$ 827,802	$ 827,802	$ 827,740	$ 767,489
204	Preferred stock issued	-	-	-	-
207	Premium on capital stock	-	-	-	-
208	Other paid in capital	93	93	116	-
210	Gain on resale or cancellation of reacquired capital stock	-	-	-	-
214	Capital stock expense	-	-	-	-
216	Retained earnings	(10,133)	(12,550)	(22,115)	224
216.1	Unappropriated Undistributed Subsidiary Earnings	-	-	-	-
219	Accumulated other comprehensive income	(370)	3,770	12,150	21,172
	Total proprietary capital	817,392	819,114	817,892	788,885
	Long-Term Debt				
221	Bonds	200,000	200,000	28,500	28,500
224	Other long-term debt	750,000	750,000	750,000	850,000
225	Unamortized premium on long-term debt	-	-	-	-
226	Less: Unamortized discount on long-term debt	293	339	382	501
	Total long-term debt	949,707	949,661	778,118	877,999
227-230	**Other Non-Current Liabilities**	352,596	345,118	353,112	357,393
	Current and Accrued Liabilities	-	-	-	-
231	Notes payable	50,000	50,000	75,000	-
232	Accounts payable	56,468	56,468	55,449	21,031
233	Notes payable to associated companies	-	-	61,845	91,306
234	Accounts payable to associated companies	30,645	30,645	50,478	77,055
235	Customer deposits	20,925	20,925	21,452	15,044
236	Taxes accrued	45,237	54,998	9,811	16,208
237	Interest accrued	30,578	16,269	9,198	11,587
238	Dividends declared	-	-	-	-
241	Tax collections payable	348	348	390	342
242	Misc. current and accrued liabilities	15,253	17,291	19,942	16,171
243	Oblig. under capital leases-current	2,983	2,983	2,991	2,408
	Total current and accrued liabilities	252,437	249,926	306,556	251,152
	Deferred Credits				
252	Customer advances for construction	19	19	19	63
253	Other deferred credits	164,297	164,537	136,035	145,792
254	Other regulatory liabilities	145,564	137,494	140,450	136,772
255	Accum. deferred investment tax credits	4,813	5,208	5,521	5,919
256	Deferred gains on disposition of plant	-	-	-	-
257	Unamortized gain on reacquired debt	(317)	(161)	1,266	1,476
	Total deferred credits	314,376	307,096	283,292	290,022
	Accumulated Deferred Income Taxes				
282	Other property	552,440	552,220	555,752	542,609
283	Other	486,327	483,009	482,701	345,493
	Total accum. deferred income taxes	1,038,767	1,035,229	1,038,453	888,102
	Total liabilities and other credits	$ 3,725,277	$ 3,706,144	$ 3,577,422	$ 3,453,553

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT VI-B:

"Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

B. Statement of income."

RESPONSE:

See Met-Ed Exhibit RAD-55 Attachment A.

Metropolitan Edison Company
Comparative Income Statements

FERC Account		April 30, 2016	March 31, 2015	2014	2013
			(In thousands)		
Operating Revenues					
Electric Service Revenues					
440	Residential sales	$ 487,124	$ 495,246	$ 557,080	$ 571,437
442	Commercial sales	112,883	123,810	131,306	152,083
442	Industrial sales	51,258	50,866	45,471	68,019
444	Public street and highway lighting	5,410	5,141	5,252	7,015
445	Other sales to public authorities		-	-	-
447	Sale for resale	12,678	21,076	26,062	32,955
	Total electric service revenues	$ 669,354	$ 696,139	$ 765,171	$ 831,510
Other Electric Revenue					
450	Forfeited discounts	$ 3,229	$ 3,229	$ 3,583	$ 3,943
451	Miscellaneouse service revenues	1,903	1,903	2,246	1,596
454	Rent from electric property	19,477	19,477	19,477	19,679
456	Other electric revenues	47,656	47,885	45,615	31,612
	Total other electric revenues	$ 72,265	$ 72,494	$ 70,921	$ 56,829
	Total operating revenues	$ 741,619	$ 768,633	$ 836,092	$ 888,339
Operating Expenses					
401-2	Operation and maintenance expense				
	Power production expenses	$ 275,734	$ 320,216	$ 378,228	$ 408,304
	Transmission expenses	21,154	21,730	23,071	14,314
	Regional market expenses	54	50	43	60
	Distribution expenses	37,980	33,837	48,826	48,831
	Customer accounts expense	23,271	25,286	24,842	24,195
	Customer service & information expense	40,696	44,185	39,990	51,349
	Sales expenses	25	24	15	13
	Administrative & general expenses	41,116	37,806	6,525	57,158
	Subtotal	$ 440,030	$ 483,134	$ 521,541	$ 604,223
403	Depreciation expense	$ 59,721	$ 56,892	$ 55,187	$ 69,205
404-5	Amortization and depletion of utility plant	4,710	2,681	3,006	3,130
406	Amortization and utility plant acq. adjustment		-	-	-
407	Amortization of property losses		-	-	-
407.3	Regulatory debits	22,920	24,410	35,722	212,875
407.4	Regulatory credits	15,407	(11,449)	(23,530)	(194,776)
408.1	Taxes other than income taxes	45,795	46,882	50,525	54,381
411.1	Accretion expense	49	62	58	54
411.8	Gains from disposition allowance			-	-
	Total operating expenses before federal and state income taxes	$ 588,632	$ 602,611	$ 642,508	$ 749,091
	Net operating income before income taxes	$ 152,987	$ 166,021	$ 193,584	$ 139,247
Income taxes					
409.1	Income taxes-federal	$ 39,423	$ 25,303	$ 28,956	$ (43,523)
409.1	Income taxes-state	-	-	5,701	(7,869)
410.1	Provision for deferred income taxes	49,263	67,085	131,537	259,974
411.1	Income taxes deferred in prior years-cr.	(42,966)	(39,764)	(190,653)	(166,189)
411.4	Investment tax credit adjustments-net	(364)	(364)	(397)	(421)
	Total income taxes	$ 45,356	$ 52,260	$ (24,855)	$ 41,972
	Net operating income	$ 107,631	$ 113,762	$ 218,439	$ 97,275
Other income					
415-16	Revenues from merchandising, jobbing and contract work	$ 2,808	$ 3,681	$ 1,995	$ 2,128
417	Revenues from non-utility operations			-	-
417.1	Expenses from non-utility operations			-	-
418	Nonoperating rental income	(17)	(17)	333	(17)
418.1	Equity in earnings of subsidiary companies			-	-
				-	-
419	Interest and dividend income	1,647	98	666	(9)
419.1	Allowance for funds used during construction	1,343	1,852	-	8
				-	-
421	Miscellaneous non-operating income	1,740	1,740	2,546	1,248
421.1	Gain on disposition of property			-	-

Metropolitan Edison Company
Comparative Income Statements

FERC Account		April 30, 2016	March 31, 2015	2014	2013
			(In thousands)		
	Total other income	$ 7,522	$ 7,354	$ 5,540	$ 3,358
	Gross income	$ 115,153	$ 121,115	$ 223,980	$ 100,633
Other Income Deductions					
421.2	Loss on disposition of property			$ -	$ -
425	Miscellaneous amortization			-	-
426	Other income deductions	146	146	189,014	353
	Total other income deductions	$ 146	$ 146	$ 189,014	$ 353
Taxes Applicable to Other Income and Deductions					
408.2	Taxes other than income taxes			$ -	$ -
409.2	Income taxes - federal			2,249	1,078
409.2	Income taxes - state			713	342
410.2	Provision for deferred income taxes			6	2
411.2	Provision for deferred income taxes-cr.			(26)	(18)
	Total taxes on other income and deductions	$ -	$ -	$ 2,942	$ 1,404
Interest Charges					
427	Interest on long term debt	$ 51,862	$ 40,717	$ 45,258	$ 43,803
428	Amortization of debt discount and expense	911	700	821	763
				-	-
428.1	Amortization of loss on reacquired debt	247	544	2,881	1,643
				-	-
429	Amortization of premium on debt credit			74	(294)
429.1	Amortization of gain on reacquired debt	(144)	(144)	(284)	-
430	Interest on debt to associated companies	8	1,036	2,731	3,772
431	Other interest expense	3,859	4,152	3,529	2,946
432	Allowance for borrowed funds used during construction - credit	(892)	(1,229)	(647)	(266)
				-	-
	Total interest charges	$ 55,852	$ 45,776	$ 54,364	$ 52,367
	Income before extraordinary items	$ 59,155	$ 75,194	$ (22,340)	$ 46,509
Extraordinary Items & Related Taxes					
434	Extraordinary income			$ -	$ -
435	Extraordinary deductions			-	-
409.3	Income taxes - Federal & other			-	-
	Extraordinary items after taxes	$ -	$ -	$ -	$ -
	Net income	$ 59,155	$ 75,194	$ (22,340)	$ 46,509
Power Production Expenses					
Steam Power Generation					
Operation					
501	Fuel			$ -	$ (3)
514	Maintenance of miscellaneous steam plant	3,357	1,212	339	146
	Total operation	$ 3,357	$ 1,212	$ 339	$ 143
	Total steam power generation	$ 3,357	$ 1,212	$ 339	$ 143
Nuclear Power Generation					
Operation					
518	Fuel			$ -	$ -
	Miscellaneous nuclear power expenses			-	-
	Total operation	$ -	$ -	$ -	$ -
	Total nuclear power generation	$ -	$ -	$ -	$ -
Other Power Generation					
Operation					
549	Miscellaneous other power generation expenses			-	-
	Total operation	$ -	$ -	$ -	$ -

Metropolitan Edison Company
Comparative Income Statements

FERC Account		April 30, 2016	March 31, 2015	2014	2013
			(In thousands)		
	Total other power generation	$ -	$ -	$ -	$ -
Other Power Supply Expenses					
555	Purchased Power	$ 278,084	$ 326,146	$ 379,195	$ 457,126
556	System control and load dispatching			-	-
557	Other expenses	(5,707)	(7,143)	(1,307)	(48,965)
	Total other power supply expenses	$ 272,377	$ 319,004	$ 377,888	$ 408,161
	Total power production expenses	$ 275,734	$ 320,216	$ 378,228	$ 408,304
Transmission Expenses					
Operation					
560	Operation supervision and engineering	$ 58	$ 53	$ 97	$ 21
561	Load dispatching	1,208	1,309	907	1,867
562	Station expenses	174	-	45	67
563	Overhead lines expense	33	33	16	18
564	Underground lines expenses	-	-	-	-
565	Transmission of electricity by others	11,776	12,626	12,151	2,278
566	Miscellaneous transmission expenses	1,198	1,227	466	1,228
567	Rents	472	472	453	270
	Total operation	$ 14,920	$ 15,721	$ 14,134	$ 5,748
Maintenance					
568	Maintenance supervision and engineering	$ 920	$ 880	$ 772	$ 423
569	Maintenance of structures	224	215	293	366
570	Maintenance of station equipment	2,650	2,538	1,867	1,474
571	Maintenance of overhead lines	2,347	2,284	5,922	6,248
572	Maintenance of underground lines	-	-	0	-
573	Maintenance of miscellaneous transmission plant	93	93	81 -	55 -
	Total maintenance	$ 6,234	$ 6,009	$ 8,936	$ 8,566
	Total transmission expenses	$ 21,154	$ 21,730	$ 23,071	$ 14,314
Regional Market Expenses					
Operation					
575	Operation-regional market expense	$ 54	$ 50	$ 43	$ 60
	Total operation	$ 54	$ 50	$ 43	$ 60
Maintenance					
576	Maintenance-regional market expense			$ -	$ -
	Total maintenance	$ -	$ -	$ -	$ -
	Total regional market expenses	$ 54	$ 50	$ 43	$ 60
Distribution Expenses					
Operation					
580	Operation supervision and engineering	$ 97	$ 88	$ 59	$ 354
581	Load dispatching	339	329	259	353
582	Station expenses	615	603	943	749
583	Overhead lines expense	37	37	299	31
584	Underground lines expenses	576	576	141	550
585	Street lighting and signal system expenses	-	-	(1)	(2)
586	Meter expenses	771	738	597	488
587	Customer installation expenses	-	-	-	-
588	Miiscellaneous expenses	4,949	5,077	5,213	4,948
589	Rents	541	541	555	546
	Total operation	$ 7,926	$ 7,988	$ 8,064	$ 8,016
Maintenance					
590	Maintenance supervision and engineering	$ 390	$ 353	$ 392	$ 452
591	Maintenance of structures	16	16	9	11
592	Maintenance of station equipment	4,043	3,491	2,667	2,849
593	Maintenance of overhead lines	20,233	16,670	30,983	31,106
594	Maintenance of underground lines	2,048	2,088	2,381	1,736
595	Maintenance of line transformers			-	2
596	Maintenance of street lighting and signal systems	250	247	657 -	667 -
597	Maintenance of meters	1,645	1,614	1,996	2,146

Metropolitan Edison Company
Comparative Income Statements

FERC Account		April 30, 2016	March 31, 2015	2014	2013
			(In thousands)		
598	Maintenance of miscellaneous distribution plant	1,428	1,371	1,677	1,846
				-	-
	Total maintenance	$ 30,054	$ 25,848	$ 40,762	$ 40,815
	Total distribution expenses	$ 37,980	$ 33,837	$ 48,826	$ 48,831
Customer Account Expenses					
Operation					
901	Supervision		$ -	$ 6	$ 5
902	Meter reading expenses	5,026	5,184	4,057	4,570
903	Customer records and collection expenses	5,858	5,998	6,199	6,645
904	Uncollectible accounts	12,136	13,864	14,346	12,690
905	Miscellaneous customer accounts expense	251	241	235	285
	Total customer accounts expense	$ 23,271	$ 25,286	$ 24,842	$ 24,195
Customer Service and Informational Expenses					
Operation					
907	Supervision	$ 304	$ 293	$ 206	$ 194
908	Customer assistance expenses	34,566	38,163	34,403	46,243
909	Informational and instructional expenses	130	58	1	0
910	Miscellaneous customer service and informational expenses	5,696	5,670	5,380	4,911
				-	-
	Total customer service and informational expense	$ 40,696	$ 44,185	$ 39,990	$ 51,349
Sales Expenses					
Operation					
911	Supervision			$ -	$ -
912	Demonstrating and selling expenses			-	-
913	Advertising expenses	25	24	15	13
916	Miscellaneouse sales expenses			0	-
	Total sales expenses	$ 25	$ 24	$ 15	$ 13
Administrative and general expenses					
Operation					
920	Administrative and general salaries	$ (524)	$ (363)	$ 2,858	$ 373
921	Office supplies and expense	3,155	2,908	2,599	2,268
922	Administrative expenses transferred-credit	(3,082)	(3,163)	(5,116)	(7,730)
923	Outside services employed	35,388	38,839	32,607	33,727
924	Property insurance	242	227	165	149
925	Injuries and damages	930	854	950	3,974
926	Employee pensions and benefiits	(745)	(7,111)	(33,506)	17,321
927	Franchise requirements		-	-	-
928	Regulatory commission expenses	2,632	2,469	2,460	2,761
929	Duplicate charges - credit			-	-
930.1	General advertising expenses	10	10	83	1,010
930.2	Miscellaneous general expenses	698	748	778	696
931	Rents	1,612	1,588	1,305	657
	Total administrative and general expenses	$ 40,316	$ 37,005	$ 5,183	$ 55,206
Maintenance					
935	Maintenance and general plant	801	801	1,342	1,952
	Total maintenance	$ 801	$ 801	$ 1,342	$ 1,952
	Total administrative and general expenses	$ 41,116	$ 37,806	$ 6,525	$ 57,158
	Total electric operation and maintenance expenses	$ 440,030	$ 483,134	$ 521,540	$ 604,223

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT VI-C:

"Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

C. Plant in service."

RESPONSE:

See Met-Ed Exhibit RAD-56 Attachment A.

METROPOLITAN EDISON COMPANY
Plant in Service

FERC Account		4/30/2016	3/31/2015	3/31/2014	3/31/2013
		(In thousands)			
	Intangible				
301	Organization	$ 124	$ 124	$ 124	$ 124
302	Franchises and Consents	165	165	165	165
303	Miscellaneous Intangible Plant	57,878	41,603	38,675	38,320
303	Smart Meter Software	13,104	2,160	-	-
	Total Intangible Plant	$ 71,270	$ 44,051	$ 38,964	$ 38,608
	Nuclear Production				
326	Asset Retirement Costs	$ 95,321	$ 95,321	$ 95,321	$ 95,321
	Total Nuclear Production	$ 95,321	$ 95,321	$ 95,321	$ 95,321
	Transmission Plant				
350	Fee Land - Trans. Subs.	$ 1,384	$ 1,384	$ 1,384	$ 1,384
350	Easements - Trans. Subs.	173	173	173	410
350	Fee Land - Trans. Lines	2,045	2,045	2,045	2,045
350	Easements - Trans. Lines	26,760	26,760	26,760	26,760
352	Structures, Improvements	6,475	6,475	6,475	5,744
352	Clearing, Grading Of Land	305	305	305	1,704
353	Station Equipment	210,580	194,600	183,423	166,316
354	Towers And Fixtures	41,083	41,083	41,083	41,962
355	Poles And Fixtures	46,550	46,550	46,550	43,899
356	Overhd Conductr, Devices	99,183	94,208	69,633	64,882
356	Clearing, Grading of Land	17,683	17,683	17,683	13,185
358	Undergrnd Conductr,Devices	1,191	1,191	1,191	1,024
359	Roads And Trails	747	747	747	747
359	ARC Transmission	5	5	5	5
	Total Transmission Plant	$ 454,163	$ 433,209	$ 397,456	$ 370,067
	Distribution Plant				
360	Fee Land - Dist. Subs.	$ 2,777	$ 2,777	$ 2,777	$ 2,777
360	Easements - Dist. Subs.	611	611	611	375
360	Fee Land - Dist. Lines	428	428	428	303
360	Easements - Dist. Lines	28,321	28,321	28,321	28,321
361	Structures, Improvements	12,746	12,746	12,746	12,676
361	Clearing, Grading of Land	366	366	366	130
362	Station Equipment	216,798	212,973	203,494	198,607
364	Poles, Towers And Fixtures	354,211	354,211	354,211	382,641
365	Overhd Conductr, Devices	368,193	368,193	368,193	325,681
365	Clearing, Grading of Land	131,740	131,740	131,740	122,276
366	Underground Conduit	30,297	30,297	30,297	30,229
367	Undergrnd Conductr,Devices	203,213	203,213	203,213	190,569
368	Line Transformers	502,265	450,298	392,738	388,640
369	Services	169,525	169,525	169,525	166,963
370	Meters	66,795	66,795	66,795	64,399
370	Smart Meters Res	11,620	2,241	1,554	-
371	Inst. On Cust. Prem.	4,520	4,520	4,520	4,414
373	Street Light - Oh, Ug Lines	12,289	12,289	12,289	11,516
374	ARC Distribution	37	37	37	37

METROPOLITAN EDISON COMPANY
Plant in Service

FERC Account		4/30/2016	3/31/2015	3/31/2014	3/31/2013
	Total Distribution Plant	$ 2,116,751	$ 2,051,579	$ 1,983,854	$ 1,930,555
	General Plant				
389	Fee Land	$ 2,673	$ 2,673	$ 2,673	$ 1,568
389	Easements	18	18	18	18
390	Structures, Improvements	87,469	87,468	85,738	85,320
390	Clearing, Grading of Land	12,466	12,466	12,466	12,466
390	Struct Imprv, Leasehold Imp	17	17	17	17
391	Office Furn., Mech. Equip.	16,631	16,631	16,631	17,100
391	Office Machines	5,921	5,921	5,921	5,921
391	Data Processing Equipment	4,627	4,627	4,627	2,553
391	Data Proc Smart Meters	9,299	6,356	903	-
391	Information System	(12)	(12)	(12)	0
392	Transportation Equipment	5,185	4,229	1,067	1,219
393	Stores Equipment	1,411	1,411	1,411	1,429
394	Tools, Shop, Garage Equip.	11,712	11,712	11,712	10,253
395	Laboratory Equipment	3,048	3,048	3,048	3,130
396	Power Operated Equipment	752	752	752	643
397	Communication Equipment	34,023	34,023	34,023	35,659
398	Misc. Equipment	2,587	2,587	2,587	2,671
399	ARC General Plant	106	106	106	106
	Total General Plant	$ 197,931	$ 194,032	$ 183,686	$ 180,073
	Total Plant in Service	$ 2,935,437	$ 2,818,193	$ 2,699,281	$ 2,614,625

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT VI-D:

"Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

D. Accumulated depreciation."

RESPONSE:

See Met-Ed Exhibit RAD-57 Attachment A.

Metropolitan Edison Company
Reserve for Depreciation

FERC Account	April 30,2016	March 31, 2015	March 31, 2014	March 31, 2013
		(In thousands)		
303 2002 Software	$ 1,950	$ 1,950	$ 1,950	$ 1,950
303 2003 Software	859	859	859	859
303 2004 Software	3,919	3,919	3,919	3,919
303 2005 Software	794	794	794	794
303 2006 Software	1,212	1,212	1,212	1,175
303 2007 Software	6,544	6,544	6,253	5,090
303 2008 Software	800	830	951	992
303 2009 Software	2,354	1,949	1,575	1,200
303 2010 Software	1,121	1,003	895	787
303 2011 Software	3,487	2,729	2,029	1,295
303 2012 Software	315	202	98	5
303 2013 Software	785	475	189	2
303 Proj Enterprise	622	622	622	622
303 Software	3,084	1,632	1,009	658
303 Software Evolution	8,048	8,048	8,048	8,048
303 Smart Meters	1,463	106	-	-
Intangibles Total	$ 37,357	$ 32,874	$ 30,403	$ 27,396
350.12 Tran Sub Easement	$ 110	$ 107	$ 105	$ 101
350.21 Tran Line Land	8	8	8	8
350.22 Tran Line Easement	12,274	11,839	11,438	11,036
352 Struct PCA Dist	70	68	66	64
352 Structures/improve	2,912	2,780	2,658	2,601
353 Station Eq PCA Dist	2,365	2,216	2,079	1,957
353 Station equipment	57,609	55,830	54,045	52,321
354 Towers & Fixtures	27,717	27,190	26,703	26,258
354 Towers PCA Dist	34	34	33	33
355 Poles & Fixtures	18,963	18,252	17,595	17,454
355 Poles PCA Dist	403	394	386	377
356 OH Cond PCA Dist	303	296	289	282
356 Overhead Conductor	28,367	27,579	29,184	28,877
356.10 Clearing & R/W	3,185	3,087	2,997	3,013
356.10 R/W PCA Dist	929	770	624	309
356.20 Veg Clrng-FERC exp	-	-	-	-
358 UG Cond PCA Dist	-	-	-	-
358 Undergound Conductor	130	98	69	41
359 Roads & Trails	543	525	509	492
359 Roads PCA Dist	8	8	8	7
TXM SUB ARC	3	3	3	3
Transmission total	$ 155,933	$ 151,084	$ 148,799	$ 145,234

FERC Account	April 30,2016	March 31, 2015	March 31, 2014	March 31, 2013
		(In thousands)		
360.12 Dist Sub Easement	$ 192	$ 182	$ 173	$ 165
360.22 Dist Line Easement	14,836	14,384	13,967	13,550
361 Structure/Improve	6,566	6,226	5,912	5,602
361.20 Grading Clearing	33	24	15	9
362 Station equipment	76,801	73,640	71,464	69,591
364 Poles towers fix	114,047	108,880	104,111	101,435
365 Overhead conductor	87,557	80,902	74,758	74,288
365.10 Clearing & R/W	21,120	18,941	16,929	15,025
365.10 Veg Clrng-FERC exp	-	-	-	-
366 Underground conduit	11,950	11,377	10,848	10,327
367 Undergrd conductor	78,292	72,015	66,221	62,132
368 Line Transformers	132,974	127,714	124,985	120,583
369 Services OH	21,492	19,718	18,079	16,527
369 Unground Services	51,141	48,736	46,516	44,296
370 Meters	16,632	14,728	12,085	10,867
370 Smart Meters Res	499	159	50	-
371 Inst on cust prem	2,112	1,978	1,855	1,753
371 Meter Socket dvc 125	-	-	-	-
371 Meter Socket dvc 126	-	-	-	-
371 Meter Socket dvc 127	-	-	-	-
371 Meter Socket dvc 1PH	329	315	301	288
371 Meter Socket dvc 3PH	-	-	-	-
371 Surge Suppression 2	241	241	241	241
371 Surge Suppression 4	36	36	36	36
373 Street Lighting	3,508	3,160	2,839	3,113
DIST SUB ARC	23	22	21	21
Distribution Total	$ 640,381	$ 603,378	$ 571,406	$ 549,849
389.20 Land Rights	$ 16	$ 16	$ 15	$ 15
390.10 Easton Serv Center	4,661	4,322	4,009	3,766
390.10 Lebanon Serv Ctr	3,510	3,306	3,119	3,035
390.10 South Bldg Reading	27,491	26,265	25,342	24,250
390.10 Structures	8,683	8,239	7,830	7,427
390.10 York Serv Center	4,420	4,193	3,983	3,774
390.20 Corp Hqtrs Reading	1,903	1,805	1,714	1,624
390.20 Easton Ser Ctr	1,117	990	873	756
390.20 Land/Yard Improvem	3,191	3,007	2,837	2,667
390.20 Lebanon Ser Ctr	842	817	794	770
390.20 York Ser Ctr	1,240	1,190	1,143	1,096
390.30 Transfered LH	6	5	4	3
391.10 Office Furniture	16,193	15,389	14,646	14,419
391.15 Office Machines	5,921	5,921	5,921	5,921
391.20 Personal Computers	3,883	3,029	2,240	1,965
391.25 Data Proc Smart Me	1,565	222	86	-

FERC Account	April 30,2016	March 31, 2015	March 31, 2014	March 31, 2013
		(In thousands)		
391.25 Information Sys	(12)	(7)	(3)	-
392 Transportation equip	141	109	80	52
392.40 Pole Trailers	514	486	461	435
392.50 Van Trailers	81	80	79	78
393 Stores Equipment	1,411	1,411	1,404	1,391
394 Tools shop garage	7,757	7,199	6,684	6,492
395 Laboratory equip	3,048	3,048	3,048	3,130
396 Power operated equip	622	617	613	609
397 Communication Equipt	25,656	24,596	23,914	25,011
398 Miscellaneous equipt	2,587	2,567	2,505	2,539
EASTON BLDG ARC	4	4	4	4
GEN BLDG ARC	32	31	30	28
LEBANON BLDG ARC	4	4	4	4
READING SOUTH BLDG ARC	9	8	8	8
YORK BLDG ARC	3	3	3	3
General Total	$ 126,499	$ 118,872	$ 113,390	$ 111,272
TMI#2 ARC Total	$ 95,321	$ 95,321	$ 95,321	$ 95,321
Total	$ 1,055,491	$ 1,001,529	$ 959,319	$ 929,072

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT I-A-4:

> "Whenever a major generating plant is placed in operating service or removed from operating service the utility shall separately indicate the effect of the plant addition or removal from service upon rate base, revenue, expense, tax, income and revenue requirement as it affects the test year."

RESPONSE:

This base rate case filing requirement is not applicable to the Company's filing.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT I-B-2:

"Provide a description of the property of the utility and an explanation of the system's operation, and supply the following, using available projections if actual data is unavailable

a. A schedule of generating capability showing for the test year, and for the two consecutive 12-month periods prior to the test year, net dependable capacity in KW by unit, plant capacity factor by unit, and total fuel consumption by type and cost for each unit, if available, or for each station, and operation and maintenance expenses by station.

b. A schedule showing for the test year and for the 12-month period immediately prior to the test year the scheduled and unscheduled outages—in excess of 48 hours—for each station, the equipment or unit involved, the date the outage occurred, duration of the outage, maintenance expenses incurred for each outage, if available, and amounts reimbursable from suppliers or insurance companies.

c. A schedule for each unit retired during the test year or subsequent to the end of the test year, which shows the unit's KW capacity, hours of operation during the test year, net output generated, cents/KWH of maintenance and fuel expenses, and date of retirement

d. A schedule showing latest projections of capacity additions and retirements—costs and KW—and reserve capacity at the time of peak for at least 10 years beyond the test year, including the inservice dates—actual or expected—and AFDC cutoff dates—if different from inservice dates—for all new generating units coming on line during or subsequent to the test year, if claimed."

RESPONSE:

This base rate case filing requirement is not applicable to the Company's filing.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-B-5:

"Describe long-term debt reacquisition by issue by Company and Parent as follows:

a. Reacquisition by issue by year.
b. Total gain or loss on reacquisitions by issue by year.
c. Accounting for gain or loss for income tax and book purposes.
d. Proposed treatment of gain or loss on such reacquisition for ratemaking purposes."

RESPONSE:

a. Please see Met-Ed Exhibit RAD-60 Attachment A.
b. Please see Met-Ed Exhibit RAD-60 Attachment A.

c. *Tax Accounting:*

Gains attributable to the reacquisition of long-term debt are recognized on the same basis recorded for book purposes.

Losses on the reacquisition of long-term debt are deducted currently for income tax purposes in the year of reacquisition, which creates book-tax temporary differences. As a result of these temporary differences, the Company records deferred income taxes by means of debits to Account 410.1, Provision for Deferred Income Taxes, Utility Operating Income, with corresponding credits to Account 283, Accumulated Deferred Income Taxes – Other. Amounts recorded in Account 283 are reversed over the remaining life of the respective security issue consistent with book amortization of the loss by means of credits to Account 411.1, Provision for Deferred Income Taxes – Credit, Utility Operating Income.

Book Accounting:

In accordance with General Instruction 17 of the Uniform System on Accounts, gains on reacquired debt are placed in Account No. 257 "Unamortized Gain on Reacquired Debt". The gains are then amortized to Account No. 429.1 "Amortization of Gain on Reacquired Debt-Credit" over the remaining lives of the respective issues (old original debt).

In accordance with General Instruction 17 of the Uniform System of Accounts, losses on reacquired debt are placed in Account No. 189 "Unamortized Loss on Reacquired Debt". The losses are then amortized to Account No 428.1 Amortization of Loss on Reacquired Debt" over the remaining lives of the respective issues (old original debt).

d. The amortization of gain or loss on long term debt reacquisition for ratemaking purposes is addressed on RAD-2, page 12.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-B-5

Line No.	Description	Amount	Total Gain (Loss) On Reacquired Debt	ACTUAL Unamortized Gain (Loss) as of March 31, 2013	ACTUAL Unamortized Gain (Loss) as of March 31, 2014	PROJECTED Unamortized Gain (Loss) as of March 31, 2015	PROJECTED Unamortized Gain (Loss) as of April 30, 2016
	2003						
1	7.65% First Mortgage Bond series due 5/31/2023	30,000,000	(1,103,306.63)	(560,847.63)	(505,682.29)	(450,516.95)	(390,754.50)
2	6.97% First Mortgage Bond series due 9/30/2023	30,000,000	(2,967,551.70)	(1,557,964.53)	(1,409,586.96)	(1,261,209.39)	(1,100,467.02)
	2004						
3	7.35% Capital Preferred Trust series due 4/1/2014	100,000,000	(5,960,820.11)	(715,557.34)	(1,982.15)	-	-
4	7.35% Preferred Trust series due 9/1/2014	100,000,000	(7,172,482.87)	(997,154.21)	(294,658.09)	-	-
5	6.36% Medium Term Note due 4/1/2014	17,000,000	220,776.78	22,107.44	61.24	-	-
6	6.40% Medium Term Note Due 4/1/2014	33,000,000	447,541.86	44,816.05	124.14	-	-
	2005						
7	6.10% Medium Term Note Due 7/15/2021	28,500,000	1,652,569.08	880,071.32	773,932.06	667,792.80	552,808.61
	2008						
8	Var% SR 2005A BCIDA due 7/15/21	28,500,000	(306,749.60)	(193,100.44)	(169,811.94)	(146,523.44)	(121,294.24)
	2011						
9	5.95% FMB due 5/15/2027	13,690,000	601,610.32	529,645.97	492,148.91	454,651.85	414,030.04
	TOTAL		(2,547,983.37)	(1,115,455.08)	(735,805.13)	(645,677.11)	

METROPOLITAN EDISON COMPANY

"Filing of information and materials – Whenever a public utility proposes a change in rates under section 1308 (relating to voluntary changes in rates), the public utility shall file with the commission a listing of each type of advertising prepared, distributed or presented by the pubic utility or to be prepared, distributed or presented during the test year utilized by the public utility in discharging its burden of proof, and a listing of each type of advertising prepared, distributed or presented by the utility during the year immediately preceding the test year, as well as an accounting of the expenditures by the public utility for such advertising, to the extent such advertising is proposed to be included as operating expense for ratemaking purposes. The filing requirements imposed by this subsection shall not be construed to limit the right of any party to discovery under this or any other provision of law."

Summary of Advertising Expenses

Section 1316 of Title 66, Pa. Consolidated Statutes, addresses recovery of advertising expenses. In accordance with the filing requirements specified in § 1316(c), following is a listing of the types of advertising comprising the total advertising expenses for the fully future test year and the immediately preceding 2 years.

Metropolitan Edison Company
Summary of Advertising Expenses
(000's)

Line No.	Description	12 months ending April 30. 2016 Budgeted	March 31. 2015 Budgeted	March 31. 2014 Actual
			(In thousands)	
1	Customer Service Informational & Instructional Advertising	$ 130	$ 58	$ 1
2	Sales Advertising	25	26	15
3	A&G Advertising - General	10	10	5
4	Public relations	-	-	75
5	Miscellaneous	-	-	2
6	Total advertising	$ 165	$ 94	$ 98

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT TITLE 52, SECTION 69.36

"The Pennsylvania Public Utility Commission intends to examine specific factors in rate proceedings of electric and gas utilities regarding the action or failure to act to encourage development of cost effective energy supply alternatives. Specifically, the Commission will review utilities' efforts to meet the criteria in this section when determining just and reasonable rates in future rate proceedings and may consider those efforts in other proceedings instituted by the Commission

(1) *Information.* At least twice annually utilities should provide customers with information on specific means of utilizing their energy services more effectively and efficiently. Topic areas should include insulation, lighting efficiencies, appliance efficiencies, conservation practices, load management techniques or other relevant information that informs the customer of the efficient use of energy.

(2) *Energy surveys.* Class A utilities should offer onsite energy surveys to the residential, commercial and industrial classes on an ongoing basis. Surveys should be conducted by trained personnel and the results of the survey, upon written request of the customer, be delivered in writing with a clear explanation of the resulting components.

(3) *Cogeneration and small power production.* Electric utilities for which a need for capacity is projected should establish effective programs to explore and encourage the development of additional cogeneration and small power production facilities within their respective service territories.

(4) *Least cost planning.* Gas and electric utilities should actively pursue a least-cost strategy by acquiring and developing the resources necessary to effectively meet their customers' future energy needs, consistent with established availability and reliability criteria. Utilities should make a reasonable effort to promote the utilization of practical and economical energy conservation and demand management through cost effective programs.

(5) *Evaluation.* Class A utilities should demonstrate progressive work regarding development of a reliable customer data base, including, but not limited to:

(i) End-use applications for each class of customer in terms of energy and demand.
(ii) Customer behavior with regard to the decision-making process.

(iii) The impact of program decisions or strategies and how they effect the overall planning process.

6) *Natural gas co-firing.* Electric utilities should explore the potential for increasing capacity and output at coal-fired generating stations through gas co-firing"

RESPONSE:

1) Customer service representatives discuss these "Energy Efficient" topics with customers by referring to the "Energy Decision Maker Brochure" which provides energy saving information for most household electrical appliances and equipment. Representatives offer to mail a copy of the brochure to customers and if appropriate, discuss the Time of Day Rate. The Company's interactive voice response unit also provides this brochure through the "Literature Request" option. These "Energy Efficient" topics are also fully described and available 24/7 on the FirstEnergy website under the "Customer Care" section at the following location:

http://www.firstenergycorp.com/customercare/engine?s=com.firstenergycorp.customercare.www.Home&p=%2F

In addition, on October 15, 2008, Governor Rendell signed HB 2200 into law as Act 129 of 2008[1], with an effective date of November 14, 2008. The Act imposes requirements on electric distribution companies (EDCs), with the overall goal of reducing energy consumption and demand. Act 129 directed all EDCs with at least 100,000 customers to develop and file an energy efficiency and conservation plan. The Company has filed and obtained approval for an Energy Efficiency and Conservation (EE&C) Plan that complies with Commission Orders[2]. The EE&C plan contains numerous programs that are designed to achieve energy efficiency and conservation across all customer segments. Essential to the success of these programs is a concurrent marketing and educational campaign. As part of this, the Company has an outreach effort that: (i) builds awareness and interest in the programs; (ii) communicates ways that customers may participate; and (iii) explains expected benefits and reasons for participating. Information about the EE&C programs available to customers is provided using a number of marketing channels such as via bill inserts, advertisements as well as through the Company's website at:

http://www.firstenergycorp.com/save_energy/save_energy_pennsylvania.html

2) Residential home energy surveys are conducted at no additional cost for income-eligible customers as part of the Low Income Usage Reduction Program known as

[1] 66 Pa.C.S. §§ 2806.1 and 2806.2
[2] Docket Nos. M-2009-2092222 and M-2012-2334387

WARM (Chapter 58). Met-Ed income eligible customers who have lived at their residence at least 6 months are eligible for WARM. The WARM program home energy survey addresses ways to save electricity for customers who have electric heat, electric water hear, air conditioning or base load use. These surveys are conducted by Building Performance Institute Certified contractors hired by Met-Ed. The program is open to both homeowners and renters with landlord agreement. As part of the home energy survey, contractors may perform pressure diagnostic testing using a blower door and manometers to determine where there is air leakage in the home. They also test ducts, conduct combustion safety testing and monitor electricity use of various appliances such as refrigerators and freezers for possible replacement. A personalized partnership agreement and energy-saving strategy for the home and occupants are provided as part of the program.

In addition, residential customers may also participate in the Company's Act 129 energy audit program. Under this program, home energy audits are conducted by trained local contractors hired by the Company's Conservation Service Provider for a fee of $350. Customers who participate in this program receive a comprehensive home energy audit which is designed to provide information on how to reduce their energy usage and increase their home's comfort and energy efficiency. Participating customer's qualify for up to $250 in rebates towards the cost of a comprehensive residential energy audit and qualified retrofits.

Residential customers can also complete the Company's Home Energy Analyzer online tool at http://www.firstenergycorp.com/content/customer/save_energy/save_energy_pennsylvania/for_your_home/pa_home_energy_analyzer.html to save energy and money. The tool enables customers to gain a better understanding of their household energy use and identify ways to improve their efficiency.

The Company also promotes detailed energy audits for commercial and industrial customers under the Company's Act 129 programs. Customers who implement recommended building and/or system improvements are eligible for incentives towards the cost of the third party audit and qualifying audit recommended improvements.

Similar to residential customers, business customers can complete the Business Energy Analyzers online tool at https://www.firstenergycorp.com/content/customer/save_energy/save_energy_pennsylvania/for_your_business/pennsylvania_businessenergyanalyzer.html. The tool will enable business customers to gain a better understanding of their energy use and identify ways to improve their efficiency.

3) Met-Ed's Rider H- Renewable Energy Development Rider is currently available to residential and non-residential customers. This rider encourages the installation and

operation of qualifying renewable energy generation projects to operate in parallel with the Company's electrical system.

4) All capacity requirements are secured through Commission approved default service plans.

5) See the direct testimony of Kevin M. Siedt, Met-Ed Statement No. 4.

6) This filing requirement is not applicable to the Company's filing.

METROPOLITAN EDISON COMPANY
Distribution Storm Costs
2009 – 4/30/2016

Line No.	Year	Storm Costs
1	2009	$ 7,075,372
2	2010	12,760,136
3	2011	34,827,259
4	2012	32,594,558
5	2013	1,208,183
6	12 mos. Ended March 31, 2014	14,921,313
7	12 mos. Ended March 31, 2015	6,564,065
8	12 mos. Ended April 30, 2016	6,625,214

Met-Ed/Penelec/Penn Power/West Penn
Costs of Compliance with Docket No. L-2014-2409383

This exhibit contains the expenditures and operations and maintenance ("O&M") costs associated with implementation of the Commission's three day switching requirement introduced at Docket No. L-2014-2409383 entered April 3, 2014. The exhibit contain incremental O&M expenses plus a five year amortization of additional capital expenditures to implement 3-5 day switches.

Phase I is an eight month project commencing May 1, 2014 with anticipated implementation by the end of December 2014. Phase I will enable the Companies to allow for one customer switch to be accomplished per individual customer account that has no other pending orders. The first phase of the project is a capital effort requiring the labor of 12 full time equivalent ("FTE"), working during Phase I development. Phase I development costs are expected to be $1,382,000.

Phase II is the on-going effort to modify the existing systems in order to implement multiple customer switches per month and ensure customers on payment programs can be accommodated. Phase II development would commence after Phase I is completed with anticipated implementation by the end of June 2015. The Phase II development costs are expected to be $850,000.

In addition, the Companies would need to add to existing staff 6 FTE's in Customer Service and Information Technology plus the cost of mailing letters to customers of multiple switches of $455,000 plus $227,500 for labor related overheads for a total of $682,500 on ongoing O&M costs.

Line No.	Description	Amount
1.	Phase I Capital Costs	$1,382,000
2.	Phase II Capital Costs	850,000
3.	Total	$2,232,000
4.	Five Year Recovery	$ 446,400
5.	On-going O&M expenses	682,500
6.	Total to be recovered annually	$1,128,900

Met-Ed/Penelec/Penn Power/West Penn
Costs of Compliance with Docket No. L-2014-2409383

Allocation to Pennsylvania operating companies based on number of customers:

		Amount ($000)
7.	Met-Ed	$ 311
8.	Penelec	326
9.	Penn Power	90
10.	West Penn	402
11.	Total	$ 1,128

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2014-2428745

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. R-2014-2428743

PENNSYLVANIA POWER COMPANY
DOCKET NO. R-2014-2428744

WEST PENN POWER COMPANY
DOCKET NO. R-2014-2428742

Direct Testimony
of
Charles V. Fullem

List of Topics Addressed

Overview of Distribution Base Rate Case Filing
Initiatives to Manage Costs, Enhance Customer Service and Assure Reliable Service
Reasons for the Requested Increases
Organization of the Filing and Introduction of Witnesses
Importance of Adequate Rate Relief to the Companies

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DIRECT TESTIMONY
OF
CHARLES V. FULLEM

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Charles V. Fullem, and my business address is 2800 Pottsville Pike, Reading, Pennsylvania 19612.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company, which is a direct subsidiary of FirstEnergy Corp. ("FirstEnergy"). I am the Director, Rates and Regulatory Affairs – Pennsylvania. The Pennsylvania Rate Department of FirstEnergy Service Company provides regulatory support for each of FirstEnergy's wholly-owned Pennsylvania operating companies: Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power") and West Penn Power Company ("West Penn") (collectively, the "Companies").

I am responsible to the Vice President of Rates and Regulatory Affairs for the development, coordination, preparation and presentation of the Companies' rate-related matters before the Pennsylvania Public Utility Commission ("Commission") and the New York Public Service Commission, including the default service programs. My responsibilities encompass the preparation of various statements and reports addressing, among other things, distribution revenue requirement, energy costs, non-utility generation costs, quarterly earnings, and other financial matters. I am also responsible for

administering the Companies' tariffs, including developing retail electric rates, rules and regulations and ensuring their uniform application and interpretation.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Mineral Economics from the Pennsylvania State University in November 1981. I have over thirty years of experience with FirstEnergy and its predecessor companies. My work experience is more fully described in my professional biography, which is attached as Appendix A.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Met-Ed, Penelec, Penn Power and West Penn.

Q. Please describe the purpose of your testimony.

A. The purpose of my testimony is to provide an overview of the distribution base rate increase requests that the Companies are proposing for approval by the Commission. I will explain why the proposed distribution rate increases will provide a fair return to shareholders and benefit customers by establishing the groundwork for enhanced reliability and customer service.

In addition to the Introduction, my testimony is divided into four subsequent substantive sections: Section II provides an overview of the Companies' requested rate increases. In Section III, I discuss the Companies' initiatives to manage costs and enhance customer service and reliability. In Section IV, I set forth the primary reasons the Companies are requesting increases in rates. In Section V, I describe the organization of the Companies'

rate filings, introduce the Companies' witnesses submitting direct testimony, and explain the importance of this case to the Companies and their customers.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibits CVF-1 through CVF-4 for each of the Companies, which consist of the following:[1]

Exhibit CVF-1 provides a summary of the rate request and specific reasons for each rate increase. This exhibit also identifies and quantifies the major components of each Company's proposed revenue increase.

Exhibit CVF-2 identifies the witnesses submitting direct testimony, their corresponding statement numbers and their areas of responsibility.

Exhibit CVF-3 is a table showing, at present and proposed rates, each Company's revenues, operating expenses, operating income and rate base, as adjusted for ratemaking purposes, and the resulting overall rates of return for the fully projected future test year ("FPFTY"), the twelve months ended April 30, 2016. The table also provides references to exhibits sponsored by other witnesses that set forth this information in more detail.

Exhibit CVF-4 provides a corporate history, including the dates of each Company's original incorporation and subsequent mergers and acquisitions.

[1] Exhibits CVF-1 through CVF-4 respond to filing requirements outlined in 52 Pa. Code § 53.53(a)(3). Specifically, these exhibits respond to requirements I-A-1, 2 and 3 and I-B-1 of Exhibit C to Section 53.53.

I am also sponsoring Met-Ed/Penelec/Penn Power/West Penn Exhibit CVF-5, which depicts a comparison of residential customer bills at the Companies' existing and proposed base rates to residential customer bills, at the same usage levels, of Duquesne Light Company, PECO Energy Company and PPL Electric Utilities Corporation.

II. OVERVIEW OF THE REQUESTED DISTRIBUTION RATE INCREASES

Q. Please explain when the Companies' base rates were last increased.

A. The current distribution base rates of Met-Ed and Penelec were established pursuant to the Commission's Final Order entered January 11, 2007 at Docket Nos. R-00061366 and R-00061367, which were the last base rate proceedings for those Companies. Notably, that proceeding resulted in a **decrease** in Met-Ed's and Penelec's distribution base rates. Consequently, Penelec's base rates have not increased since 1986 and Met-Ed's base rates have not increased since 1992, when their fully bundled base rates were last increased.

Penn Power's current distribution base rates were established pursuant to the Commmission's Final Order issued July 22, 1998 in the proceeding at Docket No. R-00974149, in which Penn Power's bundled rates for electric service were functionally unbundled. Prior to unbundling, Penn Power's fully bundled rates had been established in a general base rate increase proceeding at Docket No. R-870732, which concluded with a Final Order entered on May 3, 1988.

West Penn's current distribution base rates were established when West Penn's base rates were functionally unbundled pursuant to the Commission's Final Order entered November 19, 1998 at Docket No. R-00973981. Prior to that case, West Penn had last

increased its base rates pursuant to the Commission's Final Order entered December 29, 1994 in a general base rate proceeding at Docket No. R-00942986.

As the summary above shows, the distribution base rate increases proposed by the Companies would be, when they become effective, their first general base rate increases in over twenty-one to twenty-nine years, depending on the Company.

Q. Please describe the increases and changes in rates for distribution service that the Companies are proposing.

A. The Companies are proposing increases in their distribution base rates that constitute general rate increases under Section 1308(d) of the Public Utility Code. In addition, the Companies are proposing to adopt new riders and to change several existing riders that set forth reconcilable adjustment clauses established or proposed to be established under Section 1307 of the Public Utility Code. Certain of these riders and changes in existing riders affect distribution base rate revenue.

Q. Please identify the principal new riders and principal changes in existing riders that affect distribution base rate revenue in this case.

A. West Penn is proposing to adopt a Universal Service Cost ("USC") Rider to recover the cost of its Universal Service programs. West Penn's proposed USC Rider mirrors the USC Riders that the Commission approved for Met-Ed and Penelec in their last distribution base rate cases. The Commission approved a similar USC Rider for Penn Power in its order entered April 11, 2008 at Docket Number R-00072437. West Penn's proposed USC Rider is discussed in more detail in the direct testimony of Kimberlie L. Bortz (Met-Ed/Penelec/Penn Power/West Penn Statement No. 3). As Ms. Bortz explains,

the USC Rider is needed to help West Penn continue to meet the needs of its low-income customers.

West Penn is also proposing a revision to its Default Service Support ("DSS") Rider and its Hourly Pricing Default Service ("HPS") Rider. As explained by Laura W. Gifford in Met-Ed/Penelec/Penn Power/West Penn Statement No. 7, the DSS Rider and HPS Rider, as revised, will include components to recover default service-related uncollectible accounts expense for residential and commercial customers and industrial customers, respectively. These changes are being made to unbundle default service-related uncollectible accounts expense by removing that expense from West Penn's distribution base rate revenue requirement and recovering it through West Penn's DSS and HSP Riders. As Ms. Gifford also explains, Met-Ed, Penelec and Penn Power, all three of which previously unbundled their default service-related uncollectible accounts expenses, are proposing revisions to their DSS and HPS Riders so that default service-related uncollectible accounts expense for industrial customers will be recovered in their HPS Riders rather than as they are currently being recovered through their DSS Riders.

Each of the Companies currently has a Smart Meter Technologies Charge ("SMT-C") Rider that sets forth a Commission-approved adjustment clause imposing a SMT-C to recover the costs of implementing their Smart Meter Deployment Plan ("Smart Meter Plan"). The Companies are proposing to include in their distribution base rate revenue requirements their test period costs to implement their Smart Meter Plans, to recover those costs in their distribution base rates, and to reduce their SMT-C Rider rates to zero. The SMT-C Rider will remain in the Companies' tariffs as the mechanism to recover the

costs of implementing their Smart Meter Plan, net of savings, in excess of such costs being recovered in base rates in the future.

Q. Are the Companies proposing to adopt any additional riders or revise any existing rider?

A. Yes, they are. Each of the Companies is proposing to adopt: (1) a Storm Damage Charge Rider, to recover the cost of storm damage in excess of that recovered in base rates; (2) a Partial Service Rider, to recover the cost of back-up and auxiliary services furnished to customers operating behind-the-meter generation that does not qualify for net metering; and (3) a Cogeneration and Small Power Production Qualifying Facility Rider, which will provide the terms on which each of the Companies will purchase electricity generated by "qualifying facilities" with maximum generating capacity under 500 kW. The Storm Damage Charge Rider is described in more detail in Ms. Bortz's direct testimony. The Partial Service Rider and Cogeneration and Small Power Production Qualifying Facility Rider are described in more detail in the direct testimony of Kevin M. Siedt (Met-Ed/Penelec/Penn Power/West Penn Statement No. 4).

In addition, Met-Ed and Penelec are each proposing to adopt a Time-of-Use Default Service Rider as an option available to all residential customers that obtain default service from the Company. The proposed Time-of-Use Default Service Rider is similar to the Time-of Use-Default Rider and Time-of-Use Rider approved by the Commission for Penn Power and West Penn, respectively, in the Commission's Final Order at Docket Nos. P-2011-2273650, et al., which approved the Companies' default service programs

for the period June 1, 2013 through May 31, 2015. West Penn's Time-of-Use Default Service Rider is described in more detail in Mr. Seidt's direct testimony.

Finally, as explained by Ms. Bortz, Penn Power is proposing to revise its existing USC Rider simply to make its terms uniform with those of the existing, Commission-approved USC Riders of Met-Ed and Penelec.

Q. Please summarize the effect that the proposed increases and changes in distribution rates and riders will have on the Companies' pro forma revenues at current rates for the FPFTY.

A. The effect of the proposed increases and changes in distribution rates and riders on the Companies' pro forma revenues at current rates for the FPFTY is provided in the table below:

	Requested Revenue Change			
	Met-Ed	**Penelec**	**Penn Power**	**West Penn**
	($ Thousands)	**($ Thousands)**	**($ Thousands)**	**($ Thousands)**
Distribution Base Rates	149,328	116,499	25,379	66,825
USC Rider				29,565
DSS and HPS Riders	(716)	(524)	(1,074)	7,351
Smart Meter	3,315	3,817	4,178	11,794
Total Revenue Increase	151,927	119,792	28,483	115,535
Percentage Change Over Revenues At Existing Rates[1]	11.5%	8.6%	8.7%	8.4%

[1] The percentage was calculated based on total estimated revenue for the fully projected future test year consisting of distribution revenue as well as generation service revenue, with the latter reflecting generation rates equivalent to the Companies' prices for applicable default service.

Q. What are the overall rates of return and the rate of return on common equity that the Companies propose as the basis for calculating each of their revenue requirements in this case?

A. The Companies' proposed distribution rates are designed to recover the Companies' costs to provide distribution service and provide them the opportunity to earn fair returns on their investments in distribution assets. As explained in more detail in the direct testimony of Michael J. Vilbert, Ph.D. (Met-Ed/Penelec/Penn Power/West Penn Statement No. 9) and Steven R. Staub (Met-Ed/Penelec/Penn Power/West Penn Statement No. 10), the increases in distribution base rate revenues proposed by the Companies would provide each of them an opportunity to earn a 10.90% return on equity. The overall rates of return requested for each of the Companies are as follows:

Met-Ed	8.05%
Penelec	8.31%
Penn Power	8.51%
West Penn	8.14%

Q. You indicated earlier that the Companies are proposing certain new riders and revisions to existing riders. Will those new or revised riders, if approved, increase the Companies' rates of return?

A. No, they will not. The costs proposed to be recovered under the new or revised riders are not included in the Companies' distribution base rate revenue requirements. Those costs, which are clearly identifiable, volatile, and not within the Companies' control, would be recovered under the proposed riders on a dollar-for-dollar basis, neither more nor less. Because the riders would only recover actual costs, they will not augment the rates of

return forming the basis for the Companies' proposed distribution base rates in this case. For those reasons and because the proposed new and revised riders reflect adjustment clauses that, either in form or concept, have been previously approved by the Commission, the Companies' new and revised riders should be approved.

Q. How will the proposed distribution rate increases impact the total bill of a typical residential customer using 1,000 kWh per month for each Company and how do the Companies' bills to residential customers at proposed rates compare to existing bills of other Pennsylvania electric distribution companies ("EDCs")?

A. The table below shows for each Company: (1) a September 2014 monthly bill for a residential default service customer using 1,000 kWh; (2) the increase for September that would result from the proposed base rates; and (3) the new total September bill under proposed base rates.

	September Bill	**Increase**	**Total Bill After Increase**
Met-Ed	$116.56	$20.78	$137.34
Penelec	$120.46	$19.58	$140.04
Penn Power	$104.76	$12. 39	$117.15
West Penn	$92.47	$13.62	$106.09

Using rates in effect as of July 19, 2014 for the other three major Pennsylvania EDCs (those companies' September 2014 default service rates were not publicly available when the comparison was prepared), a residential customer using 1,000 kWh per month would pay a monthly bill of between $137.05 and $153.19. Thus, even at the Companies' proposed base rates, residential customers receiving default service from the Companies would pay either approximately the same or considerably less than customers of the other

three major Pennsylvania EDCs at a similar usage level. Page 1 of Met-Ed/Penelec/Penn Power/West Penn Exhibit CVF-5 graphically depicts the billing comparison I just described. Page 2 of the exhibit graphically depicts the same comparison of monthly bills, excluding generation and transmission-related costs. Based on that comparison, West Penn, Penn Power and Met-Ed, at their existing distribution base rates, are the three lowest-priced electric utilities in Pennsylvania. At the proposed distribution base rates, the average of the bills of residential customers of the Companies using 1,000 kWh is approximately equal to the average of the bills of residential customers with comparable usage of the other three major Pennsylvania EDCs at their existing distribution rates.

III. INITIATIVES TO MANAGE COSTS, ENHANCE CUSTOMER SERVICE AND MAINTAIN RELIABLE ELECTRIC SERVICE

Q. Please describe the principal initiatives the Companies have implemented to control operating and maintenance ("O&M") expenses.

A. The Companies have implemented various initiatives that have allowed them to control O&M expenditures and, in particular, administrative and general ("A&G") costs, since their base rates were last increased. Some of the initiatives that have had the most significant impacts are the following:

1. **Capturing economies of scale and maximizing merger-related synergies**. FirstEnergy, the parent of the Companies, was formed on November 7, 1997, when Ohio Edison Company ("Ohio Edison") acquired Centerior Energy Corporation ("Centerior"). That merger formed a single holding company structure that included Centerior's operating utilities (The Cleveland Electric Illuminating Company ("CEI") and The Toledo Edison Company ("Toledo

Edison")) and Ohio Edison, which was itself an operating utility, and its Pennsylvania subsidiary, Penn Power. In 2001, GPU, Inc. ("GPU") merged with FirstEnergy, which added Met-Ed, Penelec and Jersey Central Power & Light Company ("JCP&L") to FirstEnergy's family of operating electric utilities. In 2011, Allegheny Energy, Inc. ("Allegheny Energy") merged with FirstEnergy, which added to the holding company system Allegheny Energy's operating subsidiaries, consisting of Monongahela Power Company, Potomac Edison Company and West Penn.

FirstEnergy Service Company was established in its current form to capture economies of scale by providing various services on a shared basis across all of FirstEnergy's subsidiaries. In addition, FirstEnergy has implemented standardized programs and business processes that adopt the best practices identified among its various operating subsidiaries. These practices have maximized the savings achievable by eliminating duplication and from capturing economies of scale, which were made possible by the mergers that formed the current FirstEnergy utility holding company system.

2. **Aggressive management of indirect labor-related costs.** Most of the Other Post-Employment Benefits ("OPEBs") formerly provided to FirstEnergy Service Company employees and utility supervisory, management, and non-bargaining unit employees have been eliminated. This measure and other measures to aggressively manage employee benefit costs while maintaining a competitive compensation package have helped the Companies contain their labor-related costs. Consequently, the Companies are only claiming the service cost

component associated with OPEBs, which represents the actuarial present value of the benefit liabilities accrued under the plan benefit formula, for services rendered during the FPFTY in this proceeding.

3. **A sharper, renewed focus on maintaining and enhancing reliability.** The Companies' sharper, renewed focus on reliability has resulted in higher levels of capital expenditures for distribution system enhancements. In addition to enhancing reliability and, thereby, directly reducing maintenance expenses, a secondary consequence of this renewed focus on reliability-related capital improvements has been to increase the percentage of total costs that are capitalized rather than charged to O&M expense.

Q. Please describe the Companies' initiatives to improve customer service and maintain or improve reliability and their significant accomplishments in those areas.

A. The Companies have implemented many more customer service and reliability-related enhancements than I can reasonably identify and describe in my testimony. Consequently, I will focus on major initiatives and accomplishments since 2006, which is a reasonable starting point because it was the last time Met-Ed and Penelec filed a base rate case and because it predates the FirstEnergy/Allegheny merger. Those major initiatives and accomplishments consist of the following:

1. **Integration of three call centers.** Between the completion of the FirstEnergy/GPU merger and 2007, two call centers were operating independently to serve the customers of FirstEnergy's utility subsidiaries. One call center served

CEI, Ohio Edison, Penn Power and Toledo Edison customers, and another served Met-Ed, Penelec, and JCP&L customers . In 2007, after careful review and detailed planning, FirstEnergy integrated the technology and operations of the two call centers, enabling the following steps to create efficiencies and enhance performance:

i. The call centers initiated "virtualization" of certain types of location-specific calls, which enabled those calls to be routed to an available agent in any call center regardless of where the call originated. This change increased, from approximately 200 to approximately 400, the number of agents that could take outage, move-in and move-out calls at a given time.

ii. The utilization of agents was increased by routing to the next available agent whatever caller had been waiting the longest, regardless of the caller's location.

iii. By integrating the call centers, calls could be routed from one center to another as necessary to reduce "busy outs" and increase business continuity/disaster recovery capabilities. A busy out occurs when a customer calling the Company gets a busy signal as the capacity of the call center has been reached or exceeded.

iv. The call centers adopted the same technology for monitoring and reporting performance to ensure that call volumes, call types, service levels, agent performance, busy outs, and other metrics were calculated uniformly and could be meaningfully compared and assessed.

v. Call flows were standardized in order to decrease average handle time and improve the quality of customers' experience.

As I previously noted, in 2011, Allegheny Energy merged with FirstEnergy, which added the call center serving West Penn and Allegheny Energy's other utility subsidiaries. In 2012, FirstEnergy integrated the technology and operations of the former Allegheny Energy call center with its two other call centers, which achieved the following additional efficiencies and service enhancements:

i. Further "virtualization" was achieved for outage, move-in, move-out, and credit calls, which had the effect of increasing, from approximately 130 to 800, the number of agents available to take those types of calls for West Penn and the other former Allegheny Energy utility subsidiaries at a given time.

ii. Call center resources were maximized and optimized by creating the capability to route calls to agents in any one of three call centers, which further reduced the likelihood of busy outs and provided even better business continuity/disaster and recovery capabilities.

iii. The process of integration provided the former Allegheny Energy call center the capability, which it did not previously have, to monitor and report performance metrics at the operating company level. Previously, Allegheny Energy's utility subsidiaries could compile and report data and metrics based only on their combined performance levels.

iv. FirstEnergy implemented "virtual hold" at the former Allegheny Energy call center. Virtual hold is a technology that allows customers to choose to receive a callback rather than waiting on line to speak to an agent.

By integrating the technology and operations of multiple call centers, Met-Ed, Penelec, and Penn Power have been able to answer 80% of all the calls they received within 30 seconds in three of the last four years. West Penn is on track to achieve the goal of answering 70% of all the calls its receives within 30 seconds by 2015, which is a commitment it made in the Joint Petition for Partial Settlement approved by the Commission as part of the proceeding which granted approval of the FirstEnergy/Allegheny Energy merger. Additionally, West Penn's average speed of answer has decreased from 145 seconds in 2011 to 104 seconds for the first six months of 2014.

2. **Enhanced communication during major storms.** The Companies have materially enhanced communication with customers, local governments, emergency service providers and first responders during major storm events by adopting and effectively using social media and internet-based access to storm and restoration-related information. For the second year in a row, FirstEnergy's mobile-optimized website and Smart Phone "app" have been recognized among the top performers in a customer satisfaction survey conducted by J.D. Power. Specifically, in J.D. Power's 2014 Utility Website Evaluation Study, FirstEnergy received the third highest score for overall customer satisfaction when its utility subsidiaries' websites were viewed from a mobile device (FirstEnergy's mobile website and SmartPhone app for Apple® iPhone® and Android™ devices

received a score of 425 out of 500 points). FirstEnergy also was among the top three performers for mobile websites in J.D. Power's 2013 study. In 2013, the number of customers visiting the FirstEnergy website(s) via a Smart Phone or tablet tripled over the previous year, which is why the Companies are continuing to make it easier to manage electric accounts and report power outages using mobile tools.

3. **Recognition for customer service.** The Companies, as part of the FirstEnergy family of utilities, were recognized by the Edison Electric Institute's National Key Accounts Customer Advisory Group for providing outstanding customer service in 2014. This is the second time FirstEnergy received honors in this category, having won similar recognition in 2006. In addition, Met-Ed, Penelec and Penn Power have on average seen a five percent increase in overall customer satisfaction between 2010 and 2014 as measured by the J.D. Power 2014 Electric Utility Residential Customer Satisfaction Study released July 16, 2014 when compared to the same study in 2010 (West Penn did not have a rating in the J.D. Power survey in 2010). All of the Companies earned scores that were above their segment average in the J.D. Power 2014 Electric Utility Residential Customer Satisfaction Study, and Penn Power ranked second in overall satisfaction in the East Region: Midsize Segment Customer Satisfaction Index in that same survey of customer satisfaction by J.D. Power.

4. **Customer referral programs.** The Companies have successfully implemented customer referral programs that, since their implementation in August 2013, have enrolled over 100,000 residential and small commercial customers with

competitive retail suppliers. The Companies developed their customer referral programs in response to the Commission's recommendations in its Order entered on April 29, 2011 in the *Investigation of Pennsylvania's Retail Electricity Market* at Docket No. I-2011-2237952. The Companies' customer referral programs were adopted, with Commission approval, in conjunction with their default service plans for the period from June 1, 2013 through May 31, 2015.[2]

5. **Portable Customer Assistance Program ("CAP") benefits.** The Companies have offered fully portable CAP benefits since generation rate caps have expired, which has enabled their low income customers to access competitive retail electric markets while preserving their ability to take full advantage of the benefits available under the Companies' Universal Service programs, regardless of their shopping status.

6. **Maintaining reliable electric service**. Each of the Companies has made system enhancements and implemented specific initiatives designed to enhance reliability and provide customers high-quality, dependable service. The table below reflects each Company's performance measured by System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") and shows how the Companies' performance compares to the Commission's benchmark and to the twelve-month standard for each of those reliability indices:

[2] *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs*, Docket Nos. P-2011-2273650, P-2011-2273668, P-2011-2273669 and P-2011-2273670 (Final Order entered August 16, 2012).

Company	12 month rolling	Benchmark	12-Month Standard	Pennsylvania 2009	2010	2011	2012	2013
	SAIDI	135	194	134	181	142	155	115
	SAIFI	1.15	1.38	1.21	1.51	1.21	1.29	1.09
	CAIDI	117	140	111	120	117	120	105
	SAIDI	113	162	87	95	143	133	188
	SAIFI	1.12	1.34	0.75	1.01	1.03	1.17	1.35
	CAIDI	101	121	116	95	138	114	140
	SAIDI	148	213	143	162	233	194	174
	SAIFI	1.26	1.52	1.22	1.31	1.40	1.41	1.48
	CAIDI	117	141	117	124	167	138	117
	SAIDI	179	257	161	191	211	241	222
	SAIFI	1.05	1.26	0.97	1.00	1.40	1.07	1.21
	CAIDI	170	204	166	190	151	226	183

32%	19	Exceed Benchmark
62%	37	Between Benchmark and Standard
7%	4	Below Standard

Over the last five years, the Companies' reliability metrics have been better than the Commission's 12-month standard in 94% of the comparisons and better than the Commission's Benchmark in 32% of the comparisons.

Further, the table below shows a total capital outlay by the Companies to enhance or maintain reliability between 2009 and 2013 of nearly $ 1.9 billion.

	T&D Capital - Reported under Section 57.195(b)(8)						
			Dollars in Millions				
	2009	2010	2011	2012	2013		5-Year Total
Penn Power	$ 21.10	$ 24.90	$ 24.90	$ 31.60	$ 24.80		$ 127.30
Penelec	$ 124.30	$ 126.40	$ 126.60	$ 156.00	$ 140.10		$ 673.40
Met-Ed	$ 95.80	$ 101.50	$ 107.50	$ 156.50	$ 90.20		$ 551.50
West Penn	$ 71.70	$ 86.90	$ 128.20	$ 149.30	$ 102.80		$ 538.90
Total	$ 312.90	$ 339.70	$ 387.20	$ 493.40	$ 357.90		$ 1,891.10

7. **Smart Meter Implementation.** Under their Smart Meter Plans, the Companies will be providing 95% of their customers with smart meters by mid-2019. To

implement those plans, the Companies will make capital expenditures totaling approximately $667 million for smart meters and advanced metering infrastructure ("AMI") designed to allow customers to better manage their energy usage.

IV. REASONS FOR REQUESTED RATE RELIEF

Q. What are the principal factors driving the Companies' needs to increase their distribution base rates?

A. There are four principal factors driving the Companies' needs to increase their distribution base rates, as follows:

1. **Growth in the Companies' distribution rate bases**. The single biggest factor driving the need for rate relief is the growth in the Companies' rate bases attributable to increases in net investment in distribution plant in service. This is shown in the table below which provides a comparison of net distribution plant in service as of April 30, 2016, derived from each Company's Exhibit RAD-1, to their net investments in distribution plant in service from a point in time that corresponds with their last base rate cases. For Met-Ed and Penelec, the historic point of comparison is the net investment in distribution plant in service established by the Commission's January 11, 2007 Order in their 2006 distribution base rate cases. For Penn Power and West Penn, the data source is each Company's FERC Form 1 for the year of their last change in base rates, as explained in footnote (a) to the table. The differences between the earlier timeframe and the period depicted in Exhibits RAD-1 provide a reasonable

indication of the additional investment the Companies have made in net distribution plant in service since their last base rate cases, which also confirms that growth in rate base is a significant driver of their requested distribution rate increases.

	MET-ED	PENELEC	PENN POWER		WEST PENN	
Year of Last Base Rate Case	2007	2007	1988		1994	
Net Plant in Service	1,007,085	1,155,461	87,447	(a)	635,246	(a)
Net Plant in Service at 4/30/2016 (From Exs. RAD-1)	1,514,554	1,766,868	420,106		1,408,494	
Growth in Net Plant	50.39%	52.91%	380.41%		121.72%	

(a) Penn Power's and West Penn's last rate cases occurred before restructuring of the electric industry in Pennsylvania, and the net plant in service reflected in their supporting data and the Commission's final orders in those cases included generation, transmission and distribution plant. Therefore, the net plant shown above for Penn Power and West Penn for 1988 and 1994, respectively, was obtained from each Company's FERC Form 1 for those years and reflects total distribution plant plus an allocable portion of general and intangible plant.

2. **Depreciation expense associated with increased investment in plant in service.** The increases in new distribution plant in service result in corresponding increases in depreciation expense.

3. **Increase in depreciation expense related to retirement of legacy meters**. Act 129 of 2008 added Section 2807(f) to the Pennsylvania Public Utility Code, requiring EDCs to adopt and implement smart meter and AMI technology for all customers. As I previously discussed, the Companies are implementing Commission-approved Smart Meter Plans under which they will replace 95% of all existing meters with smart meters by mid-2019, or approximately three years from the end of the FPFTY. Absent the Smart Meter mandate of Section 2807(f) and the adoption of the Companies' Smart Meter Plans, the Companies' existing "legacy" meters would have remained in service and continued to be depreciated

over the average remaining lives of between twenty-three and forty-eight years, as reflected in the Companies' existing distribution base rate revenue requirements. The Companies are proposing to recover their remaining investment in their legacy meters over five years, which produces a material increase in depreciation expense.

4. **Deferred Storm Damage Expense Recovery.** The Companies' service areas have experienced numerous severe storm events which caused extensive damage to their distribution systems and required the expenditure of significant storm damage recovery expenses. Because those storm damage expenses were extraordinary, non-recurring and material for some of the Companies, those Companies requested, and the Commission granted, approval to defer those expenses. Specifically, Met-Ed, Penelec and Penn Power deferred costs for distribution non-capital storm expenses that exceeded 125% of storm costs included in base rates between the period of February 25, 2011 through September 30, 2012 pursuant to the terms of the Joint Petition for Partial Settlement approved by the Commission as part of the FirstEnergy/Allegheny Energy merger proceeding. These deferrals included amounts associated with Hurricane Irene, the October 2011 snowstorm, and Tropical Storm Lee, among other events. In addition, orders were issued granting the requests to approve deferrals for certain storm costs incurred by Met-Ed associated with Winter Storm Nika (Docket No. P-2014-2412229) and Hurricane Sandy (Docket No. P-2013-2351260) and by West Penn Power associated with the February 5-16, 2010 winter storm (Docket No. P-2010-2216111). In this proceeding, the Companies

are proposing to recover the deferred expenses in their distribution revenue requirement by amortizing the deferrals over three years, as explained in more detail in the direct testimony of Richard A. D'Angelo (Met-Ed/Penelec/Penn Power/West Penn Statement No. 2).

Q. Are the factors you discussed above offset in part by reductions in any other components of the Companies' revenue requirement?

A. Yes. As I previously explained, the Companies have been carefully managing their O&M expenses and, in particular, their A&G expenses. In the case of Met-Ed and Penelec, for which comparisons can readily be made between the O&M expense claims in this case and their prior distribution base rate cases, O&M expenses excluding depreciation claimed for the FPFTY and smart meter costs are actually lower than the O&M expenses excluding depreciation those Companies incurred during the future test year in their 2006 base rate cases when, of course, they had no smart meter costs.

V. ORGANIZATION OF THE FILING, WITNESSES AND THE IMPORTANCE OF THIS CASE TO THE COMPANIES AND THEIR CUSTOMERS

Q. Please identify the other witnesses presenting direct testimony on behalf of the Companies and the principal subjects they address.

A. The Companies are submitting the direct testimony of ten witnesses including myself. The other witnesses submitting direct testimony and the principal subjects they address are as follows:

Richard A. D'Angelo	Statement No. 2	Development of the Companies' revenue requirements, including sponsoring and explaining the Companies' principal accounting exhibits.
Kimberlie L. Bortz	Statement No. 3	Proposed changes to tariff Rules And Regulations; proposed Storm Damage Charge Riders; proposed West Penn USC Rider.
Kevin M. Siedt	Statement No. 4	Development of normalized sales and revenues; development of the Companies' proposed rate design; description of proposed Time-Of-Use Default Service Riders, Partial Service Riders And Cogeneration and Small Power Production Qualifying Facility Riders.
Hillary E. Stewart	Statement No. 5	Development of the Companies' cost of service studies; separation studies; cost of service at existing rates.
Patricia M. Larkin	Statement No. 6	Development of the Companies' claims for cash working capital.
Laura W. Gifford	Statement No. 7	Unbundling of West Penn default service uncollectible accounts expense and associated revisions to West Penn's DSS and HPS Riders; updating Met-Ed's, Penelec's and Penn Power's DSS and HPS Riders to recover industrial default service-related uncollectible accounts expenses through the HPS Riders.
Christopher D. Ciccone	Statement No. 8	Proposed LED Street Lighting Rate Schedules.
Michael J. Vilbert, Ph.D.	Statement No. 9	Cost of common equity.
Steven R. Staub	Statement No. 10	Capitalization ratios; cost rates of long-term debt and common equity; overall cost of capital.

Q. Please explain the importance of the proposed rate increases to the Companies?

A. Due in large part to their substantial investment in utility plant, and notwithstanding their success in containing O&M expenses, the Companies' overall rates of return, at present rates, are projected to be 2.10% (Met-Ed), 3.98% (Penn Power), 4.01% (Penelec) and 4.78% (West Penn) for the FPFTY. More importantly, the indicated returns on common equity under present rates are anticipated to be 1.0% (Met-Ed) 2.56% (Penn Power), 2.38% (Penelec) and 4.18% (West Penn), which are inadequate by any reasonable standard. Returns at those levels are simply not sufficient to fully support the substantial amounts of additional investment the Companies will be required to make to maintain and enhance reliability, replace aging infrastructure, and fully implement their Smart Meter Plans while benefitting customers with continued safe, reliable and high-quality service. Accordingly, it is critically important that the Companies obtain the rate relief they are requesting in this case.

Q. Given the importance of this case to the financial health of the Companies and their ability to continue to invest in plant and equipment to maintain and enhance reliability and customer service, do you have a recommendation regarding the rate of return that should be approved for the Companies?

A. Yes, I do. It is important that the Commission adopt a rate of return at the top of the range of rates of return on common equity developed by Dr. Vilbert. In addition to providing the Companies the level of income they need to maintain and increase their level of investment in distribution infrastructure, a rate of return at the top of Dr. Vilbert's recommended range will properly recognize the Companies' efficiency, their focus on customer service, their dedication to maintaining and enhancing reliability, and

their support of Pennsylvania's competitive retail energy market, all of which are exhibited by the initiatives and accomplishments discussed in Section III of my testimony. Additionally, a top-of-range rate of return on equity would also properly recognize the quality of the Companies' management decisions and, in particular, their success in controlling O&M expenses, which has enabled the Companies to extend the period between base rate cases, to the benefit of their customers.

Q. Does this conclude your direct testimony?

A. Yes, it concludes my direct testimony at this time. However, I would like to reserve the right to supplement my direct testimony should it become necessary to do so

Biography
Charles V. Fullem
Director – Rates & Regulatory Affairs/Pennsylvania

Charles V. Fullem is Director- Rates & Regulatory Affairs/Pennsylvania, a position he was appointed to on January 22, 2006. In that capacity, he is responsible for developing the default service plans of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company, as well as all retail tariff filings and financial reports to the Pennsylvania Public Utility Commission ("PaPUC") and the New York State Public Service Commission. He has over 30 years of experience in the energy industry, with a background in rates and regulation, marketing, unregulated retail pricing and regulated tariffs, contract development and negotiations of both wholesale and retail electric service contracts.

From December 2000 through January 2006, he served in various positions, including Director of Energy Consulting Operations for The E Group, the energy consulting subsidiary of FirstEnergy Corporation ("FirstEnergy"). As Director, he managed technical staff teams and was responsible for delivering all aspects of The E Group's client services for an over one billion dollar client energy spend, including energy management, bill and rate analysis, development of energy procurement strategies, preparation of requests for proposal, evaluation of bids, contract development and implementation, open market analysis, and negotiations with suppliers and utilities and utility bill payment.

From November 1999 through December 2000, Mr. Fullem was Director, Pricing and Regulatory Affairs, in FirstEnergy's rate department, where he was responsible for tariff administration and pricing programs serving over 2.2 million customers in Ohio and Pennsylvania. In this capacity, Mr. Fullem developed and implemented the unbundled tariffs designed to implement Customer Choice in Ohio, coordinated the development of FirstEnergy's Supplier Tariff and Net Metering Rider, and participated in the Operational Support Plan (OSP) workgroups. The OSP workgroups were collaborative working groups charged with establishing the various rules and policies of retail choice in Ohio.

From December 1994 through November 1999, Mr. Fullem served in various roles in FirstEnergy's marketing department, including Director, Planning and Strategy, and Director of Centerior Energy's Competitive Analysis Department, where he developed and implemented successful marketing programs targeted to commercial and industrial customers and mass market customers in both competitive generation markets and traditional areas of competition between fully integrated electric utility providers.

From 1982 through December 1994, Mr. Fullem served in various roles in rates and regulation at Centerior Energy and Cleveland Electric Illuminating Company, including the roles of Director, Planning & Strategy, and Director of Rates & Contracts. In these roles, Mr. Fullem managed and performed cost of service studies, load research, customer requirements analyses, designed rates and tariffs, participated in the development of revenue requirements, and performed financial analyses.

Mr. Fullem holds his Bachelor of Science degree in Mineral Economics from the Pennsylvania State University. Mr. Fullem is a Certified Energy Procurement Professional by the Association of Energy Engineers. He has provided expert testimony before the Public Utilities Commission of Ohio ("PUCO"), the PaPUC, The New York State Public Service Commission and the Federal Energy Regulatory Commission ("FERC").

Mr. Fullem has prepared and presented testimony in the following rate-related cases:

PUCO Cases:

Case Nos.	***Case Name***
85-521-EL-COI	(In the Matter of the Investigation into the Perry Nuclear Power Station)
88-170-EL-AIR	(In the Matter of the Application of the Cleveland Electric Illuminating Company for Authority to Amend and to Increase Certain of its Filed Schedules Fixing Rates and Charges for Electric Service)
88-171-El-AIR	(In the Matter of the Application of the Toledo Edison Company for Authority to Amend and to Increase Certain of its Filed Schedules Fixing Rates and Charges for Electric Service)
91-1528-EL-CSS	(In the Matter of the Complaint of Toledo Premium Yogurt, Inc., dba Freshens Yogurt, Complainant, v. Toledo Edison Company, Respondent)
91-2308-EL-CSS	(Board of Education, Cleveland City Schools v. Cleveland Electric Illuminating Company)
92-504-EL-CSS	(Board of Education, Cleveland City Schools v. Cleveland Electric Illuminating Company)
95-02-EL-ABN	(In the Matter of the Application of the City of Clyde Requesting Removal of Certain Electric Distribution Facilities of the Toledo Edison Company from Within Clyde's Corporate Limits)
01-174-EL-CSS	(In the Matter of the Complaint of the City of Cleveland and WPS Energy Services, Inc., Complaints, v. The Cleveland Electric Illuminating Company and FirstEnergy Corp., Respondents)

PaPUC Cases:

Docket No.	***Case Name***
R – 850267	(Pennsylvania Public Utility Commission, et al. v. Pennsylvania Power Company)
R – 860378	(Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company)
87-1160	(Duquesne Light Company and Pennsylvania Power Company, Appellants v. David M. Barasch, etc., et al.)
P-00072305	(Petition of Pennsylvania Power Company for Approval of Interim Default Service Supply Plan)
P-2008-2066692	(Voluntary Prepayment Plan)
P-2009-2093053	(Metropolitan Edison Company Default Service Programs)
P-2009-2093054	(Pennsylvania Electric Company Default Service Programs)
I-2009-2099881	(Compliance of Commonwealth of Pennsylvania with Section 410(a) of the American Recovery and Reinvestment Act 2009)
M-2009-2092222	(Petition of Metropolitan Edison Company, Pennsylvania Electric Company, and Pennsylvania Power Company for approval of its Energy Efficiency and Conservation Plans)
M-2009-2112952	(Petition of Metropolitan Edison Company, Pennsylvania Electric Company, and Pennsylvania Power Company for approval of its Energy Efficiency and Conservation Plans)
M-2009-2112956	(Petition of Metropolitan Edison Company, Pennsylvania Electric Company, & Pennsylvania Power Company for approval of its Energy Efficiency and Conservation Plans)
A-2010-2176520	(Joint Application of West Penn Power Company, Trans-Allegheny Interstate Line Company & FirstEnergy Corp.)
A-2010-2176732	(Joint Application of West Penn Power Company, Trans-Allegheny Interstate Line Company & FirstEnergy Corp.)
P-2011-2273650	(Metropolitan Edison Company Default Service Programs)

P-2011-2273668	(Pennsylvania Electric Company Default Service Programs)
P-2011-2273669	(Pennsylvania Power Company Default Service Programs)
P-2011-2273670	(West Penn Power Company Default Service Programs)

NY PSC Cases:

Docket No.	***Case Name***
Case 11-E-0594	(Pennsylvania Electric Company Waverly District – moving POLR rates to market supply)

FERC Cases:

Docket No.	***Case Name***
ER93-471-000	(COS – FERC Rate Case: Cleveland Electric Illuminating Company v. Cleveland Public Power)

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT I-A-1:

> "Provide a summary discussion of the rate change request, including specific reasons for each increase or decrease. Also provide a breakdown which identifies the revenue requirement value of the major items generating the requested rate change."

RESPONSE:

Metropolitan Edison Company
Statement of Reasons for Rate Changes

Introduction

Metropolitan Edison Company ("Met-Ed" or the "Company") has filed a new tariff and accompanying supporting data setting forth a proposed distribution base rate increase and other proposed tariff revisions ("Rate Plan") for approval by the Pennsylvania Public Utility Commission ("Commission"). Met-Ed has not filed a general base rate case since 2006, which resulted in a distribution base rate decrease, and has not increased its base rates since 1992.

The Rate Plan proposes rates that would produce an increase in Met-Ed's annual distribution revenue of $151.9 million based on a fully projected future test year ending April 30, 2016 and reflecting the Company's proposed overall rate of return of 8.05% and a rate of return on the common equity portion of its capital structure of 10.9%. The average total-bill increases under the proposed rates vary by class of customers, and average class increases range from approximately 1.8% to 19.96% for customers that

receive default service from the Company. The monthly bill of a residential default service customer using 1,000 kilowatt-hours ("kWh") per month would increase from $116.56 to $137.34.

Principal Reasons For The Proposed Increase In Rates

Four principal factors are driving the Company's need to increase its distribution rates:

1. **Significant Growth In The Company's Investment In Plant In Service.** Met-Ed's investment in electric plant in service has increased by $507 million since it last filed a general base rate case.
2. **Increase In Depreciation Expense.** The growth in utility plant investment has caused the Company's annual depreciation expense to increase by $38 million for the fully projected future test year in this case as compared to the annual depreciation expense that the Company was permitted to recover in the rates established in its 2006 rate case.
3. **Unrecovered Investment In Meter Costs.** Depreciation expense has also increased as a result of the legislative mandate imposed by Act 129 of 2008, which added Section 2807(f) to the Pennsylvania Public Utility Code. Section 2807(f) requires electric distribution companies ("EDCs") to install Smart Meters for all customers. Under the Commission-approved Smart Meter Deployment Plan for Met-Ed, 95% of its customers will have Smart Meters installed by mid-2019. As a result, Met-Ed's investment in existing "legacy" meters has to be

recovered over their now much shorter remaining service lives, which added $8.4 to Met-Ed's annual depreciation expense.

4. **Deferred Storm Damage Expense.** Met-Ed's service area has experienced several severe storm events over the last four years, which caused extensive damage to its distribution system and caused the Company to incur significant storm damage remediation costs. With the Commission's prior approval, those expenditures were deferred for recovery in the Company's next base rate case. Therefore, in this case, Met-Ed is seeking to amortize $65 million of deferred storm expenses and has requested a return on the unamortized balance.

Notably, the factors driving Met-Ed's need for rate relief explained above have been partially offset by reductions in other components of Met-Ed's revenue requirement. Specifically, as a result of carefully managing operating and maintenance ("O&M") expenses and, in particular, administrative and general expenses, Met-Ed's O&M expenses, excluding depreciation and Smart Meter costs, are actually $4.0 million lower than the O&M expense, excluding depreciation, that the Company incurred during the future test year in its 2006 base rate case.

Due in large part to its substantial investment in utility plant and notwithstanding its success in containing O&M expenses, Met-Ed's overall rate of return, at present rates, is projected to be only 2.10% for the fully projected future test year. More importantly, the indicated return on common equity under present rates is anticipated to be (1.0)%, which is inadequate by any reasonable standard.

Principal Components of the Rate Plan

The Company's Rate Plan consists of the following principal components:

1. **Increased Distribution Base Rates**. Met-Ed is proposing distribution base rates that reflect its costs to furnish distribution service during the fully projected future test year and to provide a reasonable return on its investment in plant dedicated to public service.
2. **Storm Damage Charge Rider**. Met-Ed is proposing a Storm Damage Charge Rider that will add to its tariff an adjustment clause authorized by Section 1307(a) of the Pennsylvania Public Utility Code. The adjustment clause will impose a charge or credit on customers' bills to reflect the difference, on an annual basis, between storm damage expenses recovered in Met-Ed's base rates and the storm damage expense it actually incurs. The Storm Damage Charge Rider is a reasonable means for the Company to recover its actual storm damage costs – neither more nor less – on a timely basis.
3. **Roll-In To Base Rates Of Smart Meter Costs.** Met-Ed currently has a Smart Meter Technologies Charge Rider containing a Commission-approved adjustment clause that imposes a Smart Meter Technologies Charge to recover the costs of implementing its Smart Meter Deployment Plan ("Smart Meter Plan"). Met-Ed is proposing to include in its distribution base rate revenue requirement its fully projected future test year costs to implement its Smart Meter Plan and to recover those costs in its distribution base rates. Accordingly, Met-Ed is also proposing to reduce its Smart Meter Technologies Charge to zero. The Smart Meter

Technologies Charge Rider will remain in the Company's tariff as the mechanism to recover the cost of implementing its Smart Meter Plan, net of savings, in excess of such costs being recovered in base rates. Additionally, the roll-in to base rates will enable Met-Ed to clearly establish baselines for the Smart Meter costs being recovered in base rates and for those cost categories that it will need to track to determine future savings produced by the implementation of its Smart Meter Plan.

4. **Updating "Unbundled" Default Service-Related Uncollectible Accounts Expense**. Met-Ed recovers "unbundled" uncollectible accounts expense associated with providing default service, including its Purchase of Receivables Program for electric generation suppliers' accounts receivable, under its Default Service Support ("DSS") Rider and Hourly Pricing Default Service ("HPS") Rider. The charges imposed under the applicable provisions of the DSS Rider and HPS Rider are being updated in this filing to reflect current cost levels and to reconcile prior period costs and revenues.

5. **New Rules And Regulations**. Met-Ed, together with its affiliated EDCs in Pennsylvania (Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company), which are making contemporaneous distribution base rate filings, is proposing to adopt Rules and Regulations that will be uniform across all four companies. Establishing uniform Rules and Regulations will extend to the Companies' tariffs and tariff administration a level of standardization that will help create a uniform customer experience across their

Pennsylvania service territories; streamline their practices; and help to control administration costs.

6. **Elimination Of Certain Riders, Rate Schedules And Tariff Rules.** Certain riders, rate schedules and rules in Met-Ed's current tariff are legacies of the era when the Company furnished fully "bundled" generation, transmission and distribution service. Following the restructuring of the electric industry in Pennsylvania, those riders, rate schedules and rules are not applicable to the provision of unbundled distribution service or are obsolete for other reasons and, therefore, Met-Ed proposes to eliminate them.

The following table shows the composition of Met-Ed's proposed revenue increase by component:

	$ Thousands
Distribution Base Rates	149,328
Smart Meter Roll-In	3,315
DSS and HPS Riders	(716)
Total Revenue Increase	151,927
Percentage Increase Over Revenues At Existing Rates[1]	11.5%

1. The percentage was calculated based on total estimated revenue for the fully projected future test year consisting of distribution revenue and generation service revenue, assuming all customers receive default service at the Company's applicable default service rates.

Customer Impact/Bill Comparisons

As previously noted, if Met-Ed's proposed rates were fully implemented, a residential customer of the Company using 1,000 kWh of electricity per month and receiving default service would pay a total monthly bill of $137.34. That amount is

approximately the same as, or lower than, the monthly bills of default service customers using 1,000 kWh per month served by the three other major EDCs in Pennsylvania not affiliated with Met-Ed,[1] which range from $138.05 to $153.19 under those companies' existing rates.

Conclusion

The Rate Plan reflects the Company's need for adequate and timely rate relief to support the substantial amounts of additional investment it will be required to make to maintain and enhance reliability, replace aging infrastructure, and fully implement its Smart Meter Plan while continuing to furnish its customers the safe, reliable and high-quality electric service they have come to expect. Accordingly, it is critically important for both the Company and its customers that the Rate Plan be approved.

[1] Duquesne Light Company, PECO Energy Company and PPL Electric Utilities Corporation.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT I-A-2:

"Identify the proposed witnesses for all statements and schedules of revenues, expenses, taxes, property, valuation, and the like."

RESPONSE:

Witness	Statement Designation	Area of Testimony
C. Fullem	Statement 1	Overview of Distribution Base Rate Case Filing
R. D'Angelo	Statement 2	Revenue Requirements
K. Bortz	Statement 3	General Rules and Regulations, and New Riders
K. Siedt	Statement 4	Sales & Revenue Normalization and Rate Design
H. Stewart	Statement 5	Cost of Service
P. Larkin	Statement 6	Cash Working Capital
L. Gifford	Statement 7	Unbundled Uncollectible Expense, Smart Meters
C. Ciccone	Statement 8	New LED Streetlighting Schedule
Dr. M. Vilbert	Statement 9	Rate of Return
S. Staub	Statement 10	Cost of Capital and Rate of Return

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT I-A-3:

"Provide a single page summary table showing, at present and at proposed rates, together with references to the filing information, the following as claimed for the fully adjusted test year:

Revenues
Operating Expenses
Operating Income Rate Base
Rate of Return (produced)"

RESPONSE:

	Total Distribution At Present Rates* ($ millions) (Exhibit RAD-2 Page 1, Column 13)	Total Distribution At Proposed Rates* ($ millions) (Exhibit RAD-2 Page 3, Column 33)
Revenues	$ 285	$ 438
Operating Expenses	$ 255	$ 324
Operating Income	$ 30	$ 114
Rate Base	$1,413	$1,413
Rate of Return (produced)	2.10%	8.05%

*There is a difference in the total revenue requirements because of slight changes in the Default Service Support Rider of $(716).

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT I-B-1:

> "Provide a corporate history including the dates of original incorporation, subsequent mergers and acquisitions. Indicate all counties, cities and other governmental subdivisions to which service is provided, including service areas outside this Commonwealth, and the total number of customers or billed units in the areas served."

RESPONSE:

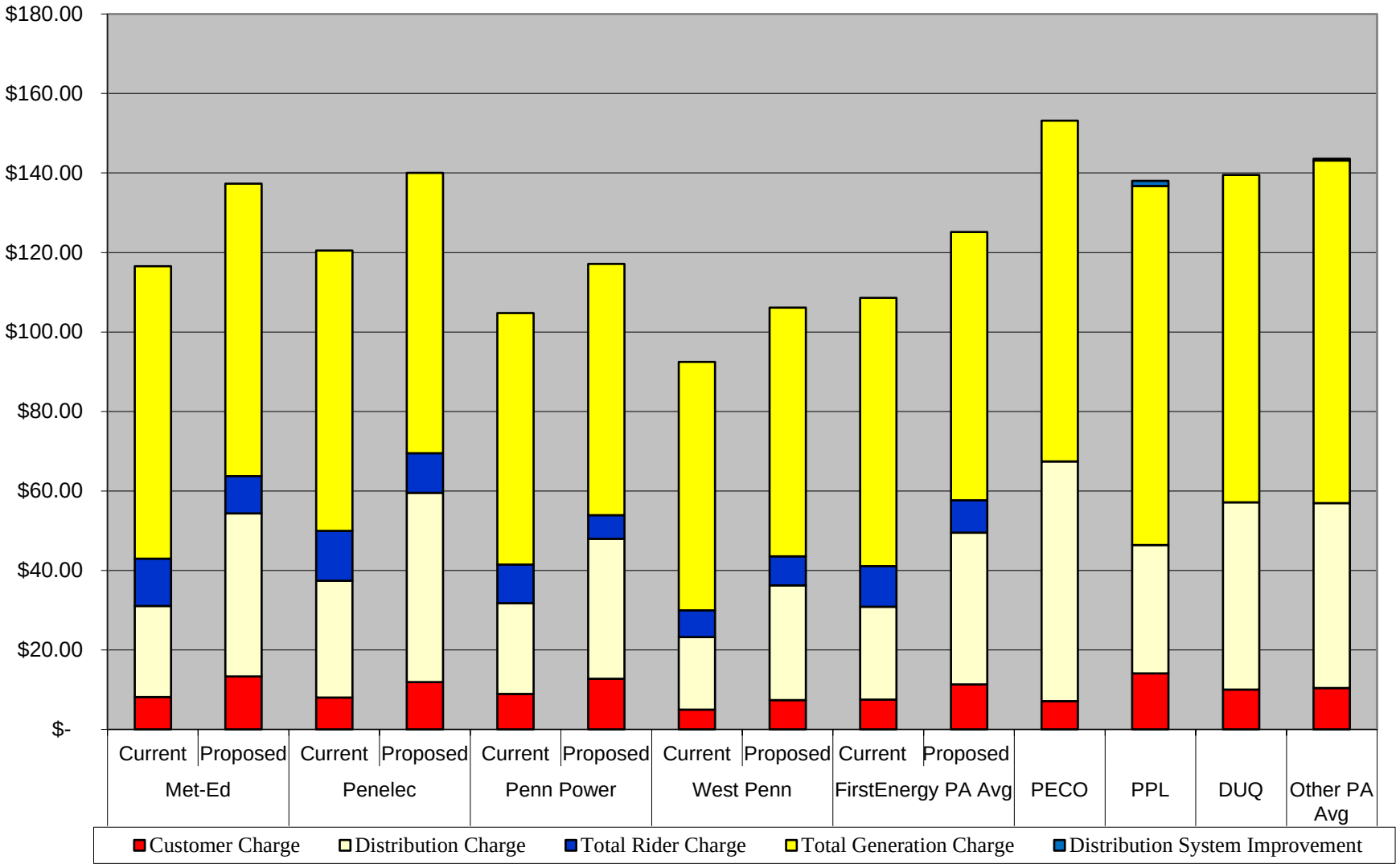
Metropolitan Edison Company ("Met-Ed" or "Company"), a Pennsylvania corporation, was formed by a consolidation and merger of Metropolitan Edison Company (a predecessor constituent company of the same name as Met-Ed) and Metropolitan Electric Light & Power Company by an agreement dated June 8, 1922 in accordance with the provisions of the Action of 1909, P. L. 408, and letters patent were issued to Met-Ed on July 24, 1922. That predecessor constituent company of the same name as Met-Ed was likewise formed as the result of various successive mergers and consolidations. Since its incorporation, Met-Ed has acquired by purchase the properties and franchises of numerous electric light, heat and power and water power companies chartered to serve various parts of the area now embraced within Met-Ed's territory.

In 1946, General Public Utilities, Inc. (later "GPU Inc.") was created, forming the umbrella under which Met-Ed, Pennsylvania Electric Company ("Penelec") and Jersey Central Power & Light Company conducted business. On November 7, 2001, GPU merged with FirstEnergy Corp. Since that merger, Met-Ed has been a wholly owned subsidiary of FirstEnergy Corp.

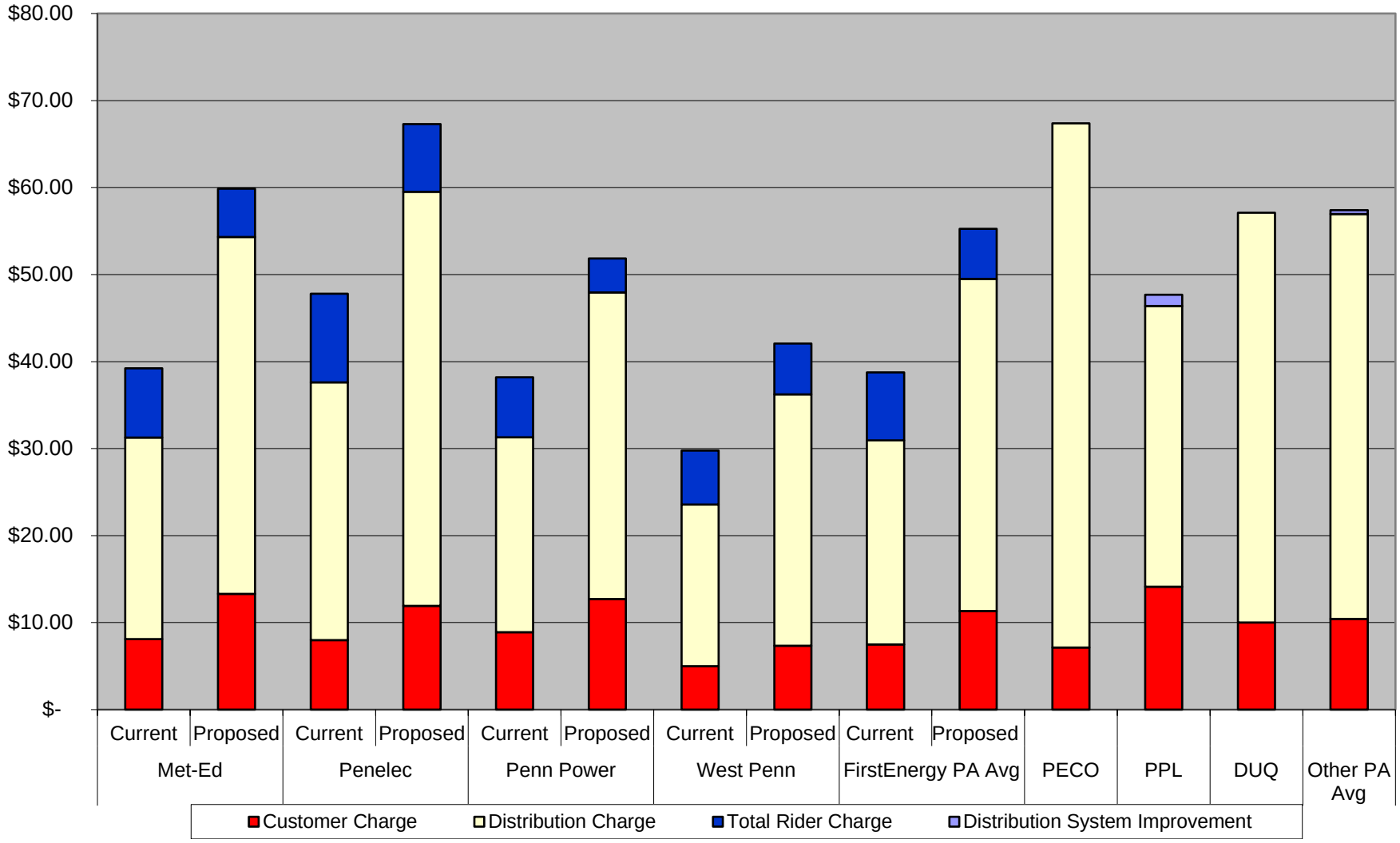
The Company's principal business is the transmission, distribution and sale of electricity in eastern and south central Pennsylvania. Met-Ed is affiliated with three other Pennsylvania electric distribution utilities (Penelec, Pennsylvania Power Company and West Penn Power Company), as well as six additional sister distribution utilities in New Jersey, Ohio, Maryland and West Virginia. Other affiliates include FirstEnergy Service Company (a service company) and various regulated transmission and unregulated competitive energy companies.

The Company provides retail service to approximately 557,000 customers in all or portions of fourteen counties in the eastern and south central parts of Pennsylvania. The municipalities which the Company serves are listed in the Company's filed Electric Service Tariff, Electric Pa. P.U.C. No. 52.

PA 1,000 kWh Residential Default Service Bill Comparison



PA 1,000 kWh Residential Delivery Bill Comparison



Met-Ed/Penelec/Penn Power/West Penn
Statement No. 7

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2014-2428745

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. R-2014-2428743

PENNSYLVANIA POWER COMPANY
DOCKET NO. R-2014-2428744

WEST PENN POWER COMPANY
DOCKET NO. R-2014-2428742

Direct Testimony
of
Laura W. Gifford

List of Topics Addressed

Unbundling of Uncollectible Accounts Expense
Smart Meter Revenue Requirements
Smart Meter Cost Savings Baselines

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DIRECT TESTIMONY
OF
LAURA W. GIFFORD

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Laura W. Gifford. My business address is 2800 Pottsville Pike, Reading, Pennsylvania 19612.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company as a Rate Analyst V in the Rates and Regulatory Affairs Department – Pennsylvania.

Q. What are your responsibilities as a Rate Analyst V?

A. Generally, the Rates and Regulatory Affairs Department provides regulatory support for Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power") and West Penn Power Company ("West Penn") (each of which may be referred to as "Company" and/or collectively as the "Companies"). I am responsible to the Manager of Rates and Regulatory Affairs for the preparation and coordination of the Companies' accounting and financial data in all their rate-related matters before the Pennsylvania Public Utility Commission ("PUC" or "Commission"), the New York State Public Service Commission and the Federal Energy Regulatory Commission ("FERC"), including the preparation of statements and reports addressing, among other things, smart meters, energy costs, non-utility generation costs, default service support charges including uncollectible accounts expense, quarterly earnings, and other financial matters.

Q. What is your educational background and professional experience?

A. I am a graduate of The College of Wooster where I received a Bachelor of Arts degree with a major in Business Economics in 1978. I have over seventeen years of experience with FirstEnergy Corp. and GPU Energy. My work experience is more fully described in Appendix A.

Q. Have you previously testified in proceedings before the Commission?

A. Yes. I have previously testified before this Commission, as further outlined in Appendix A.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Met-Ed, Penelec, Penn Power and West Penn. My testimony equally applies to all of the Companies, unless otherwise stated.

Q. Please describe the purpose of your direct testimony.

A. The purpose of my testimony is to discuss the unbundling of default service related uncollectible accounts expense and to describe the roll-in of the revenue requirement associated with Smart Meters into distribution base rates, including the development of cost baselines for determining savings resulting from the deployment of smart meters.

Q. Have you prepared any exhibits to accompany your testimony?

A. Yes. Met-Ed Exhibit LWG-1, Penelec Exhibit LWG-1, Penn Power Exhibit LWG-1 and West Penn Exhibit LWG-1 (collectively, "Exhibits LWG-1") and Met-Ed/Penelec/Penn Power/West Penn Exhibits LWG-2 and LWG-3 were prepared by me or under my supervision and are described in detail later in my testimony. In addition, I am

sponsoring Riders I and J to Met-Ed Company Exhibit 1; Riders I and J to Penelec Company Exhibit 1; Riders I and J to Penn Power Company Exhibit 1; and Riders I and J to West Penn Company Exhibit No. 1.

II. UNCOLLECTIBLE ACCOUNTS EXPENSE

A. Met-Ed, Penelec, and Penn Power

Q. Did Met-Ed, Penelec, and Penn Power previously unbundle uncollectible accounts expense associated with the provision of default generation service?

A. Yes. In accordance with the Commission's Final Order in their Default Service Program proceedings at Docket Nos. P-2009-2093053 and P-2009-2093054, Met-Ed and Penelec fully unbundled uncollectible accounts expense associated with default service for residential, commercial and industrial customers. Specifically, on January 1, 2011, the unbundled uncollectible accounts expense associated with default service and electric generation supplier ("EGS") service was removed from distribution rates and since then has been recovered through each Company's Default Service Support ("DSS") Rider on a non-bypassable, non-reconcilable basis. As part of that proceeding, Met-Ed and Penelec also each established a Purchase of Receivables ("POR") program for their residential and small commercial customers.

Penn Power similarly fully unbundled uncollectible accounts expense associated with default service for residential, commercial and industrial customers in accordance with the Commission's Final Order in its Default Service Program proceeding at Docket No. P-2010-2157862. Specifically, on June 1, 2011, the unbundled uncollectible accounts expense associated with default service and EGS service was removed from distribution rates and thereafter recovered through the DSS Rider on a non-bypassable, non-

reconcilable basis. As part of that proceeding, Penn Power also established a POR for its residential and small commercial customers.

Q. What changes, if any, are Met-Ed, Penelec, and Penn Power proposing in these proceedings as to the recovery of uncollectible accounts expense?

A. In a Commission-approved settlement[1] in their most recent default service proceeding (the "Default Service Settlement"), Met-Ed, Penelec, and Penn Power committed that, effective June 1, 2015, the uncollectible accounts expense associated with the provision of hourly-priced service to industrial customers would no longer be recovered through the DSS Riders and instead would be recovered in the default service rates established pursuant to those Companies' Hourly Priced Default Service ("HPS") Riders.

Q. Are any changes required in the Companies' base rate cases to update the uncollectible accounts expense in the DSS Rider for residential and commercial customers and the HPS Rider for industrial customers for Met-Ed, Penelec and Penn Power?

A. Yes. Since Met-Ed, Penelec and Penn Power have included a claim for uncollectible accounts expense with these rate filings based on data for the fully projected future test year ("FPFTY") ending April 30, 2016, those amounts will need to be unbundled to determine what portion of the expense will remain in distribution base rates, what portion will be included in the DSS Rider for residential and commercial customers, and what portion will be included in the HPS Rider for industrial customers.

[1] *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company for Approval of their Default Service Programs*, Docket Nos. P-2013-2391368 (Met-Ed), P-2013-2391372 (Penelec) and P-2013-2391375 (Penn Power)(Order entered July 24, 2014).

Q. Please explain the methodology used to calculate the updated uncollectible accounts expenses in the DSS Riders and HPS Riders for Met-Ed, Penelec and Penn Power.

A. To determine an appropriate amount of uncollectible accounts expense for each Company, I first calculated the ratio of (1) the default service revenue in the budget for the FPFTY plus the projected revenues billed to customers on behalf of EGSs for that same time period to (2) the total retail revenue in the FPFTY ending April 30, 2016, plus the projected revenues billed to customers on behalf of EGSs. I then multiplied this ratio by the total uncollectible accounts expense in the FPFTY budget for each Company yielding the default service-related uncollectible accounts expense. This total Company amount of default service-related uncollectible accounts expense was then allocated to the residential, commercial and industrial customer classes based on the weighted average of uncollectible write-offs over the two-year period, June 2012 through May 2014. The customer class allocated amount was then divided by projected kWh for that customer class to determine the appropriate rate.

The calculation of the uncollectible accounts expense components of the DSS Rider rates and HPS Rider rates are shown in Exhibits LWG-1 for each of the Companies, and which rates are reflected in Riders I and J in each of Companies' Exhibits 1.

Q. Where can the total uncollectible accounts expense amounts for the FPFTY be found?

A. The total amounts of uncollectible accounts expense in the FPFTY budget are set forth in FERC Account No. 904, as shown in Attachment A to Exhibits RAD-55 for Met-Ed,

Penelec and Penn Power, which are being sponsored by Mr. Richard A. D'Angelo in Met-Ed/Penelec/Penn Power/West Penn Statement No. 2.

B. West Penn

Q. Has West Penn previously unbundled any portion of its uncollectible accounts expense?

A. No. West Penn currently recovers all uncollectible accounts expense through base distribution rates.

Q. Is West Penn proposing in this proceeding to fully unbundle its uncollectible accounts expense?

A. Yes. West Penn committed in the Default Service Settlement to propose, in its next base rate case, the unbundling of all uncollectible accounts expense associated with default service and its POR program similar to Met-Ed, Penelec, and Penn Power.

Q. Is West Penn also proposing to include the uncollectible accounts expense charge for the Industrial customer class in its HPS Rider?

A. Yes. The calculation of the uncollectible accounts expense component of the HPS Rider rate for West Penn is shown in West Penn Exhibit LWG-1, column 3.

Q. How does West Penn propose to fully unbundle its uncollectible accounts expense?

A. West Penn will utilize the same methodology that was used to update the unbundling of the uncollectible accounts expense for Met-Ed, Penelec and Penn Power in these proceedings. Details of these calculations by customer class, including the unbundled default service-related portion of the total uncollectible accounts expense in FERC

Account No. 904, are contained in West Penn Exhibit LWG-1. In addition, the total amount of uncollectible accounts expense in the FPFTY budget is provided in FERC Account No. 904 shown in West Penn Exhibit RAD-55 attached to Mr. D'Angelo's testimony.

Q. Please explain the uncollectible accounts expense components that will be added to the existing West Penn DSS Rider and HPS Riders.

A. West Penn already has DSS Riders and HPS Riders in West Penn Electric Pa. P.U.C. No. 39 (general application) and West Penn Electric Pa. P.U.C. No. 37 (applicable only to Pennsylvania State University, an industrial customer) that were approved as part of its default service program at Docket No. P-2011-2273670. West Penn is proposing to add uncollectible accounts expense components to the DSS Rider in West Penn Tariff No. 40[2] to collect the default service-related uncollectible accounts expense on a non-reconcilable, non-bypassable basis similar to Met-Ed, Penelec and Penn Power. This will allow West Penn to collect the default service and POR-related uncollectible accounts expense for residential and commercial customers in its DSS Rider. Both West Penn tariffs will have similar changes to the HPS Riders to allow for the collection of the uncollectible accounts expense for industrial customers. The proposed updates to the West Penn DSS Riders and HPS Riders are shown in West Penn Company Exhibit No. 1, Riders I and J, and West Penn Company Exhibit No. 2, Rider I.

[2] West Penn is proposing new tariffs in this instant proceeding. Therefore, they will be numbered with the next sequential number.

West Penn proposes to annually update the computation for the default service related-uncollectible accounts expense in the revised West Penn DSS Rider and HPS Riders similar to Met-Ed, Penelec and Penn Power.

Q. Will the adjustment to the retail default service prices for uncollectible accounts expenses be a component of the reconciliation of the West Penn DSS Rider and HPS Riders?

A. No. Consistent with the process for Met-Ed, Penelec and Penn Power, reconciliation will address only the revenues billed to customers for default service and costs actually incurred by the Company associated with the default service program.

Q. What is contained in Met-Ed/Penelec/Penn Power/West Penn Exhibit LWG-2?

A. Met-Ed/Penelec/Penn Power/West Penn Exhibit LWG-2 provides a summary of the unbundling for each Company. The exhibit shows the separation of the total uncollectible accounts expense for each Company into default service-related and distribution based on the calculations contained in Exhibits LWG-1.

III. SMART METER REVENUE REQUIREMENTS AND COST SAVINGS BASELINES

Q. What are the Companies proposing in this proceeding relative to the costs from their Commission-approved Revised Smart Meter Deployment Plan?

A. Met-Ed, Penelec, Penn Power and West Penn are proposing to roll the adjusted SMT-C Rider rate base, revenues and costs for the fully projected future test year into the determination of their distribution rate revenue requirement rather than collecting the costs in their existing Smart Meter Technologies Charge ("SMT-C") Riders.

Consequently, the Smart Meter rates in each of the Companies' SMT-C Riders will be set to zero upon the implementation of new rates from this proceeding. The Riders will be available to the Companies when smart meter revenue requirements exceed the amount rolled into distribution base rates or when billable savings are achieved.

Q. Where can the smart meter revenue requirements that are being rolled into distribution base rates be found?

A. The smart meter revenue requirements for the FPFTY are identified on page 5 of the individual Company Exhibits RAD-2 presented by Mr. D'Angelo for Met-Ed ($19.0 million), Penelec ($20.3 million), Penn Power ($12.6 million) and West Penn ($47.1 million).

Q. Why is it appropriate for the Companies to move smart meter costs into distribution base rates?

A. First, Act 129 of 2008 provides that electric distribution companies may recover smart meter costs through base rates or a rider mechanism. While the Companies chose to establish the SMT-C Rider to facilitate recovery of initial smart meter costs, they also proposed to have the ability in a future proceeding to propose rolling existing Smart Meter costs into base rates while continuing to recover new smart meter costs through a reconcilable automatic adjustment clause. Following review of that proposal, the Commission agreed that base rate recovery of smart meter costs could appropriately be considered in a future proceeding.[3]

[3] See *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company for Approval of Smart Meter Technology Procurement and Installment Plan,* Docket No. M-2009-2123950 (Order entered August 3, 2010).

Second, while the Companies expect smart meter costs to escalate over the next several years as smart meters are deployed throughout their territories, once deployment is complete, smart meter costs are expected to be more stable and predictable and therefore more akin to costs recovered in base rates than the volatile, more unpredictable costs included in riders authorized under Section 1307(e) of the Public Utility Code.

Third, there is ample precedent for rolling into base rates categories of costs that were previously recovered through a reconcilable automatic adjustment clause. For example, certain state taxes are routinely rolled into base rates after being recouped through the State Tax Adjustment Surcharge ("STAS") between rate cases. Similarly, and perhaps more on point, the Distribution System Improvement Charge ("DSIC") implemented by many of the Commonwealth's major jurisdictional water companies and now electric companies is "zeroed out" in base rate proceedings and the depreciated original cost, *i.e.*, unrecovered investment, and related costs of replacement property previously included in the DSIC, are added to base rates.

Q. Please describe how the Companies will transition the recovery of smart meter costs from the SMT-C Rider to distribution base rates.

A. The Companies anticipate that the distribution base rates established in this proceeding will become effective on or about May 1, 2015, and those rates will include the smart meter revenue requirements approved in this proceeding. At that time, the SMT-C rate for each Company will be set to zero. However, the Companies will still need to reconcile revenues and costs for the July 1, 2014 through June 30, 2015 period[4] and file

[4] The SMT-C reconciliation year, as defined in the SMT-C Rider, is from July 1 through June 30.

their 1307(e) reconciliation statements. Any over or under collection balances from this reconciliation process will be held on the books, with interest, until such time that a Company reactivates the SMT-C Rider rate, which, as previously noted, will occur when either smart meter revenue requirements exceed the amount rolled into distribution base rates or when billable savings are achieved. Each Company will track the twelve months of costs and savings for each reconciliation year to determine if reinstatement is appropriate. The Companies will file SMT-C Rider rates on August 1, 2015, if appropriate, and each August 1 thereafter with a determination of whether there will be an incremental SMT-C rate for the following calendar year. The reconciliation year of July through June and the SMT-C rates effective the following January through December is in accordance with the Companies' existing Commission-approved SMT-C Riders.

Q. Will the Companies be measuring savings achieved from the deployment of smart meters and flowing those savings through the SMT-C Rider?

A. Yes. In the Companies' most recent smart meter proceedings, the Commission approved a December 31, 2013 cost baseline for purposes of measuring savings achieved from the deployment of smart meters.[5] In addition, the Commission directed the Companies to provide detailed information on cost savings baseline measures as of December 31, 2013 and explain how cost savings will be calculated as part of the next SMT-C rate filing to be made August 1, 2014. It further requested that the Companies file similar information each year with subsequent SMT-C rate filings.

[5] *See Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company For Approval of Their Smart Meter Deployment Plan*, Docket Nos. M-2013-2341990, M-2013-2341991, M-2013-2341993, and M-2013-2341994 (Order entered March 6, 2014).

Q. Will the Companies be filing December 31, 2013 baseline data in this proceeding?

A. No. The Companies are proposing to establish a cost baseline as of April 30, 2016 to measure savings achieved from the deployment of smart meters. The Companies believe the April 30, 2016 baseline date is more appropriate than December 31, 2013 because: (1) it is consistent with the end of the FPFTY period which is being used to determine the smart meter revenue requirements being rolled into base rates; and (2) the Companies do not anticipate achieving any meaningful savings from the deployment of smart meters until sometime after May 2016.

Q. How will cost savings resulting from smart meters be identified and flowed through to customers?

A. First, each Company is establishing smart meter baseline costs for eight categories as of April 30, 2016, and one category as of March 31, 2014,[6] as shown in Met-Ed/Penelec/Penn Power/West Penn Exhibit LWG-3. Four of those categories were identified by the Companies in their Smart Meter Deployment Plan that was approved by the Commission: (1) meter reading; (2) meter services; (3) back-office; and (4) contact center. In addition, the Companies have committed to investigate five additional categories[7]: (1) reduction in theft of service; (2) revenue enhancements; (3) avoided capital costs; (4) distribution operations; (5) and load research. Once the baseline costs

[6] Baseline costs for the "avoided capital cost" category, which includes legacy meters, were established based on the March 31, 2014 material and supply inventories included in rate base.

[7] As part of the Companies' most recent smart meter proceeding, the Companies agreed to investigate certain costs categories that were identified by the Office of Consumer Advocate ("OCA"). In addition, West Penn committed, as part of an earlier smart meter settlement at Docket No. M-2009-2123951, to investigate certain costs. The Companies are addressing all of the items identified by OCA and in the earlier West Penn settlement, except for credit and collections. The Companies have not included this category in their baseline because the Commission has not adopted rules authorizing the use of smart meter for customer shut-offs, which would be the predominant, if not sole, source of savings in this category.

are established and approved by the Commission, any cost savings moving forward will be reflected as an offset to the costs that will be included in the SMT-C Riders.

Q. How did the Companies determine the cost baseline for the four categories that were part of their Smart Meter Deployment Plan?

A. ***Meter Reading***. The Companies have developed the projected baseline by tracking the following: (i) labor costs, which include headcount, salary, overtime benefits and taxes; (ii) meter reader reductions due to attrition and retirement; (iii) total severance costs; (iv) total cost of uniform supplies; (v) fleet costs, which include lease, license, direct parts and labor, indirect parts and labor, and fuel; (vi) the estimated expense of personal mileage; (vii) handheld costs, which include both maintenance and replacement costs; and (viii) the cost of claims.

Meter Services. The Companies have developed the projected baseline by tracking the following: (i) labor costs-original roles, which include headcount, salary, overtime benefits and taxes; (ii) total severance costs; (iii) total cost of uniform supplies; (iv) fleet costs, which include lease, license, direct parts and labor, indirect parts and labor, and fuel; (v) original tablet costs, which include both maintenance and replacement costs; (vi) new device costs; (vii) staff retraining costs; and (viii) labor costs-new roles, which include headcount, salary, overtime benefits and taxes.

Back-office. The Companies have developed the projected baseline by tracking the following: (i) labor costs, which include headcount and salary, and severance costs; and (ii) staffing updates.

Contact Center. The Companies have developed the projected baseline by tracking the following: (i) labor costs, which include headcount and salary; and (ii) staffing updates.

Q. How will the Companies determine the cost baselines for the five additional categories that were not part of their Smart Meter Deployment Plan?

A. ***Reduction in Theft of Service***. Revenues recovered due to theft of service currently are not separately recorded on the Companies' books. If the Companies are successful in recovering any revenues as a result of theft of service, they are booked as retail revenues. Therefore, the baseline for this category is zero and when the Companies do record any recovered revenues due to the discovery of theft, the savings will be flowed to customers through the SMT-C Rider.

Revenue Enhancements. This category refers to a reduction in the lag between the time a meter is read and when a bill is produced. The Companies currently recognize a 1.5 day lag, as supported by the Direct Testimony of Patricia M. Larkin in Met-Ed/Penelec/Penn Power/West Penn Statement No. 6. Because smart meters could possibly reduce this lag, a baseline cost associated with this 1.5 day delay has been established for purposes of measuring savings.

Avoided Capital Costs. This category refers to legacy meters and meter services handheld equipment used for meter reading that the Companies will no longer have to purchase as they are replaced with smart meters. As noted earlier, baseline costs were established based on the March 31, 2014 material and supply inventories included in rate base. Savings will accrue as these legacy inventories get smaller.

Distribution Operations. This category refers to the costs associated with sending a utility crew to a customer's location in response to a customer reported power outage. Smart meters could reduce the number of these "truck rolls" by allowing the Company to remotely determine whether the smart meter at the customer's location still has power. If the smart meter still has power, the problem is likely on the customer side of the meter and a truck roll may be avoided entirely. The Companies do not currently track, and have not separately budgeted for, costs associated with truck rolls where the problem is on the customer side of the meter. Therefore, the Companies are utilizing a baseline of zero and all savings will be shown in the form of a negative value in this category. The Companies will track the number of truck rolls avoided as a result of smart meters and will determine cost savings by looking at vehicle fuel expense, line department employee payroll, including overtime and training expenses.

Load Research. This category refers to a statistical sampling of customers with specialized interval meters that provide information to the Companies so as to determine appropriate load shapes for each customer class. The Companies are not currently conducting load research; therefore, there are no costs for load research in the budget. However, there are interval meters in the field that are capable of being used for load research and it is the cost of those existing load research meters that are in the baseline.

Q. When will measured savings be included in the SMT-C Riders?

A. The savings will be included in the SMT-C Riders once they are substantial enough to be billable. The Companies will measure savings on a monthly basis and accumulate the amount of cost savings during each reconciliation year and include billable savings either

in the form of a negative SMT-C rate or as an offset to costs in the SMT-C rates to be filed August 1 and effective the following January.

Q. What do you mean that the savings must be billable?

A. Met-Ed, Penelec, and Penn Power residential, commercial and industrial SMT-C rates, as well as West Penn commercial and industrial SMT-C rates, are billed on a twelve-month average meter count. The billing system can bill rates that are one hundredth of a cent; therefore, the amount of savings must be 12 cents per customer in order to be billable. At West Penn, the SMT-C residential rate is on a kWh basis, so the amount of accumulated savings should exceed $0.00001 for an average 1000 kWh customer.

Q. Will incremental smart meter costs or savings be included in the SMT-C Rider on a permanent basis?

A. No. During future base rate proceedings, the Companies will propose to move the recovery of any incremental costs or savings from the SMT-C Rider to base distribution rates.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Resume: Education and Experience of Laura W. Gifford

Education:

1978	Bachelor of Arts Degree in Business Economics - The College of Wooster, Wooster, Ohio
1999 – Present	Various utility industry conferences and seminars addressing issues in the areas of Utility Finance, Electric Utility Operations, Rate Design, FERC Organization and Transmission Pricing

Experience:

7/78 – 3/79	Trust Accountant - Union Commerce Bank, Cleveland, Ohio
5/79 – 5/82	New Business and Pension Coordinator – Connecticut General Life Insurance Company/CIGNA, Buffalo, NY
9/88 – 9/92	Director of Mom's Morning Out – St. John's Lutheran Church, Sinking Spring, PA
9/92 – 10/94	Office Manager/Medical Secretary – Southeastern Berks Internal Medicine Associates, Reading PA
10/94 – 2/97	Senior Customer Service Representative/Medical Claims Processor – AETNA Life Insurance Company, Reading, PA
2/97 – 8/98	Employed as Customer Service Representative – Customer Service Department of GPU Energy
8/98 – 5/00	Rate Analyst – FERC Activity within the Rate Department – GPU Energy
5/00 – 11/01	Rate Analyst – Rate Activity within the Rate Department – GPU Energy
11/01 – 3/03	Associate Business Analyst – Rates & Regulatory Affairs – Pennsylvania – FirstEnergy Service Company
3/03 – 3/05	Business Analyst – Rates & Regulatory Affairs – Pennsylvania – FirstEnergy Service Company
3/05 – 12/06	Advanced Business Analyst – Rates & Regulatory Affairs – Pennsylvania – FirstEnergy Service Company
12/06 – 3/12	State Regulatory Analyst IV / Senior Business Analyst – Rates & Regulatory Affairs – Pennsylvania – FirstEnergy Service Company
3/12 – Present	State Regulatory Analyst V – Rates & Regulatory Affairs – Pennsylvania – FirstEnergy Service Company

Prepared and presented testimony in the following rate-related cases:

Pa. P.U.C. Cases:	Docket Nos.	R-00016219
		R-00016220
		C-20028926
		M-2008-2041151
		M-2008-2041153
		M-2008-2041167
		M-2008-2041169

M-2008-2036188
M-2009-2105616
M-2009-2105619
P-2010-2157862
M-2010-2180408
M-2010-2180413
M-2011-2241863
M-2011-2241892
M-2012-2303491
M-2012-2303492
M-2012-2303487

Assisted in development and preparation in the following rate related cases:

Pa. P.U.C. Cases: Docket Nos.	R-00061366
	R-00061367
	R-00016851C0001
	R-00016852C0001
	R-00016853C0001
	P-00062235
	P-00072259
	P-2008-2020257
	P-2008-2036197
	P-2008-2036188
	P-2009-2093053
	P-2009-2093054
	A-2010-2176520
	A-2010-2176732
	P-2011-2273650
	P-2011-2273668
	P-2011-2273669
	P-2011-2273670
	P-2013-2341990
	P-2013-2341991
	P-2013-2341993
	P-2013-2341994
	P-2013-2351260
NY P.S.C Cases: Case Nos.	11-E-0594
	13-E-0067
FERC Case: Docket No.	ER99-3393-000
	ER00-3567-000
	EL00-88-000

Metropolitan Edison Company

Default Service Support Charge Rider / Hourly Pricing Default Service Rider

Default Service Related Uncollectible Accounts Expense

Based on 12 Months Ending April 30, 2016

(000's)

Line No.	Description	DSS Rider Residential (1)	DSS Rider Commercial (2)	HPS Rider Industrial (3)	Total Company (4)
1	Total Company Revenue and billed EGS revenue at April 30, 2016				$ 951,772
2	Default Service Revenue at April 30, 2016				$286,330
3	Residential and Commercial Generation Revenues billed for EGSs at April 30, 2016				295,072
4	Total Generation and Transmission Revenues (line 2 + line 3)				$581,402
5	Percentage of Generation/Transmission Revenue to Total Revenue (line 4 / line 1)				61%
6	Uncollectible Accounts Expense at April 30, 2016				12,136
7	Default Service Related Uncollectible Accounts Expense at April 30, 2016 (line 5 X line 6)				$ 7,403
8	Allocation of Default Service Related Uncollectible Accounts Expense to Rate Classes (A)	95.60%	3.93%	0.47%	100.00%
9	Default Service Related Uncollectible Accounts Expense by Customer Class (Line 7 X Line 8)	$ 7,077	$ 291	$ 35	$ 7,403
10	kWh at April 30, 2016	5,408,762	2,997,814	5,391,799	13,798,375
11	Default Service Related Uncollectible Accounts Expense (line 9 / line 10)	0.13085 cents per kWh	0.00971 cents per kWh	0.00065 cents per kWh	

(A) Allocated based on a 2 year average of net write offs.

Metropolitan Ediston Company
Pennsylvania Electric Company
Penn Power Company
West Penn Power Company

Unbundled Uncollectible Accounts Expense

Line No.	Company	Description	Normalized Uncollectibles in FFTY	per Budget Uncollectibles in FFTY	Uncollectibles in Base Rates A&G Normalization
1	Met-Ed	Total	12,136	12,136	
2		Default Service	7,403	8,077	(674)
3		Distribution	4,733	4,059	674
4	Penelec	Total	8,959	8,959	
5		Default Service	4,927	5,420	(493)
6		Distribution	4,032	3,539	493
7	Penn Power	Total	1,610	1,610	
8		Default Service	1,031	2,042	(1,011)
9		Distribution	579	(432)	1,011
10	West Penn	Total	10,642	10,642	
11		Default Service	6,917	-	6,917
12		Distribution	3,725	10,642	(6,917)

Metropolitan Edison Company
Pennsylvania Electric Company
Pennsylvania Power Company
West Penn Power Company

Cost Baseline for Savings as a Result of the Deployment of Smart Meters

Line No.	Description	Met-Ed	Penelec	Penn Power	West Penn	Total PA Companies
1	Meter reading (Page 2)	$ 5,596,570	$ 5,760,672	$ 1,548,187	$ 7,338,454	$ 20,243,883
2	Meter services (Page 4)	2,424,995	1,942,292	515,189	1,716,634	6,599,110
3	Back-office (Page 6)	686,873	729,613	192,340	1,353,074	2,961,900
4	Contact Center (Page 8)	2,741,626	2,940,535	778,626	3,258,602	9,719,389
5	Theft of service reduction	0	0	0	0	0
6	Revenue enhancement (Page 10)	500,000	484,000	130,000	500,000	1,614,000
7	Avoided capital costs (Page 10)	42,697	54,561	6,135	59,352	162,745
8	Distribution operations	0	0	0	0	0
9	Load research (Page 11)	9,525	13,923	381	5,502	29,331
10	Total	$ 12,002,286	$ 11,925,596	$ 3,170,858	$ 14,231,618	$ 41,330,358

Meter Reading
Cost Baseline for Smart Meter Benefit
For the Twelve Months Ending April 2016

Line No.	Total Meter Reading Costs	Total Headcount	Total
1	*Met-Ed*	68	$ 5,596,570
2	*Penelec*	71	$ 5,760,672
3	*Penn Power*	18	$ 1,548,187
4	*West Penn Power*	89	$ 7,338,454

	Labor Costs	Headcount	Salary	Severance Costs
5	*Met-Ed*	68	$ 4,975,224	$
6	*Penelec*	71	$ 5,216,531	$
7	*Penn Power*	18	$ 1,400,051	$
8	*West Penn Power*	89	$ 6,422,219	$

	Uniforms/Supplies	Uniforms/ Supplies Costs
9	*Met-Ed*	$ 27,735
10	*Penelec*	$ 37,080
11	*Penn Power*	$ 40,885
12	*West Penn Power*	$ 48,328

	Fleet Costs	Fleet Costs
13	*Met-Ed*	$ 593,611
14	*Penelec*	$ 507,061
15	*Penn Power*	$ 107,251
16	*West Penn Power*	$ 867,907

	Handheld Costs	Replacement Costs	Maintenance Costs
17	*Met-Ed*	$	$
18	*Penelec*	$	$
19	*Penn Power*	$	$
20	*West Penn Power*	$	$

	Claims	Claims Costs
21	*Met-Ed*	$
22	*Penelec*	$
23	*Penn Power*	$
24	*West Penn Power*	$

(1) Inputs for Cost Centers 440021 - ME Meter Reading, 450020 - PN Meter Reading South, 450022 - PN Meter Reading North, 433251 - Penn Power Meter Reading, 490144 - West Penn Meter Reading Excluding Waynesboro, 490201 - West Penn Meter Reading Waynesboro from Budget

Meter Reading
Cost Baseline for Smart Meter Benefit by FERC Accounts
For the Twelve Months Ending April 2016

Line No.					
	Salary				
	Met-Ed				
1	FERC Account	593	Maintenance Overhead Lines	$	177,440
2	FERC Account	902	Meter Reading Expense		4,797,784
3			Total	**$**	**4,975,224**
	Penelec				
4	FERC Account	593	Maintenance Overhead Lines	$	102,034
5	FERC Account	902	Meter Reading Expense		5,114,497
6			Total	**$**	**5,216,531**
	Penn Power				
7	FERC Account	593	Maintenance Overhead Lines	$	7,884
8	FERC Account	902	Meter Reading Expense		1,392,167
9			Total	**$**	**1,400,051**
	West Penn Power				
10	FERC Account	593	Maintenance Overhead Lines	$	111,800
11	FERC Account	902	Meter Reading Expense		6,310,419
12			Total	**$**	**6,422,219**
	Uniform/Supplies Costs				
	Met-Ed				
13	FERC Account	902	Meter Reading Expense	**$**	**27,735**
	Penelec				
14	FERC Account	902	Meter Reading Expense	**$**	**37,080**
	Penn Power				
15	FERC Account	902	Meter Reading Expense	**$**	**40,885**
	West Penn Power				
16	FERC Account	902	Meter Reading Expense	**$**	**48,328**
	Fleet Costs				
	Met-Ed				
17	FERC Account	593	Maintenance Overhead Lines	$	21,165
18	FERC Account	902	Meter Reading Expense		572,446
19			Total	**$**	**593,611**
	Penelec				
20	FERC Account	593	Maintenance Overhead Lines	$	9,898
21	FERC Account	902	Meter Reading Expense		497,163
22			Total	**$**	**507,061**
	Penn Power				
23	FERC Account	593	Maintenance Overhead Lines	$	603
24	FERC Account	902	Meter Reading Expense		106,648
25			Total	**$**	**107,251**
	West Penn Power				
26	FERC Account	593	Maintenance Overhead Lines	$	15,083
27	FERC Account	902	Meter Reading Expense		852,824
28			Total	**$**	**867,907**

(1) Inputs for Cost Centers 440021 - ME Meter Reading, 450020 - PN Meter Reading South, 450022 - PN Meter Reading North, 433251 - Penn Power Meter Reading, 490144 - West Penn Meter Reading Excluding Waynesboro, 490201 - West Penn Meter Reading Waynesboro from Budget

Meter Services
Cost Baseline for Smart Meter Benefit
For the Twelve Months Ending April 2016

Line No.		Total Headcount	Salary
	Total Meter Services Costs		
1	*Met-Ed*	37	$ 2,424,995
2	*Penelec*	35	$ 1,942,292
3	*Penn Power*	9	$ 515,189
4	*West Penn Power*	26	$ 1,716,634

	Labor Costs - Original Roles	Headcount	Salary	Severance Costs
5	*Met-Ed*	37	$ 2,113,014	$
6	*Penelec*	35	$ 1,700,276	$
7	*Penn Power*	9	$ 467,411	$
8	*West Penn Power*	26	$ 1,453,666	$

	Uniforms/Supplies	Uniforms/ Supplies Cost
9	*Met-Ed*	$ 112,572
10	*Penelec*	$ 145,714
11	*Penn Power*	$ 4,450
12	*West Penn Power*	$ 117,252

	Fleet Costs	Fleet Costs
13	*Met-Ed*	$ 199,409
14	*Penelec*	$ 96,302
15	*Penn Power*	$ 43,328
16	*West Penn Power*	$ 145,716

	Original Tablet Costs	Replacement Costs	Maintenance Costs
17	*Met-Ed*	$	$
18	*Penelec*	$	$
19	*Penn Power*	$	$
20	*West Penn Power*	$	$

	New Device Costs	Costs
21	*Met-Ed*	$
22	*Penelec*	$
23	*Penn Power*	$
24	*West Penn Power*	$

	Staff Retraining Costs	Cost
25	*Met-Ed*	$
26	*Penelec*	$
27	*Penn Power*	$
28	*West Penn Power*	$

	Labor Costs - New Roles	Headcount	Salary
29	*Met-Ed*		$
30	*Penelec*		$
31	*Penn Power*		$
32	*West Penn Power*		$

(1) Inputs for Cost Centers 440204 Eastern Penn Region Meter Services, 450115 Meter Services, 450116 Meter Services-Northeast L459, 450117 Meter Services-Northwest L459, 450118 Meter Services - South L459, 450119 Meter Services - South L180, 433401 Meter Services - PPCO, 490145 WP Meter Services from Budget

Meter Services
Cost Baseline for Smart Meter Benefit by FERC Accounts
For the Twelve Months Ending April 2016

Line No.				
	Salary			
	Met-Ed			
1	FERC Account	586	Meter Expenses	$ 425,140
2	FERC Account	593	Maintenance of Overhead Lines	48,026
3	FERC Account	597	Maintenance of Meters	1,629,700
4	FERC Account	920	Admin & Gen Salaries	10,148
5			Total	**$ 2,113,014**
	Penelec			
6	FERC Account	586	Meter Expenses	$ 189,879
7	FERC Account	593	Maintenance of Overhead Lines	147,406
8	FERC Account	597	Maintenance of Meters	1,362,991
9			Total	**$ 1,700,276**
	Penn Power			
10	FERC Account	570	Maintenance of Station Equipment	$ 102
11	FERC Account	588	Misc Distribution Expenses	(1,754)
12	FERC Account	593	Maintenance of Overhead Lines	17,780
13	FERC Account	597	Maintenance of Meters	451,157
14	FERC Account	920	Admin & Gen Salaries	126
15			Total	**$ 467,411**
	West Penn Power			
16	FERC Account	586	Meter Expenses	$ 6,209
17	FERC Account	593	Maintenance of Overhead Lines	64,569
18	FERC Account	597	Maintenance of Meters	1,382,888
19			Total	**$ 1,453,666**
	Uniform/Supplies Costs			
	Met-Ed			
20	FERC Account	586	Meter Expenses	$ 56,290
21	FERC Account	597	Maintenance of Meters	56,282
22			Total	**$ 112,572**
	Penelec			
23	FERC Account	586	Meter Expenses	$ 72,857
24	FERC Account	597	Maintenance of Meters	72,857
25			Total	**$ 145,714**
	Penn Power			
26	FERC Account	597	Maintenance of Meters	$ 4,450
27			Total	**$ 4,450**
	West Penn Power			
28	FERC Account	586	Meter Expenses	**$ 117,252**
	Fleet Costs			
	Met-Ed			
29	FERC Account	586	Meter Expenses	$ 40,161
30	FERC Account	593	Maintenance of Overhead Lines	4,540
31	FERC Account	597	Maintenance of Meters	153,765
32	FERC Account	920	Admin & Gen Salaries	943
33			Total	**$ 199,409**
	Penelec			
34	FERC Account	586	Meter Expenses	$ 10,794
35	FERC Account	593	Maintenance of Overhead Lines	8,325
36	FERC Account	597	Maintenance of Meters	77,183
37			Total	**$ 96,302**
	Penn Power			
38	FERC Account	570	Maintenance of Station Equipment	$ 9
39	FERC Account	588	Misc Distribution Expenses	(162)
40	FERC Account	593	Maintenance of Overhead Lines	1,637
41	FERC Account	597	Maintenance of Meters	41,835
42	FERC Account	920	Admin & Gen Salaries	9
43			Total	**$ 43,328**
	West Penn Power			
44	FERC Account	586	Meter Expenses	$ 635
45	FERC Account	593	Maintenance of Overhead Lines	6,472
46	FERC Account	597	Maintenance of Meters	138,609
47			Total	**$ 145,716**

(1) Inputs for Cost Centers 440204 Eastern Penn Region Meter Services, 450115 Meter Services, 450116 Meter Services-Northeast L459, 450117 Meter Services-Northwest L459, 450118 Meter Services - South L459, 450119 Meter Services - South L180, 433401 Meter Services - PPCO, 490145 WP Meter Services from Budget

Back Office
Cost Baseline for Smart Meter Benefit
For the Twelve Months Ending April 2016

Line No.	Total Back Office Costs	Headcount	Salary
1	*Met-Ed*	9	$ 686,873
2	*Penelec*	10	$ 729,613
3	*Penn Power*	3	$ 192,340
4	*West Penn Power*	23	$ 1,353,074

	Labor Costs	Headcount	Salary	Severance Costs
5	*Met-Ed*	9	$ 686,873	$ -
6	*Penelec*	10	$ 729,613	$ -
7	*Penn Power*	3	$ 192,340	$ -
8	*West Penn Power*	23	$ 1,353,074	$ -

(1) Inputs for Cost Centers 509035 – Customer Accounting (OH), 506208 – Customer Accounting (South), 509061 – Customer Accounting (NJ) from Budget

Back Office
Cost Baseline for Smart Meter Benefit by FERC Accounts
For the Twelve Months Ending April 2016

Line No.		FERC Account	Description	Amount
	Salary			
	Met-Ed			
1	FERC Account	903	Cust Rcrd & Collect Exp	$ 686,873
2			Total	**$ 686,873**
	Penelec			
3	FERC Account	903	Cust Rcrd & Collect Exp	$ 729,613
4			Total	**$ 729,613**
	Penn Power			
5	FERC Account	902	Meter Reading Expense	$ 134,636
6	FERC Account	903	Cust Rcrd & Collect Exp	57,704
7			Total	**$ 192,340**
	West Penn Power			
8	FERC Account	902	Meter Reading Expense	$ 448,242
9	FERC Account	923	Outside Svcx Employed	904,832
10			Total	**$ 1,353,074**

(1) Inputs for Cost Centers 509035 – Customer Accounting (OH), 506208 – Customer Accounting (South), 509061 – Customer Accounting (NJ) from Budget

Contact Center
Cost Baseline for Smart Meter Benefit
For the Twelve Months Ending April 2016

Line No.	Total Contact Center Costs	Total Headcount	Salary
1	*Met-Ed*	59	$ 2,741,626
2	*Penelec*	63	$ 2,940,535
3	*Penn Power*	17	$ 778,626
4	*West Penn Power*	70	$ 3,258,602

	Labor Costs	Headcount	Salary	Severance Costs
5	*Met-Ed*	59	$ 2,741,626	$ -
6	*Penelec*	63	$ 2,940,535	$ -
7	*Penn Power*	17	$ 778,626	$ -
8	*West Penn Power*	70	$ 3,258,602	$ -

(1) Inputs for Cost Centers 509057 - FECC Command Center, 509053 - FECC Ops Akron, 509051 - FECC Admin Akron, 509058 - FECC Admin Reading, 509059 - FECC Ops Reading, 509086 - FECC Ops Akron - Toledo, 509321 - FECC Ops Fairmont, 509322 - FECC Admin Fairmont, 501088 - FECC Quality Monitoring, 509351 - Customer Self-Service, from Budget

Contact Center
Cost Baseline for Smart Meter Benefit by FERC Accounts
For the Twelve Months Ending April 2016

Line No.		FERC Account	Description	Amount
	Salary			
	Met-Ed			
1	FERC Account	903	Cust Rcrd & Collect Exp	$ 285,781
2	FERC Account	910	Misc Cust Svc & Info Exp	2,455,845
3			Total	**$ 2,741,626**
	Penelec			
4	FERC Account	903	Cust Rcrd & Collect Exp	$ 320,876
5	FERC Account	910	Misc Cust Svc & Info Exp	2,619,659
6			Total	**$ 2,940,535**
	Penn Power			
7	FERC Account	903	Cust Rcrd & Collect Exp	$ 70,191
8	FERC Account	910	Misc Cust Svc & Info Exp	708,435
9			Total	**$ 778,626**
	West Penn Power			
10	FERC Account	902	Meter Reading Expense	$ 2,859,928
11	FERC Account	903	Cust Rcrd & Collect Exp	252,159
12	FERC Account	910	Misc Cust Svc & Info Exp	146,515
13			Total	**$ 3,258,602**

(1) Inputs for Cost Centers 509057 - FECC Command Center, 509053 - FECC Ops Akron, 509051 - FECC Admin Akron, 509058 - FECC Admin Reading, 509059 - FECC Ops Reading, 509086 - FECC Ops Akron - Toledo, 509321 - FECC Ops Fairmont, 509322 - FECC Admin Fairmont, 501088 - FECC Quality Monitoring, 509351 - Customer Self-Service, from Budget

Revenue Enhancement and Avoided Capital Costs
Cost Baseline for Smart Meter Benefit
For the Twelve Months Ending April 2016

Revenue Enhancement -- Change 1.5 day lag in Cash Working Capital

Line No.		Met-Ed	Penelec	Penn Power	West Penn	Total
1	1.5 day lag for billing difference in CWC	$ 3,336,000	$ 3,206,000	$ 867,000	$ 3,384,000	$ 10,793,000
2	Associated Rev Req	$ 500,000	$ 484,000	$ 130,000	$ 500,000	$ 1,614,000

Avoided Capital Costs -- Material and Supply Inventories at March 31, 2014

		Met-Ed	Penelec	Penn Power	West Penn	Total
3	Total meters in inventory	$ 423,493	$ 493,802	$ 85,054	$ 602,254	$ 1,604,603
4	Smart Meters in inventory	139	130	44	207	520
5	Legacy meters in inventory (Line 1 - Line 2)	$ 423,354	$ 493,672	$ 85,010	$ 602,047	$ 1,604,083
6	Handheld devices in inventory	-	-	-	-	-
7	Total inventory (Line 3 + Line 4)	$ 423,354	$ 493,672	$ 85,010	$ 602,047	$ 1,604,083
8	Revenue requirement	$ 42,697	$ 54,561	$ 6,135	$ 59,352	$ 162,745

Load Research
Cost Baseline for Smart Meter Benefit
For the Twelve Months Ending April 2016

Line No	Description	Met-Ed	Penelec	Penn Power	West Penn	Total
1	Number of load research meters in field	196	284	14	238	732
2	Cost of load research meters	$ 400	$ 400	$ 400	$ 400	$ 1,600
3	Cost of Normal meters	50	50	50	50	200
4	Net Cost of load research Meters (Line 2 - Line 3)	350	350	350	350	1,400
5	Capital Cost of load research Meters (line 1 X line 4)	68,600	99,400	4,900	83,300	256,200
6	Depreciation Reserve per meter	87	87	215	226	616
7	Accumulated Depreciation Reserve (Line 1 X Line 6)	17,081	24,780	3,012	53,887	98,761
8	Net load research Meters in Rate Base (Line 5 - Line 7)	$ 51,519	$ 74,620	$ 1,888	$ 29,413	$ 157,439
9	Carrying Charge	12.91%	12.93%	13.16%	12.76%	
10	Revenue requirement for rate base (Line 8 X Line 9)	$ 6,651	$ 9,648	$ 248	$ 3,753	$ 20,301
11	Depreciation Rate of meters	4.19%	4.30%	2.70%	2.10%	
12	Depreciation expense (Line 5 X Line 11)	2,874	4,274	132	1,749	9,030
13	Revenue requirement (Line 10 + Line 12)	$ 9,525	$ 13,923	$ 381	$ 5,502	$ 29,331

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2014-2428745

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. R-2014-2428743

PENNSYLVANIA POWER COMPANY
DOCKET NO. R-2014-2428744

WEST PENN POWER COMPANY
DOCKET NO. R-2014-2428742

Direct Testimony of Patricia M. Larkin

List of Topics Addressed

Cash Working Capital

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DIRECT TESTIMONY
OF
PATRICIA M. LARKIN

I. INTRODUCTION AND PURPOSE

Q. Please state your name and business address.

A. My name is Patricia M. Larkin and my business address is 2800 Pottsville Pike, Reading, Pennsylvania 19612.

Q. Ms. Larkin, by whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company as a State Regulatory Analyst in the Rates and Regulatory Affairs Department – Pennsylvania.

Q. What are your responsibilities as a State Regulatory Analyst?

A. Generally, the Pennsylvania Rates and Regulatory Affairs Department provides regulatory support for Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power") and West Penn Power Company ("West Penn") (collectively, the "Companies"). I am responsible to the Manager of Rates and Regulatory Affairs for the preparation and coordination of the Companies' accounting and financial data in all their rate-related matters before the Pennsylvania Public Utility Commission ("Commission") and the New York State Public Service Commission, including the preparation of statements and reports addressing, among other things, energy costs, regulatory program cost recovery, quarterly earnings, and other financial matters. Also, I am responsible for the administration of the Companies'

wholesale tariffs, the development of retail electric rates and the promulgation of rules and regulations ensuring uniform tariff administration and interpretation.

Q. What is your educational background?

A. I graduated from Allentown College St. Francis DeSales in 2000 with a Bachelor of Science degree in Accounting and Alvernia College in 2003 with a Master in Business Administration degree. I have over fourteen years of experience with GPU Energy/FirstEnergy Corp. My work experience is more fully described in Appendix A.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying in this proceeding on behalf of Met-Ed, Penelec, Penn Power and West Penn. My testimony equally applies to all of the Companies, unless otherwise stated.

Q. Ms. Larkin, have you prepared exhibits to accompany your testimony?

A. Yes. Met-Ed Exhibit PML-1, Penelec Exhibit PML-1, Penn Power Exhibit PML-1 and West Penn Exhibit PML-1 (collectively, "Exhibits PML-1"), were prepared by me or under my supervision and are described in detail in my testimony.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe the process I used to determine the total Cash Working Capital requirement for each of the Companies as shown on Page 1 of Exhibits PML-1.

II. CASH WORKING CAPITAL - OVERVIEW

Q. Please define "Cash Working Capital" as it pertains to ratemaking.

A. For ratemaking purposes, Cash Working Capital is generally defined as the average amount of capital provided by investors, over and above the investment in plant and other specifically identified rate base items, to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. Cash Working Capital is determined for ratemaking purposes by a Lead/Lag Study.

Q. Please define the terms "lead" and "lag" as used in your testimony and explain how each is calculated.

A. In general, a lead or a lag measures the time that elapses between receipt of a product or service and receipt of compensation by the party providing that product or service. A lead occurs when payment is made in advance of receiving a product or service. A lag occurs when payment for a product or service occurs after the product has been received or service has been rendered. Exhibits PML-1 quantify lead or lag time in days, depict all identified lags as positive figures, and depict all identified leads as negative figures.

Q. What time period was used for the Companies' Lead/Lag Studies?

A. These studies incorporate projected financial data for the twelve months ended April 30, 2016. Fully normalized Electric Revenues, reflecting distribution revenues at proposed rates, were used to calculate revenue lag.

Q. What was the source of the relevant data used to calculate Cash Working Capital?

A. For the most part, I used financial data for the fully projected future test year that underlie the development of the Companies' revenue requirement shown in exhibits accompanying Met-Ed/Penelec/Penn Power/West Penn Statement No. 2, the direct testimony of Richard A. D'Angelo. However, the determination of Cash Working Capital and the development of revenue requirement are interdependent because changes in Cash Working Capital will affect rate base and net income. Performing the Cash Working Capital and revenue requirement calculations on an iterative basis reduces, but does not eliminate, the impact of that interdependence. Appropriate adjustments to the pro forma distribution revenue, federal and state income taxes, and Pennsylvania gross receipts taxes were made in my Cash Working Capital calculations to account for that interdependence.

Q. Have you prepared a summary showing each of the components that comprise the Total Cash Working Capital for each Company?

A. Yes, I have. Page 1 of Exhibits PML-1 shows each component of the total Cash Working Capital requirement. Using Met-Ed's Exhibit PML-1 to illustrate, the Cash Working Capital requirement associated with revenue lag is $152,122,000, as shown at line 3, column 7. The average lag in payment of the Companies' operating expenses reduces the Cash Working Capital requirement. For Met-Ed, this reduction is $37,061,000 as shown at line 11, column 7. On average, taxes

are paid in advance of the service period to which they relate, which adds to Cash Working Capital requirements ($1,304,000 in the case of Met-Ed as shown at line 22, column 7). The Net Cash Working Capital (shown at line 26, column 7) is the sum of those figures – in Met-Ed's case, $116,365,000 (line 27, column 7). Prepayments and Unamortized Cash Pension Contributions are other elements of Cash Working Capital, as shown at lines 28 and 29, which bring the Total Cash Working Capital, in Met-Ed's case, to $147,828,000, as shown at line 30. Column 8 of the summary identifies the page of Exhibits PML-1 where I developed the lead/lag days for the applicable components of Cash Working Capital.

Q. How did you calculate the lag associated with Electric Revenue?

A. Payment for electric service occurs after service is provided, which produces a lag in receipt of revenues. To calculate total revenue lag, Electric Revenue lag was calculated separately for the periods: (1) from billing to cash collection ("Collection Lag"); (2) from meter reading to billing "Billing Lag"); and (3) from the mid-point of the service period to meter reading ("Service Period Lag").

Collection Lag is the period from mailing a customer's bill until payment is received for that bill. This lag was calculated based on the turn-over in accounts receivable. The ratio of accounts receivable to total billed revenues (identified as "Accounts Receivable Turnover" at page 3 of Exhibits PML-1) is divided into 365 days to derive the average number of days accounts receivable are outstanding or, in other words, the average

time between issuing a bill and collecting a bill. That figure, in days, is the Collection Lag, which, in Met-Ed's case, is 48.5 days.

Billing Lag is the period from the reading of a customer's meter until the bill is mailed. Generally, the bill is prepared the same day the meter is read and is mailed the next day. However, there are exceptions. Reading the meters of large industrial customers can take an additional day because there is more work involved given the nature of the service such customers receive. Also, weekends, holidays, and severe weather may add to the time to read and bill customers. Accounting for these exceptions, the Billing Lag is 1.5 days.

Service Period Lag is measured from the mid-period of the service period to the date a meter is read. Because bills are typically issued once per month, or twelve times per year, the Service Period Lag is 15.2 days (365 days per year/12 billing cycles per year/2). This calculation assumes that electric usage is uniform throughout the month.

The overall Electric Revenue lag is the sum of the Collection Lag, Billing Lag and Service Period Lag, as shown on page 3 at line 21 of Exhibits PML-1. In Met-Ed's case, Total Revenue Lag is 65.2 days.

Q. How did you calculate the lead or lag associated with Other Operating Revenue?

A. The calculation of the Other Operating Revenue lag is shown on page 4 of Exhibits PML-1, which lists each of the individual components of Other Operating Revenue and their respective lead or lag. Lag in receipt of Late Payment Charges and Miscellaneous Service Revenues were calculated with overall Electric Revenue lag because each component is billed with Electric Revenue. The footnotes at the bottom of page 4 explain how leads and lags were calculated for other components of Other Operating Revenue. Total Other Operating Revenue lag is the dollar-weighted average lag time calculated by dividing total (Lead)/Lag Dollars (line 11, column 6) by Total Other Operating Revenue in (line 11, column 4).

Q. Please explain the lag associated with the payment of Energy Costs.

A. The lag days associated with Energy Costs are shown on page 5 of Exhibits PML-1. This measures the average lag between the Companies' receipt of generation service from suppliers of default generation until the Companies pay for that service. The period from the midpoint to the end of each monthly service period is 15.2 days, which assumes uniform purchases over any given month. The Companies' Default Service Supplier Master Agreements require payment on the first business day after the 19th of the month, or twenty days after the end of the service period. The lag is, therefore, 35.2 days (15.2 + 20 days).

Q. How was the lag associated with Payroll determined?

A. Payroll is divided into five categories: Bi-weekly Payroll, Weekly Payroll, Payroll-Adjustments, Payroll Taxes, and Incentive Compensation. A weighted average lag time was calculated for each component, as shown on page 7 of Exhibits PML-1. The lags for each component of Payroll vary among the Companies due to: (1) differing payroll periods; (2) variations in the use of direct deposit and paper checks; and (3) the ratio of Weekly Payroll to Bi-weekly Payroll. The total dollar-weighted Payroll lag time is calculated on page 6 of Exhibits PML-1 by dividing total (Lead)/Lag dollar (line 6, column 6) by total Payroll (line 6, column 4).

Q. Please identify the components of Employee Benefits and explain how the leads and lags were calculated for each component.

A. The principal components of Employee Benefits consist of: (1) Medical Insurance; (2) Life Insurance; (3) Savings Plan Match; (4) Worker's Compensation and Long-Term Disability ("LTD") Insurance; and (5) Other Post-Employment Benefits ("OPEB"). The footnotes on page 8 of Exhibits PML-1 describe how the lag was calculated for each category. The total dollar-weighted average lag for Employee Benefits is shown at line 7, column 6, on page 8.

Q. Please explain how you calculated the lag in payment of the Service Company O&M Allocation.

A. The lag associated with the Service Company O&M Allocation is based on the period from the midpoint of the monthly service period to the date the

intercompany accounting transaction closes. Under the Companies' Service Agreement with FirstEnergy Service Company ("Service Company") and accompanying annual Service Requests, the intercompany accounting transactions occur on the last day of the service period, which is the date when the Service Company bills for those transactions. The bills are paid as part of the monthly accounting close on the same day. Therefore, the lag in payment is 15.2 days. This calculation is shown on page 9 of Exhibits PML-1.

Q. How did you calculate the lag for Other O&M-Distribution?

A. Other O&M-Distribution consists of non-labor related expenses incurred in the normal course of business for products and services that are not addressed elsewhere in Exhibits PML-1. The lag was calculated as the sum of: (1) the period from the midpoint to the end of the monthly service period; and (2) the thirty-day "default" payment period incorporated in the Companies' accounts payable system. This calculation is shown on line 4 of page 9 of Exhibits PML-1.

Q. How did you calculate the lag for Other O&M-Riders?

A. The Companies incur expenses for services and functions provided pursuant to its Universal Service Charge ("USC"), Energy Efficiency and Conservation Charge ("EEC"), Smart Meter Technologies Charge ("SMT"), and Default Service Support ("DSS") Riders. Each of these categories and their associated payment terms are shown on page 10 of Exhibits PML-1 and further explained by footnotes on page 11. The categories and dollar amounts for the USC and EEC Riders are based on the Companies' 2015 Universal Service and Energy

Efficiency and Conservation Plans. The categories and dollar amounts associated with the SMT and DSS Riders are based on the Companies' forecast for the twelve months ending April 30, 2016, as adjusted for ratemaking purposes. The lag days for each category consist of the period from the midpoint of the relevant service period to the applicable vendors' payment dates, which were obtained from personnel responsible for administering each of these programs. For any costs that relate to services provided internally, the lag used is the same as the lag for Service Company O&M Allocation discussed previously.

Q. How did you calculate the lag for Uncollectible Accounts expense?

A. Uncollectible Accounts expense is not considered a cash expense and, therefore, was not included in calculating the Cash Working Capital requirement, as explained in footnote (d) on page 9 of Exhibits PML-1.

Q. How did you calculate the leads and lags associated with Taxes?

A. A weighted average lead or lag was calculated based on the required payment dates and percentage of the payment due on those dates for each tax listed on page 12 of Exhibits PML-1. The calculation of each weighted average lead or lag is set forth on page 13 of Exhibits PML-1.

Q. Why did you assign Depreciation, Amortization, Provision for Deferred Income Taxes and Investment Tax Credit a zero lag?

A. These are considered non-cash items by the Commission and, therefore, they were not included in calculating the Cash Working Capital requirement, as shown on page 1, lines 12, 13, 23, and 24 of Exhibits PML-1.

Q. Was any element of the return on invested capital included in the Companies' Lead/Lag Studies?

A. No element of the return on invested capital was included in calculating Cash Working Capital in Exhibits PML-1. A return on invested capital, in any form, becomes the property of the utility's investors when service is rendered. Consequently, even if some portion of that stream of income were available for use as working capital before being paid out as interest or dividends, it would represent the use of investor-supplied capital to cover the on-going costs of providing service to customers and, as such, does not reduce the Companies' Cash Working Capital requirement.

Q. Why are Prepayments included in the Companies' Cash Working Capital?

A. The Companies must pay certain costs before such costs are charged to expense for accounting and ratemaking purposes. Prepayments are cash expenditures that, while made in one period are not charged to expense until a future period. The claim for Prepayments is based on a thirteen-month average of the various prepaid items, including Prepaid Commission Assessments, Prepaid Property and Liability Insurance, Prepaid Edison Electric Institute ("EEI") Dues Assessments,

and Other Prepaid items, which include rating agency fees, financing fees, line of credit fees, and trustee fees. The detailed calculations of Prepayments are shown on page 14 of Exhibits PML-1.

Q. Please explain the basis for including Unamortized Cash Pension Contributions in the Companies' Cash Working Capital claim.

A. In Met-Ed's and Penelec's 2006 base rate cases, the Commission approved the recovery of pension expense calculated on the basis of a ten-year historical average of actual cash contributions. In its Final Order in that case, the Commission stated:

> Fundamentally, we believe that, regarding the recovery of pension expense, the alternative method requested by MEPN [the Companies] in this proceeding is fair to both ratepayers and stockholders. The Companies' normalization methodology will provide a more consistent and less variable expense claim to be included within base rates as compared to the more significant sums contributed in the two years preceding the 2006 test year in this proceeding. Additionally, we should not ignore this significant benefit to current and former employees just because the Companies' did not make a contribution to the pension fund during any given year."[1]

Q. How does recovering a cash contribution to the pension plan over a ten year period create a working capital need?

A. The Companies have made large cash contributions to their pension trust fund over the last ten years. For ratemaking purposes, the Companies recover those cash outlays over ten years. Throughout those ten years, the Companies bear the

[1] *Pa. PUC v. Metropolitan Edison Company, Pennsylvania Electric Company*, Docket Nos. R-00061366, *et. al*, p. 92 (Order entered January 11, 2007).

carrying costs associated with the prior period expenditures that they made but have not recovered in base rates. That unrecovered amount constitutes the Unamortized Cash Pension Contributions that form the basis for the Companies' claim, as shown on page 15 of Exhibits PML-1.

Q. Did you consider the effect of the earnings on the pension trust fund in your Cash Working Capital claim?

A. Yes. The average earnings on the pension trust fund are reflected in the calculation of the amount of cash contributions and, in that way, reduce the cash contribution. Stated another way, earnings on the cash contributions accrue to the benefit of the fund, reduce the Companies' contribution obligations, and, in that way, provide an "upfront" benefit to customers.

Q. Was Pension expense included in the Companies' Cash Working Capital requirement as a component of their Lead/Lag Studies?

A. No, it was not. Pension expense is shown on page 1, line 7, of Exhibits PML-1 at a zero lag. Thus, pension expense is reflected in the Cash Working Capital requirement only once, through the Unamortized Cash Pension Contribution Balance I described above.

Q. How does the methodology used to calculate the Total Cash Working Capital claim for the Companies in this case compare to that employed by Met-Ed and Penelec in their previous base rate proceedings?

A. Except for the inclusion of Unamortized Cash Pension Contributions to reflect the Cash Work Capital requirement associated with pension expense, the Companies are using the same methodology in this case that Met-Ed and Penelec employed in their 2006 base rate cases at Docket Nos. R-00061366 and R-00061367.

III. SUMMARY OF CASH WORKING CAPITAL REQUIREMENTS

Q. Are all of Met-Ed's lead/lag calculations consistent with the general calculations you described above?

A. No. The employees belonging to the International Brotherhood of Electrical Workers Local 777 do not participate in the Company-sponsored medical insurance plan. Therefore, the weighted average lag for Medical Insurance shown on line 1 of page 8 of Met-Ed Exhibit PML-1 was calculated based on the medical insurance lag appropriate to the expenses incurred for Local 777 employees in addition to the balance of Met-Ed's employees who do participate in the Company-sponsored medical insurance plan.

Q. Please summarize your testimony and recommendations regarding Met-Ed.

A. Met-Ed has supported a Total Cash Working Capital requirement of $147,828,000, as shown on page 1, line 30, of Met-Ed Exhibit PML-1.

Q. Are all of Penelec's lead/lag calculations consistent with the general calculations you described above?

A. Yes. The calculations set forth in Penelec Exhibit PML-1 are consistent with the calculations I described above.

Q. Please summarize your testimony and recommendations regarding Penelec.

A. Penelec has supported a Total Cash Working Capital requirement of $124,842,000, as shown on page 1, line 30, of Penelec Exhibit PML-1.

Q. Are all of Penn Power's lead/lag calculations consistent with the general calculations you described above?

A. Yes. The calculations on Penn Power Exhibit PML-1 are consistent with the calculations I described above.

Q. Please summarize your testimony and recommendations regarding Penn Power.

A. Penn Power has supported a Total Cash Working Capital requirement of $27,636,000, as shown on page 1, line 30, of Penn Power Exhibit PML-1.

Q. Are all of West Penn's lead/lag calculations consistent with the general calculations you described above?

A. Yes. The calculations on West Penn Exhibit PML-1 are consistent with the calculations I described above.

Q. Please summarize your testimony and recommendations regarding West Penn.

A. West Penn has supported a Total Cash Working Capital requirement of $117,080,000, as depicted on page 1, line 30, of West Penn Exhibit PML-1.

Q. Ms. Larkin, does this complete your direct testimony?

A. Yes, it does.

Resume: Education and Experience of Patricia M. Larkin

Education:

2000	Bachelor of Science Degree in Accounting – Allentown College of St. Francis de Sales
2003	Master of Business Administration Degree – Alvernia College

Experience:

6/00 - 8/07	Accountant – Property Accounting Services – GPU Energy
8/07 - 9/08	Accountant – Accounting Research – FirstEnergy Service Company
9/08 - 6/12	Accountant – General Accounting Services (Regulatory Accounting focus) – FirstEnergy Service Company
6/12 – Present	Analyst – Rates & Regulatory Affairs – Pennsylvania – FirstEnergy Service Company

Assisted in development and preparation of filings in the following rate-related proceedings:

Pa. P.U.C. Cases: Docket Nos.

P-2013-2391368
P-2013-2391372
P-2013-2391375
P-2013-2391378
P-2011-2273650
P-2011-2273668
P-2011-2273669
P-2011-2273670
R-00061366
R-00061367

P.U.C. Ohio Case: Docket No. 07-551-EL-AIR

Metropolitan Edison Company
Cash Working Capital
Income Statement
For the 12 Months Ending April 30, 2016
($000)

Line No.	Description	Normalized PAPUC Jurisdictional Distribution (1)	PTC (2)	Riders (3)	PAPUC Total (4)	Daily Amount (5) = (4) / 365	(Lead) / Lag Days (6)	Cash Working Capital (7) = (5) * (6)	Supporting Page of Met-Ed Exhibit PML-1 (8)
	Operating revenues								
1	Electric Revenue	$ 400,017	$ 286,330	$ 122,996	$ 809,343	2,217	65.2	$ 144,548	2 and 3
2	Other Operating Revenue	18,593	10,946	-	29,539	81	93.5	7,574	4
3	Total Operating Revenue	$ 418,610	$ 297,276	$ 122,996	$ 838,882			$ 152,122	
	Operating Expenses								
4	Energy Costs	$ -	$ 275,732	$ 2,542	$ 278,274	762	35.2	$ 26,822	5
5	Payroll	29,035	-	-	29,035	80	16.3	1,304	6 and 7
6	Employee Benefits	4,477	-	-	4,477	12	13.0	156	8
7	Pension	11,687	-	-	11,687	32	0.0	-	
8	Service Company Labor Allocation	13,747	-	-	13,747	38	15.2	578	9 through 11
9	Service Company OTL Allocation	17,558	-	-	17,558	48	15.2	730	9 through 11
10	Other O&M	24,629	-	71,845	96,474	264	28.3	7,471	9 through 11
11	Operating Expense Before Tax	$ 101,133	$ 275,732	$ 74,387	$ 451,252			$ 37,061	
	Depreciation and Amortization								
12	Depreciation	$ 72,727	$ -	$ 3,441	$ 76,168	209	0.0	$ -	
13	Amortization	21,656	8,026	31,380	61,062	167	0.0	-	
14	Total Depreciation and Amortization	$ 94,383	$ 8,026	$ 34,821	$ 137,230			$ -	
	Taxes								
15	Federal Income Tax	$ 63,506	$ (1,063)	$ 2,057	$ 64,500	177	37.5	$ 6,638	12 and 13
16	Corportate Net Income Tax - PA	20,138	(337)	652	20,453	56	29.8	1,669	12 and 13
17	Property / Real Estate Tax	102	-	-	102	-	41.5	-	12 and 13
18	PA Gross Receipts Tax	23,601	16,893	7,257	47,751	131	(71.5)	(9,367)	12 and 13
19	PA Sales and Use Tax	113	-	-	113	-	36.0	-	12 and 13
20	Public Utility Realty Tax	1,535	-	-	1,535	4	(61.0)	(244)	12 and 13
21	Capital Stock	116	-	-	116	-	29.8	-	12 and 13
22	Total Taxes	109,111	15,493	9,966	134,570			(1,304)	
23	Provision for Deferred Income Taxes	$ 2,763	$ -	$ 835	$ 3,598	10	0.0	$ -	
24	Investment Tax Credit	$ (283)	$ -	$ -	$ (283)	(1)	0.0	$ -	
25	Total Operating Expenses	$ 307,107	$ 299,251	$ 120,009	$ 726,367			$ 35,757	
26	**Operating Income**	$ 111,503	$ (1,975)	$ 2,987	$ 112,515			$ 116,365	
27	**Net Cash Working Capital**							$ 116,365	
28	**Prepayments**							$ 1,286	14
29	**Unamortized Cash Pension Contributions**							$ 30,177	15
30	**Total Cash Working Capital**							$ 147,828	

Metropolitan Edison Company
Cash Working Capital
Electric Revenue
For the 12 Months Ending April 30, 2016
($000)

Line No.	Description	Normalized PAPUC Jurisdictional Distribution (1)	PTC (2)	Riders (3)	PAPUC Total (4)	(Lead) / Lag Days (5)	
1	Electric Revenue	$ 400,017	$ 286,330	$ 122,996	$ 809,343	65.2	(a)
2	Total Electric Revenue	$ 400,017	$ 286,330	$ 122,996	$ 809,343	65.2	

Footnote

(a) Lag calculated on Page 3.

Metropolitan Edison Company
Cash Working Capital
Revenue Lag (Based On Actuals)
For the 12 Months Ended March 31, 2014
($000)

Line No	Description	Factor	Accounts Rec. Balance	Billed Revenues	A/R Turnover	(Lead) / Lag Days
		(1)	(2)	(3)	(4)	(5) = 365 / (4)
1	Annual Number of Days					365
2	April, 2013		$ -	$ 61,049		
3	May		-	$ 54,615		
4	June		83,230	$ 56,414		
5	July		-	$ 66,495		
6	August		-	$ 67,955		
7	September		79,966	$ 59,196		
8	October		-	$ 53,832		
9	November		-	$ 51,177		
10	December, 2013		101,736	$ 60,451		
11	January, 2014		-	$ 68,732		
12	February		-	67,983		
13	March, 2014		126,615	68,086		
14	Total Accounts Receivable Balance		$ 391,547			
15	Quarterly Average (Line 14 / 4)	4	$ 97,887			
16	Total Billed Revenues			$ 735,985		
17	Accounts Receivable Turnover (Line 16 / Line 15)				7.52	
18	Collection Days Lag (Line 1 / Line 17)					48.5 days
19	Lag from Meter Reading to Billing (a)					1.5 days
20	Lag from Service Period to Meter Reading (b)		365 / 12 / 2 =			15.2 days
21	Total Revenue Lag					**65.2 days**

Footnotes

(a) Lag based on On-demand billing with additional lag stemming from weekends and holidays.

(b) Lag based on a meter being read 12 times annually and service being rendered evenly throughout the meter reading period.

Metropolitan Edison Company
Cash Working Capital
Other Operating Revenue
For the 12 Months Ending April 30, 2016
($000)

Line No.	Description	FERC Account	Normalized PAPUC Jurisdictional Distribution	PTC	Riders	PAPUC Total	(Lead) / Lag Days		(Lead) / Lag Dollars
			(1)	(2)	(3)	(4)	(5)		(6) = (4) * (5)
1	Sales for Resale	447	$ -	$ 12,678	$ -	$ 12,678	35.2	(a)	$ 446,266
2	Late Payment Charges	450	3,229	-	-	3,229	65.2	(b)	210,531
3	Misc. Service Revenues	451	1,903	-	-	1,903	65.2	(b)	124,076
4	Pole Rentals - Telecom	454	4,926	-	-	4,926	399.8	(c)	1,969,415
5	Pole Rentals - Cable	454	2,922	-	-	2,922	(16.0)	(c)	(46,752)
6	Assoc Co's	454	3,915	-	-	3,915	15.2	(d)	59,508
7	Other	454	1,655	-	-	1,655	35.2	(a)	58,256
8	Other Revenue	456	43	308	-	351	35.2	(a)	12,355
9	NITS Contra Revenue	456	-	(2,040)	-	(2,040)	35.2	(a)	(71,808)
10	Wheeling Revenues	456	-	-	-	-	35.2	(a)	-
11	Total Other Operating Revenue		$ 18,593	$ 10,946	$ -	$ 29,539	93.5	(e)	$ 2,761,847

Footnotes

(a) Lag based on service midpoint (15.2) + the PJM settlement date, the first common banking day after the 19th of the month (20).

(b) Lag conservatively based on electric revenue lag, calculated on Page 3.

(c) Lag based on the weighted average of the five largest customers.

(d) Lag based on midpoint of service period (15.2). Intercompany accounting transactions occur on the last day of the service period. Service Company bills and the Company pays on the same day.

(e) Line 11, Column 6 / Line 10 Column 4

Metropolitan Edison Company
Cash Working Capital
Energy Costs
For the 12 Months Ending April 30, 2016
($000)

Line No.	Description	Normalized PAPUC Jurisdictional Distribution (1)	PTC (2)	Riders (3)	PAPUC Total (4)	(Lead) / Lag Days (5)	
1	Energy Costs	$ -	$ 275,732	$ 2,542	$ 278,274	35.2	(a)
2	Total Energy Costs	$ -	$ 275,732	$ 2,542	$ 278,274	35.2	

Footnotes

(a) Lag based on service midpoint (15.2) + Supplier Master Agreement payment terms, the first common banking day after the 19th of the month (20).

Metropolitan Edison Company
Cash Working Capital
Payroll
For the 12 Months Ending April 30, 2016
($000)

Line No.	Description	Normalized PAPUC Jurisdictional Distribution (1)	PTC (2)	Riders (3)	PAPUC Total (4)	(Lead) / Lag Days (5)		(Lead) / Lag Dollars (6) = (4) * (5)
1	Bi-weekly Payroll	$ 6,684	$ -	$ -	$ 6,684	11.2	(a)	$ 74,861
2	Weekly Payroll	17,109	-	-	17,109	6.7	(b)	114,630
3	Payroll - Adjustments	-	-	-	-	7.9	(c)	-
4	Payroll Taxes	4,244	-	-	4,244	9.8	(d)	41,591
5	Incentive Compensation	998	-	-	998	242.5	(e)	242,015
6	Total Payroll	$ 29,035	$ -	$ -	$ 29,035	16.3	(f)	$ 473,097

Metropolitan Edison Company
Cash Working Capital
Payroll Expense Lag Days - Footnotes
For the 12 Months Ending April 30, 2016

Footnotes	Line No.	Description		Payment Weighting Factor	Payment Weighting Ratio	Days Until Payment After Service Period	Midpoint of Service Period	(Lead) / Lag Payment Days	Weighted (Lead) / Lag Days
				(1)	(2)	(3)	(4)	(5) = (3) + (4)	(6) = (5) * (2)
(a)		**BI-WEEKLY PAYROLL (Sunday - Saturday)** - Pay date is Friday after the end of the pay period. Direct deposit amounts are withdrawn from the Company's bank account on Wednesday.							
	1	Direct Deposit			91%	4.0	7.0	11.0	10.0
	2	Paper Check			9%	6.0	7.0	13.0	1.2
	3	Total			100%				11.2
(b)		**WEEKLY PAYROLL (Monday - Sunday)** - Pay date is Friday after the end of the pay period. Direct deposit amounts are withdrawn from the Company's bank account on Wednesday.							
	4	Direct Deposit			91%	3.0	3.5	6.5	5.9
	5	Paper Check			9%	5.0	3.5	8.5	0.8
	6	Total			100%				6.7
(c)		**PAYROLL - ADJUSTMENTS** - weighted on bi-weekly and weekly payroll expense using the total lag days calculated in (a) and (b) above.							
	7	Bi-weekly Payroll weighted lag days	$	6,684	28%			11.2	3.1
	8	Weekly Payroll weighted lag days		17,109	72%			6.7	4.8
	9	Total	$	23,793	100%				7.9
(d)		**PAYROLL TAXES** - ADP withdraws Tax Expense from the Company's bank account on payday; Weighted on bi-weekly and weekly payroll expense using the paper check lag days calculated in (a) and (b) above.							
	10	Bi-weekly Payday			28%			13.0	3.7
	11	Weekly Payday			72%			8.5	6.1
	12	Total			100%				9.8
(e)		**INCENTIVE COMPENSATION** - paid for the entire year in early March of the following year; Assume March 1.							
	13	Payment			100%	60.0	182.5		242.5

(f) Line 6, Column 6 / Line 6, Column 4

Metropolitan Edison Company
Cash Working Capital
Employee Benefits
For the 12 Months Ending April 30, 2016
($000)

Line No.	Description	Normalized PAPUC Jurisdictional Distribution (1)	PTC (2)	Riders (3)	PAPUC Total (4)	(Lead) / Lag Days (5)		(Lead) / Lag Dollars (6) = (4) * (5)
1	Medical Insurance	$ 2,297	$ -	$ -	$ 2,297	6.7	(a)	$ 15,390
2	Life Insurance	36	-	-	36	30.2	(b)	1,087
3	Savings Plan Match	1,120	-	-	1,120	9.8	(c)	10,976
4	Worker's Compensation / LTD	170	-	-	170	13.0	(d)	2,210
5	OPEB - Medical/Health Insurance	222	-	-	222	0.0	(e)	-
6	Other Employee Benefits	632	-	-	632	45.2	(f)	28,566
7	Total Employee Benefits	$ 4,477	$ -	$ -	$ 4,477	13.0	(g)	$ 58,229

Footnotes

(a) Lag based on a bargaining medical premiums being paid on the 1st and 15th of the following month and non-bargaining being sel insured with typical claim processing time of 1.4 months. See the weighting calculation associated with Footnote (c) - Paryoll Adjustments on Page 7.

Non-Bargaining	28%		42.5	42.5	11.9
Bargaining	72%	15.2	(22.5)	(7.3)	(5.2)
Total	100%				6.7

(b) Lag based on premiums being paid on the 15th of the next month for the current month coverage.

(c) See the calculation associated with Footnote (d) - Payroll Taxes on Page 7. The Savings Plan Match is also paid on payday.

(d) Lag based on premiums and claims being paid bi-weekly on a Friday for the prior weeks.

(e) Lag based on non-cash items being assigned a zero lag.

(f) Lag based on Accounts Payable defaulting to a 30 day lag if payment terms are not established + 15.2 midpoint

(g) Line 7, Column 6 / Line 7, Column 4

Metropolitan Edison Company
Cash Working Capital
Service Company O&M Allocation and Other O&M
For the 12 Months Ending April 30, 2016
($000)

Line No.	Description	Normalized PAPUC Jurisdictional Distribution (1)	PTC (2)	Riders (3)	PAPUC Total (4)	(Lead) / Lag Days (5)		(Lead) / Lag Dollars (6) = (4) * (5)
	SERVICE COMPANY O&M ALLOCATION							
1	Service Company Labor Allocation	$ 13,747	$ -	$ -	$ 13,747	15.2	(a)	$ 208,954
2	Service Company OTL Allocation	$ 17,558	$ -	$ -	$ 17,558	15.2	(a)	$ 266,882
3	Total Service Company O&M (Lines 1 + 2)	$ 31,305	$ -	$ -	$ 31,305			$ 475,836
	OTHER O&M							
4	Other O&M - Distribution	$ 19,896	$ -	$ -	$ 19,896	45.2	(b)	$ 899,299
5	Other O&M - Riders	-	-	64,442	64,442	28.4	(c)	1,830,153
6	Uncollectibles	4,733	-	7,403	12,136	0.0	(d)	-
7	Total Other O&M (Lines 4 + 5 + 6)	$ 24,629	$ -	$ 71,845	$ 96,474	28.3	(e)	$ 2,729,452

Footnotes

(a) Lag based on midpoint of service period (15.2). Intercompany accounting transactions occur on the last day of the service period. Service Company bills and the Company pays on the same day.

(b) Accounts Payable defaults to a 30 day lag.

(c) Lag calculated on Page 10

(d) Lag based on non-cash items being assigned a zero lag.

(e) Line 7, Column 6 / Line 7, Column 4

Metropolitan Edison Company
Cash Working Capital
Other O&M - Riders Lag Days
For the 12 Months Ending April 30, 2016
($000)

Line No.	Description	Normalized PAPUC Jurisdictional USC	EEC	SMT	DSS	PAPUC Total	(Lead) / Lag Days		(Lead) / Lag Dollars
		(1)	(2)	(3)	(4)	(5)	(6)		(6) = (4) * (5)
	USC (a)								
1	USC - PCAP - Admin	$ 1,674				$ 1,674	60.2	(c)	$ 100,775
2	USC - PCAP - Bill Subsidy	16,146				16,146	15.2	(d)	245,419
3	USC - Dollar Energy Fund	75				75	182.5	(e)	13,688
4	USC - Gatekeeper	2				2	15.2	(f)	30
5	USC - CARES	4				4	15.2	(f)	61
6	USC - WARM	4,260				4,260	60.2	(c)	256,452
	EEC (a)								
7	EEC - Program Admin		$ 7,420			7,420	25.2	(g)	186,984
8	EEC - Program Admin		2,371			2,371	60.2	(c)	142,734
9	EEC - Marketing		884			884	25.2	(g)	22,277
10	EEC - M&V		832			832	75.2	(h)	62,566
11	EEC - Incentives		13,030			13,030	15.2	(f)	198,056
12	EEC - Labor		441			441	15.2	(f)	6,703
13	EEC - Tracking and Reporting		419			419	25.2	(g)	10,559
14	EEC - Other		152			152	45.2	(i)	6,870
	SMT (b)					-			-
15	SMT - Contractors			$ 2,400		2,400	25.2	(g)	60,480
16	SMT - Contractors			4,209		4,209	45.2	(i)	190,247
17	SMT- Labor and Program Admin			2,075		2,075	15.2	(f)	31,540
	DSS (b)								
18	DSS - Non-Market Based Charges				$ 9,527	9,527	35.2	(j)	335,350
19	DSS - Retail Enhancements	-	-	-	186	186	45.2	(i)	8,407
20	Total	$ 22,161	$ 25,549	$ 8,684	$ 9,713	$ 66,107	28.4		$ 1,879,198

Metropolitan Edison Company
Cash Working Capital
Other O&M - Riders Lag Days - Footnotes
For the 12 Months Ending April 30, 2016

Footnote

(a) Dollar amounts based on the filed 2015 Plan

(b) Dollar amounts based on the 12 months ended 4/30/16, as adjusted

(c) Per interview with internal program manager, billed monthly, net 45 + 15.2 = 60.2 days

(d) Subsidy is applied to a bill monthy, assume midpoint of the service period

(e) Per interview with internal program manager, billed annually, due immediately. 365 days / 2 = 182.5 days

(f) See the calculation associated with Footnote (a) on Page 9

(g) Per interview with internal program manager, billed monthly, net 10 + 15.2 = 25.2 days

(h) Per interview with internal program manager, billed monthly, net 60 + 15.2 = 75.2

(i) See the calculation associated with Footnote (b) on Page 9

(j) See the calculation associated with Footnote (a) on Page 4.

Metropolitan Edison Company
Cash Working Capital
Taxes
For the 12 Months Ending April 30, 2016
($000)

Line No.	Description	Normalized PAPUC Jurisdictional Distribution (1)	PTC (2)	Riders (3)	PAPUC Total (4)	(Lead) / Lag Days (5)	
1	Federal Income Tax	$ 63,506	$ (1,063)	$ 2,057	$ 64,500	37.5	(a)
2	Corportate Net Income Tax - PA ("CNI")	20,138	(337)	652	20,453	29.8	(b)
3	Property / Real Estate Tax	102	-	-	102	41.5	(c)
4	PA Gross Receipts Tax	23,601	16,893	7,257	47,751	(71.5)	(d)
5	PA Sales and Use Tax	113	-	-	113	36.0	(e)
6	Public Utility Realty Tax ("PURTA")	1,535	-	-	1,535	(61.0)	(f)
7	Capital Stock Tax	116	-	-	116	29.8	(b)
8	Total Taxes	$ 109,111	$ 15,493	$ 9,966	$ 134,570		

Metropolitan Edison Company
Cash Working Capital
Taxes Lag Days - Footnotes
For the 12 Months Ending April 30, 2016

Footnote	Line No.	Description	Payment Percentage	Payment Dates	Midpoint of Service Period	(Lead) / Lag Payment Days	Weighted (Lead) / Lag Days
			(1)	(2)	(3)	(4) = (2) - (3)	(5)
(a)		**FEDERAL INCOME TAX**					
	1	First Payment	25%	4/15/13	7/1/13	(77)	(19.3)
	2	Second Payment	25%	6/15/13	7/1/13	(16)	(4.0)
	3	Third Payment	25%	9/15/13	7/1/13	76	19.0
	4	Fourth Payment	25%	12/15/13	7/1/13	167	41.8
	5	Total					37.5
(b)		**CNI AND CAPITAL STOCK TAX**					
	6	First Payment	25%	3/15/13	7/1/13	(108)	(27.0)
	7	Second Payment	25%	6/15/13	7/1/13	(16)	(4.0)
	8	Third Payment	25%	9/15/13	7/1/13	76	19.0
	9	Fourth Payment	25%	12/15/13	7/1/13	167	41.8
	10	Total					29.8
(c)		**PA PROPERTY TAX**					
	11	First Payment	19%	4/30/13	7/1/13	(62)	(11.8)
	12	Second Payment	68%	8/31/13	7/1/13	61	41.5
	13	Third Payment	13%	9/30/13	7/1/13	91	11.8
	14	Total					41.5
(d)		**PA GROSS RECEIPTS TAX**					
	15	First Payment	90%	3/15/13	7/1/13	(108)	(97.2)
	16	Second Payment	10%	3/15/14	7/1/13	257	25.7
	17	Total					(71.5)
(e)		**PA SALES AND USE TAX**					
	18	Payment	100%	8/20/13	7/15/13	36	36.0
		PURTA					
(f)	19	Payment	100%	5/1/13	7/1/13	(61)	(61.0)

Metropolitan Edison Company
Cash Working Capital
Calculation of 13 Month Average Prepayments
For the 12 Months Ended March 31, 2014
($000)

Line No.	Year	Month	Prepaid Commission Assessment	Prepaid Property and Liability Insurance	Prepaid EEI Dues Assessment	Other Prepaid	Total
			(1)	(2)	(3)	(4)	(5)
1	2013	March	$ 649	$ 318	$ 115	$ 97	$ 1,179
2		April	433	274	102	84	893
3		May	216	229	89	70	604
4		June	-	624	77	63	764
5		July	-	618	64	63	745
6		August	-	555	51	56	662
7		September	2,036	510	38	50	2,634
8		October	1,762	659	26	58	2,505
9		November	1,542	608	13	46	2,209
10		December	1,322	549	-	38	1,909
11	2014	January	1,101	491	126	30	1,748
12		February	881	431	114	30	1,456
13		March	661	377	103	23	1,164
14		Total	$ 10,603	$ 6,243	$ 918	$ 708	$ 18,472
15	Thirteen Month Average Balance		$ 816	$ 480	$ 71	$ 54	$ 1,421
16	Eliminate FERC Jurisdictional (a)			$ 107	$ 16	$ 12	135
17	Amount Allocated to Distrtibution (Line 15 - Line 16)						$ 1,286

Footnote

(a) 22.30% of the Thirteen Month Average Balance was allocated to Transmission -FERC Jurisdiction based on the allocation factor of Distribution Plant.

Metropolitan Edison Company
Cash Working Capital
Unamortized Cash Pension Contribution Balance

Line No.	Payment Date	O&M Payment Amount	Amortization End Date	Months Remaining at 4/30/2016	Unamortized Balance
		(1)		(2)	(3) = (1) * ((2)/120)
1	9/16/2004	$ 21,943	9/30/2014	-19	$ -
2	12/23/2005	20,228	12/31/2015	-4	-
3	1/5/2007	6,103	1/31/2017	9	458
4	9/2/2009	62,366	9/30/2019	42	21,828
5	3/30/2011	15,782	3/31/2021	60	7,891
		$ 126,422			$ 30,177

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2014-2428745

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. R-2014-2428743

PENNSYLVANIA POWER COMPANY
DOCKET NO. R-2014-2428744

WEST PENN POWER COMPANY
DOCKET NO. R-2014-2428742

Direct Testimony
of
Kevin M. Siedt

List of Topics Addressed

Sales and Revenues Normalization
Rate Design
Customer Impact Analysis
Proof of Revenues

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DIRECT TESTIMONY
OF
KEVIN M. SIEDT

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Kevin M. Siedt. My business address is 2800 Pottsville Pike, Reading, Pennsylvania 19612.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company as an Analyst in the Rates and Regulatory Affairs Department – Pennsylvania.

Q. What are your responsibilities as an Analyst?

A. Generally, the Rates and Regulatory Affairs Department provides regulatory support for Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power"), and West Penn Power Company ("West Penn") (each of which may be referred to as "Company" and/or collectively the "Companies"). As an Analyst in the Rates and Regulatory Affairs Department, my responsibility is to support the development, preparation, and presentation of the Companies' retail electric rate design and related rules and regulations, and ensure the uniform administration and interpretation in all the Companies' rate-related matters before the Pennsylvania Public Utility Commission ("Commission"). I also am responsible for, among other things, default service plan development and implementation, recovery of non-utility generation costs, regulatory program cost recovery and other financial matters.

Q. What is your educational background and work experience?

A. I obtained a Masters Degree in Business Administration from Moravian College in 1994. I am also a graduate of Rowan University where I received a Bachelor of Science Degree with a major in Accounting and Finance in 1984. My work experience is more fully described in Appendix A.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Met-Ed, Penelec, Penn Power and West Penn. My testimony applies to all of the Companies, unless otherwise stated.

Q. What is the purpose of your direct testimony?

A. My testimony addresses: (i) the annualization and normalization of sales and revenues used in the Companies' cost-of-service studies; (ii) the rate design methodology used to develop the distribution rates proposed in this proceeding; (iii) a customer impact analysis, which compares bills at current and proposed rates; and (iv) a proof of revenue analysis.

Q. Have you prepared and are you sponsoring exhibits to accompany your testimony?

A. Yes. As discussed in more detail later in my testimony, I am sponsoring Exhibits KMS-1 through KMS-7 for each of the Companies, which were prepared by me or under my supervision. The subjects addressed in each of these exhibits are summarized below:

KMS-1 These exhibits consist of Attachments A, B and C, reflecting normalized sales and revenues for the test years ending April 30, 2016, March 31, 2015, and March 31, 2014, respectively

KMS-2 Summary of Present and Proposed Distribution Revenues

KMS-3 Reactive Billing Demand Charge Calculation

KMS-4 TOU Aggregation Agreement (Met-Ed and Penelec Only)

KMS-5 Proof of Revenues Analyses

KMS-6 Customer Impact Analyses

KMS-7 Cost Curves

KMS-8 Responses to the following Commission filing requirements:

52 Pa. Code § 53.52 (a)-(d)
52 Pa. Code § 53.53 - IV-A-1
52 Pa. Code § 53.53 - IV-A-2
52 Pa. Code § 53.53 - IV-A-3
52 Pa. Code § 53.53 - IV-A-4
52 Pa. Code § 53.53 - IV-A-5
52 Pa. Code § 53.53 - IV-C
52 Pa. Code § 53.53 - IV-D-1
52 Pa. Code § 53.53 - IV-D-2
52 Pa. Code § 53.53 - IV-E-2

In addition, I am sponsoring: (1) modifications to Riders A, L, M (all Companies) and P (Met-Ed and Penelec only) to the Companies' proposed tariffs, which are identified as each Companies' Exhibit 1 and, for service to the Pennsylvania State University, West Penn Company Exhibit 2; and (2) all modifications to the rate schedules in the Companies' proposed tariffs. The modifications to the Companies' riders and rate schedules for which I am responsible are discussed further in this testimony.

II. ENERGY SALES AND REVENUE NORMALIZATIONS

Q. What was the basis for developing each Company's claim for energy sales, demand and base rate revenue for the fully projected future test year?

A. The starting point for each Company's claim was the budget forecast of energy sales, demand and base rate revenue for the twelve months ending April 30, 2016. The budget forecast was developed by reviewing current customer consumption data, conducting

appliance saturation surveys and analyzing actual historical customer usage for the past several years to identify patterns and trends. That information was used to develop detailed projections of the actual billing determinants (number of customers, demand (in kW) and energy (in kWh)) for each rate schedule. The actual charges for each component of each rate schedule were applied to the applicable billing determinants (customers, kW or kWh) to project the revenue to be billed under each rate schedule by month for the fully projected future test year. This detailed process assures that revenue under proposed rates can be directly tied in to the billing determinants underlying the Companies' revenues under existing rates that are used to calculate their revenue deficiency in this case.

Q. In developing the Companies' revenue claims in this case, were the budget projections and, specifically, the application of rates to the projected billing determinants reviewed for computational accuracy?

A. Yes. The budget forecasts were found to be very accurate. However, in a few instances either the billing determinants or the rates used in the budget projections did not align precisely with the more detailed and granular information available to the Rates and Regulatory Affairs Department for certain rate schedules. Consequently, I made appropriate adjustments to the budget data. Those adjustments are both few in number and very small in their impact, representing a net increase in total normalized revenue of the Companies of 0.02%, as shown in Exhibits KMS-1, Attachment A, page 3, column 14 and within the associated footnotes. Although these adjustments do not have a material impact on revenues, they were made to assure that billing determinants are properly stated for each rate schedule so that pro forma revenues at existing and proposed rates

can be tied in directly to the budget data that formed the starting point for developing the Companies' revenue claims in this case.

Q. Were any adjustments made to the budget forecast data to present energy sales, demand and base rate revenue on a ratemaking basis?

A. Yes. Adjustments for ratemaking purposes were made to annualize and normalize the budget data. Annualization is the process of adjusting budgeted sales and revenues projected to be billed over a full test year to reflect the level of sales and revenues as of the end of the test year. In that way, pro forma sales and revenues are stated on a basis that properly reflects sales and revenues to be experienced going forward. Normalization is the process of adjusting budgeted sales and revenues to remove outliers and anomalies from the test year data. Thus, unusual events and one-time effects are "normalized" to reflect ongoing conditions.

Q. Have you prepared an exhibit setting forth annualized and normalized sales and revenues?

A. Yes, I have. Annualized and normalized sales and revenues are presented in Attachments A through C of Exhibits KMS-1 for the twelve months ending April 30, 2016, March 31, 2015, and March 31, 2014, respectively. Summaries of each Company's distribution revenues under existing and proposed rates are provided in Exhibits KMS-2. The principal adjustments to the budget forecast data were made to annualize the sales and revenue effect of customers added during the test year and to normalize and annualize sales levels to reflect reductions attributable to measures that have been or will be implemented under the Companies' Commission-approved Energy Efficiency and

Conservation ("EE&C") Plans, which were adopted pursuant to Section 2806.1 of the Pennsylvania Public Utility Code.

Q. Please describe the adjustment made to budget forecast data for the twelve months ending April 30, 2016 to annualize revenues for changes in number of customers.

A. In accordance with the Commission's filing requirements, an adjustment was made to annualize energy usage and demand for the difference between the monthly average number of customers forecasted for the fully projected future test year and the number of customers forecasted for the end of the fully projected future test year. Usage (kWh) and demand (kW) forecasted for the fully projected future test year were divided by the monthly average number of customers at mid-month (for each month) to calculate the average usage and average billed demand per customer. The average usage (in kWh) and average demand (in kW) per customer were multiplied by the difference between the monthly average number of customers and the number of customers forecasted for the end of the test year to determine the additional kWh and kW to be added to the budget forecast to annualize sales and revenue.

The additional revenues attributable to the customer annualization were calculated by multiplying the additional billing determinants (customers, kW or kW) derived from the customer annualization by the applicable customer, demand or energy charges to determine the additional revenue attributable to annualization. This calculation is shown in Exhibits KMS-1, Attachment A, page 3, column 12.

Q. Please describe the adjustments made to budget forecast data for the twelve months ending April 30, 2016 to normalize and annualize revenues for conservation measures implemented or to be implemented pursuant to the Companies' EE&C Plans.

A. The energy sales that were forecasted by rate schedule for the fully projected future test year reflect anticipated usage reductions from energy efficiency measures implemented in accordance with the Companies' Commission-approved EE&C Plans. The forecasted reductions are reflected by month from May 1, 2015 through April 30, 2016. The revenue reductions for the entire fully projected future test year were calculated by annualizing the usage reduction targets that the Companies must achieve by the end (May 30) of the 2016 EE&C plan year. The annualized amount was netted against the monthly savings already included in the fully projected future test year sales forecast to derive the additional energy efficiency normalization adjustment. The same approach was used to annualize and normalize behind-the-meter generation to derive a total energy efficiency normalization adjustment. The revenue effect of the annualization was calculated by multiplying the annualized energy efficiency sales reductions by the average rate per customer by rate schedule.

III. RATE DESIGN

Q. When was each Company's current rate design established?

A. Met-Ed's and Penelec's current distribution base rates were established pursuant to the Commission's Final Order entered January 11, 2007 at Docket Nos. R-0061366 and R-0061367. Penn Power and West Penn concluded base rate cases in 1988 and 1993, respectively. However, the overall structure of each of those Companies' rates was

modified when their rates were functionally unbundled into distribution, generation and transmission components as part of their respective restructuring proceedings. Because of the time that has elapsed since each Companies' last base rate and restructuring cases, the Companies determined that their existing distribution rate designs should be reviewed to ensure that they reflect the current characteristics of electric distribution service. Accordingly, the Companies have taken this opportunity to consolidate and simplify rate designs and make them more uniform across all four Companies.

Q. What considerations, concepts and objectives underlie the rate designs proposed by the Companies?

A. The following general principles were employed in designing the proposed rates:

- Rates must be designed to produce revenues equal to each Company's revenue requirement at the appropriate billing determinants.

- Rates should be designed to properly reflect cost causation and, in that regard, the results of a cost of service study are used as a guide.

- Rates generally should be designed, if practicable, to move revenues for each rate schedule (or in some instances, customer classes consisting of aggregated rate schedules) toward that schedule's cost of service, giving due regard to factors such as gradualism, economic efficiency, relative ease or difficulty of administration, and customer understandability.

In addition to the general principles I just described, the Companies determined that in developing their proposed rates, they should strive to achieve the following objectives:

- There should be a unified distribution rate design for all four Companies. The Companies are managed on a consistent basis with a uniform set of business processes. The rate design should be aligned to conform with the Companies' operations.

- The rate design should give due consideration to the fact that distribution service has now been fully unbundled for ratemaking purposes. For Penn Power and West Penn, this case is the first opportunity to implement a rate design that focuses specifically on unbundled distribution service and does not continue to apply concepts or rate designs that are a legacy of the previously bundled rate environment.

- All else being equal, distribution rates should reflect customer demand rather than energy usage. This is because distribution costs are driven predominantly by investment in fixed assets, which does not vary with a customer's energy usage.

- With the impending implementation of the Companies' Smart Meter Deployment Plan1 and the significant investment in smart meter technology that the Plan requires, the Companies' rate design should incorporate the functionality that smart meters provide to accurately measure demand.

- The number of rate options, which in large part were a legacy of bundled rates that included generation costs, should be reduced to promote better customer

[1] *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company For Approval of Their Smart Meter Deployment Plan*, Docket Nos. M-2013-2341990, M-2013-2341991, M-2013-2341993 and M-2013-2341994 (Opinion and Order entered June 25, 2014).

understanding of the Companies' rates and to allow for more efficient tariff administration.

- Reconcilable adjustment clauses, set forth in riders to the Companies' base rates, should be used to recover certain costs that are volatile in nature and generally not under the Companies' control, consistent with the criteria for adjustment clauses established under Section 1307 of the Public Utility Code. Applying those principles, a Storm Damage Charge Rider is being proposed for all Companies to recover storm damage costs not recovered through distribution base rates.

- A Universal Service Cost Rider is being proposed for West Penn, which is modeled after the Universal Service Cost Riders previously approved by the Commission for the other Companies. Both of these riders are discussed in more detail by Kimberlie L. Bortz in Met-Ed/Penelec/Penn Power/West Penn Statement No. 3.

Q. What role did the results of cost of service studies play in designing the proposed distribution rates?

A. Cost of service studies for each of the Companies were prepared by Hillary E. Stewart, which are described in Met-Ed/Penelec/Penn Power/West Penn Statement No. 5. The results of the cost of service studies were the starting point for designing the proposed distribution rates. However, the final rate designs for the distribution rates that I am recommending also incorporate the rate design principles and objectives that I previously described, as well as my experience in designing utility rates.

Q. How did you design the proposed distribution rates?

A. I began by reviewing the rates of return produced by the various rate schedules under current rates and the fully projected future test year level of revenue requirement. The rate schedules exhibit a range of returns from positive to negative. The divergent class returns provide an indication, based on a snapshot at a specific moment in time, of the general magnitude of interclass subsidies that exist among rate classes under current rates. Based upon each Company's overall retail rate of return, the cost of service studies show that certain rate schedules are producing less than that rate of return, while others are producing rates of return in excess of the applicable Company's overall rate of return level.

Next, I reviewed the revenue that each rate schedule would have to produce to achieve a rate of return equal to the applicable Company's overall rate of return under the proposed distribution rates. This level of revenue shows the magnitude of the rate changes necessary to move each rate schedule to its cost of service as indicated by the cost of service studies.

While movement toward cost of service is an important element in designing rates, it is not the only factor that must be considered. For instance, the impact on customers' bills from implementing a range of potential rate increases must be considered. Establishing rates for each rate schedule that produce a retail rate of return equal to the applicable Company's overall rate of return is the theoretical target of the rate design process. However, the Companies understand that bringing some of the rate schedules to their indicated cost of service would impose potentially disruptive rate increases. The

proposed rate design, therefore, properly applies the principle of gradualism to mitigate customer impact.

Q. Have tables been prepared that show the rates of return under existing and proposed rates by rate schedule for each of the Companies?

A. Yes. Such tables are set forth in Ms. Stewart's direct testimony. Those tables also show the unitized rates of return ("UROR") for each rate schedule. The UROR of a rate class is the class rate of return divided by the Company's overall average rate of return. A class UROR greater than 1.0 indicates that the class revenue exceeds the class cost of service. A class UROR less than 1.0 indicates that the class revenue is less than the class cost of service. URORs are used as a guide to measure the progress that changes in rates will achieve in moving classes toward a UROR of 1.0 or "unity," which is generally accepted as a desirable goal in rate design, subject to those other rate design factors that I previously discussed.

Q. Were any specific criteria used in determining how much progress should be made in moving specific rate schedules toward unity, or cost of service?

A. Yes. In order to implement the concept of gradualism as applied to the guidance provided by the results of the Companies' cost of service studies, two general criteria were developed. The first criterion was that no customer class would experience, on average, an increase of more than 20% of total revenue assuming customers were taking default service. The second criterion was a benchmark calculated by reference to total distribution revenues. Specifically, for each rate schedule, the Companies calculated two percentages, as follows: (1) revenue equal to the rate schedule's cost of service divided

by total-Company distribution revenue under existing rates; and (2) revenue under the rate schedule's existing rates divided by total-Company distribution revenue under existing rates. The average of those two percentages became a target, such that revenue produced by each rate schedule under the proposed rates, expressed as a percentage of total-Company distribution revenue under proposed rates, would approximate the target percentage.

Q. Turning to the design of specific rates, please describe, in general, the changes the Companies propose to their existing Residential rate schedules.

A. There are two principal substantive differences between the Companies' existing Residential rate schedules and the Residential rate design proposed in this case. First, all Time-of-Day/Seasonal rate schedules were eliminated and have been (for Penn Power and West Penn[2]), or are proposed to be (for Met-Ed and Penelec), replaced with Time-of-Use Default Service Riders. While generation costs can and often do differ – sometimes significantly – based on time of use, the same is not true of the cost of providing distribution service. As I previously explained, the cost of providing distribution service is largely determined by fixed costs that do not vary with the amount of usage or the time of day when usage occurs. Time-of-day and seasonal rate schedules in the existing Met-Ed and Penelec tariffs are a vestige of bundled rates that are not applicable to distribution-only service in the current unbundled rate environment. The Time-of-Use Default Service Riders, on the other hand, are designed to recover generation costs associated with default service for residential customers. Because generation costs vary

[2] West Penn's Rider is denominated in its current tariff a "Time-of-Use Rider" not a "Time-of-Use Default Service Rider." West Penn plans to conform the name of its Rider to the names used by the other Companies.

based on time of use, the Riders provide the appropriate vehicle for recognizing time-of-use differences in such costs.

Second, the Companies propose to increase the customer charge more than the usage charge for Residential service. This approach is consistent with the principle of cost causation because it recognizes that most of the cost of providing distribution service is attributable to investment in fixed assets and does not vary based on the level of customer usage. Additionally, recovering an appropriate level of fixed costs through a fixed charge provides a more stable revenue stream, which is also consistent with the fixed nature of the costs being recovered. Stated another way, because the bulk of the cost of providing distribution service does not vary based on usage, reductions in customer use cannot be matched with reductions in the costs – largely fixed – to furnish distribution service.

Although the Companies' cost of service studies indicate that most of the Companies' costs are indeed fixed, the Companies moderated the increase in the customer charge in order to avoid larger increases for lower-usage customers. The impact of this moderating factor on the average bills of Residential customers at various usage levels is shown in each Company's Exhibit KMS-6 – Customer Impact Analyses, which I discuss later in my testimony.

Q. Do the proposed changes to Residential rate schedules you described apply to all of the Companies?

A. Yes, they do. The Companies' objective is to establish a uniform, relatively simple Residential rate design for consistent use by each of the Companies and, in so doing, to

eliminate various outdated elements of the existing Residential rate designs that are legacies of previously bundled rates.

Q. Please describe the proposed rate schedules that will apply to Commercial customers served at secondary voltage.

A. For all of the Companies, there will be three rate schedules that apply to Commercial customers, with the following availability criteria and principal rate components:

- **Rate Schedule GS Small**. This rate schedule, which will be available to customers with usage up to 1500 kWh per month, will have a modified monthly customer charge and an energy charge per kWh of usage.

- **Rate Schedule GS Medium**. This rate schedule, which will be available for customers with billed demand of up to 400 kW for at least two consecutive months, will have a modified customer charge per month, a per-kW demand charge, a reactive billing demand charge, and a relatively low energy charge.

- **Rate Schedule GS Large**. This rate schedule, which will be available for all customers exceeding 400 kW of billed demand, will also have a modified customer charge per month, a per-kW demand charge, a reactive billing demand charge, and a relatively low energy charge.

Q. What is a reactive billing demand charge as proposed for use in Rate Schedules GS Medium and GS Large?

A. A reactive billing demand charge encourages efficient use of power by customers. Reactive power is in effect wasted energy that, as explained below, requires the

Companies to make additional investments in distribution facilities to correct for the adverse effects of customers' poor power factors. The Companies will calculate a "power factor" for each customer to determine whether the reactive billing demand charge will be applied.

Q. What is "power factor?"

A. Power factor is the ratio of the "real" power flowing to a load (measured in kW) to the "apparent" power (measured in Kilovars or "kVA") in the circuit. Real power is the capacity of the circuit for performing work in a particular time. Apparent power is the power, in excess of real power, needed to serve a load with a poor power factor. Thus, a load with a poor power factor draws more current than a load with a high power factor for the same amount of useful power transferred. In summary, power factor measures how efficiently power is being used by comparing the amount of energy supplied to the circuit (kVA) to the actual amount of energy (kW) used to perform work at a particular point in time. To illustrate the concept, consider a horse pulling a railroad car down a railroad track. Because the railroad ties are uneven, the horse must walk at the side of the track and pull the car at an angle from the centerline of track. The power that would be required to move the car down the track if the motive force were applied along the centerline of the track is the real power (i.e., kW). The effort expended by the horse, pulling from one side of the track, is the total (apparent) power (kVA). The angle by which the horse's pull diverges from the centerline determines the power factor. As the angle to the centerline gets smaller (i.e., as the horse walks closer to the center of the track), the force required to pull the car is reduced and the power factor improves.

The Companies propose that the reactive power be assessed at the unit of measurement for reactive power on a per-reactive kilovolt-ampere ("rKVA") basis. This charge will apply to secondary and primary customers with three-phase service.

Q. Why is it appropriate to include a reactive power charge in distribution rates?

A. A reactive power charge is appropriately included in distribution rates for certain rate schedules because the way to correct for the distortion created by customers' poor power factors is to install capacitors on the distribution system. Capacitors are part of the fixed assets that comprise the distribution system and, as such, their cost is properly reflected in distribution rates and, consistent with principles of cost causation, are appropriately reflected in a reactive power charge.

Q. How was the rkVA charge developed?

A. The rkVA charge proposed by the Companies is based on a study of the cost of adding a 1200 KVAR capacitor bank to each Company's system. The rkVA charge is designed to recover a pre-tax weighted average overall rate of return on the Company's investment in the capacitor bank, applicable depreciation and ongoing operation and maintenance expense associated with the capacitors. Exhibits KMS-3 show the calculation of the rkVA charges that will be applied to all commercial and industrial secondary and primary customers.

Customers with a high power factor would not be subject to the rkVA charge. Therefore, each customer can perform an analysis of whether it is more cost-effective to pay the rkVA charge or invest in its own capacitors and avoid the rkVA charge by individually managing its own power factor.

Q. Will a minimum billing demand charge apply to GS customers, and will it be consistent across all the Companies?

A. Yes. The proposed GS rate schedules for all four Companies contain the following provision regarding a minimum billing demand calculation:

> A Customer's demand shall be measured by indicating or recording instruments. Demands shall be integrated over 15-minute intervals. The billing demand in the current month shall be the greatest of: (i) the maximum measured demand established in the month during On-peak hours, adjusted for Power Factor as stated herein, (ii) forty percent (40%) of the maximum measured demand established in the month during Off-peak hours, adjusted for Power Factor as stated herein, (iii) contract demand or (iv) fifty (50%) of the highest billing demand established during the preceding eleven (11) months.

Q. Why are the Companies proposing a minimum per-kW demand charge for Commercial and Industrial customers?

A. In order to provide safe and reliable service to a customer who applies for new service, a Company must assess its current infrastructure and make appropriate investments to existing infrastructure or in new infrastructure. These investments are based on the customer's estimated load. To the extent that the customer makes a change in its operation and reduces its requirements, the Company still needs to recover the investment that it made in its infrastructure to provide service to that customer.Consistent with the principles of cost causation, such costs should be recovered from those customers who are receiving the benefit of that investment. To do otherwise would improperly shift costs to other customers who are already paying for the investment that the Companies made in the infrastructure to serve that customer.

Q. How do the Companies propose to bill customers that do not have a demand meter, but will be served under a rate schedule that includes a demand charge as part of their applicable distribution rates?

A. For those customers that do not have demand meters, the Company is proposing to derive a measured demand based on an hours-use demand factor of 200. The formula for this calculation is: Measured Demand = kWh/200. The hours-use of demand value of 200 reflects the average hours-use for customers that will be charged a kW demand charge. Under the Companies' Smart Meter Deployment Plan, all customers will eventually have meters capable of registering demand. Consequently, it makes sense to develop and implement appropriate rate designs to properly reflect demand costs and to use a measured demand calculation for customers currently without demand meters. When smart meters are installed for customers that do not currently have demand meters, they will benefit from appropriate demand-based rate schedules that leverage the full functionality of smart meters. To do otherwise would require implementing a non-demand-based rate design that would have to be changed in a future base rate case, while my proposed approach allows the Companies to phase customers onto more responsive demand charges as their metering is upgraded.

Q. Do the rate schedules proposed in this case for service to Commercial and Industrial customers contain a change to the minimum charges assessed to such customers under current rates?

A. Yes. The applicable rate schedules for the Companies will apply a minimum charge to such customers equal to the sum of the Customer Charge, the minimum billing demand charge described above, charges under any applicable Riders, and any energy charges

applicable.[3] For instance, if a customer has no energy use in a given month, the customer would still pay a Customer Charge which is a specific dollar amount per month regardless of usage.

Q. Are the Companies proposing additional riders as part of this filing?

A. Yes. As I noted previously, all four Companies are proposing to adopt a Storm Damage Charge Rider to recover storm damage expenses in excess of the amount that is included in their base rates, and West Penn is proposing to adopt a Universal Service Cost Rider modeled after the Universal Service Cost Riders approved by the Commission for the other Companies. Both of these Riders are addressed in more detail by Ms. Bortz in her direct testimony.

In addition, Time-of-Use Default Service Riders ("TOU Riders") are being proposed for Met-Ed and Penelec. Those Riders are included in the proposed Met-Ed and Penelec tariffs. The TOU Riders will be available to all Residential customers who obtain default service from the Companies. The TOU Riders proposed for Met-Ed and Penelec are similar in their general design to the Time-of-Use Default Service Rider for Penn Power and the Time-of-Use Rider for West Penn that were approved by the Commission in its Final Order approving Default Service Plans for the Companies for the period June 1, 2013 through May 31, 2015.[4] There is, however, one small difference. The TOU Riders Met-Ed and Penelec are proposing maintain the same definition of on-peak hours that

[3] A minimum charge calculation would include energy charges for the current month's usage, while the minimum demand charge would be based upon the highest demand recorded over a prior twelve-month period.

[4] *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs*, Docket Nos. P-2011-2273650, P-2011-2273668, P-2011-2273669 and P-2011-2273670 (Final Order entered August 16, 2012), pp. 87-93.

currently exists in their Rate Schedules RT in order to ease the transition of current RT customers applying for service under the proposed TOU Riders.

Under the TOU Riders, qualifying enrolled customers obtain time-of-use default service from Commission-certified EGSs that contract to provide such service under the terms set forth in the Rider. Additionally, the terms of the relationship between the Companies and the EGSs offering time-of-use service is set forth in a TOU Aggregation Agreement, a form of which is being provided as Met-Ed Exhibit No. KMS-4 and Penelec Exhibit No. KMS-4. The form of TOU Aggregation Agreement set forth in those exhibits are identical to the TOU Aggregation Agreements approved by the Commission for use by Penn Power and West Penn.[5]

In the event that no EGSs contract to provide time-of-use service, the time-of-use default service will be available under the terms and conditions of the Companies' Price to Compare Default Service Rate Rider, which applies the same time-of-use on-peak and off-peak factors as set forth in the proposed Met-Ed and Penelec TOU Riders.

The Companies are also proposing to adopt two Riders that relate to non-utility generation – a Partial Service Rider and a Cogeneration and Small Power Production Qualifying Facility Rider.

[5] *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs*, Docket Nos. P-2011-2273650, P-2011-2273668, P-2011-2273669 and P-2011-2273670 (Opinion and Order on Second Compliance Filing entered May 23, 2013), pp 5-10.

Q. Please explain the proposed Partial Service Riders.

A. The Public Utility Regulatory Policies Act ("PURPA") requires electric utilities to provide back-up, maintenance, supplemental and emergency electric service to PURPA "qualifying facilities" ("QFs"). The Companies currently take different approaches to furnishing this service. Met-Ed and Penelec offer this service to QFs under Rate Schedule QF. (Notably, these Companies offer the same service to non-QFs under Rule 18 of their existing General Rules and Regulations, and the terms of that service are the same as under Rate Schedule QF.) Penn Power offers such services for both QFs and non-QFs under a Partial Service Rider. West Penn provides these services to QFs under its Alternative Generation Rider. The Companies propose to consolidate the provision of these services through a single, standardized Partial Service Rider that will apply to all generating facilities (QFs and non-QFs) that are not net-metered customers.

Q. What services will be offered under the proposed Partial Service Riders?

A. Under the Partial Service Riders, the Companies will provide the following four levels of service, as required by, and defined in, PURPA for QFs: Backup Reservation Service, Scheduled Maintenance Service, Supplemental Service, and Emergency Service. Each form of service has its own set of applicable rules. QFs will pay a per-kW charge for contract demand equal to the greater of their measured billing demand or the net generating capability of their generating facility. The proposed Partial Service Riders are set forth as Rider L in the proposed tariffs of each of the Companies.

Q. Please explain the proposed Cogeneration and Small Power Production Qualifying Facility Riders.

A. The Cogeneration and Small Power Production Qualifying Facility Riders will provide the terms under which the Companies will purchase electricity generated by QFs with maximum generating capacity under 500 kW. Any QFs with generating capacity of 500 kW or greater from which the Companies are required by PURPA to purchase energy will not be eligible for the Riders but instead would have to enter into individually negotiated contracts with one of the Companies. Under the Riders, the Companies will pay eligible QFs 75% of the Real Time Location Marginal Price each for each hour at each Company's aggregate zone for net electric energy delivered. The proposed Cogeneration and Small Power Production Qualifying Facility Riders are set forth as Rider M in the proposed tariffs of each of the Companies.

Q. Are the Companies proposing to eliminate any Riders as part of this filing?

A. Yes, they are. The riders proposed to be eliminated are identified and discussed by Ms. Bortz in Met-Ed/Penelec/Penn Power/West Penn Statement No. 3. As she explains, those riders are not applicable for "unbundled" electric service or have been deemed unnecessary or outdated for other reasons.

Q. Are any riders proposed to be modified as part of this filing?

A. Yes. Penn Power proposes to modify its Universal Service Cost Rider so that it will be consistent with the Met-Ed and Penelec Universal Service Cost Riders, as Ms. Bortz explains in her direct testimony. Additionally, as explained by Laura W. Gifford in Met-Ed/Penelec/Penn Power/West Penn Statement No. 7, West Penn is proposing revisions to

its Default Service Support ("DSS") Rider and its Hourly Pricing Default Service ("HPS") Rider to include components for recovery of default service-related uncollectible accounts expense for residential and commercial customers and industrial customers, respectively. The other Companies are revising their DSS and HPS Riders so that default service-related uncollectible accounts expense for industrial customers will be recovered in their HPS Riders rather than their DSS Riders, as they currently are. In addition, Met-Ed and Penelec are proposing to modify their existing Non-Utility Generation Charge Riders to calculate the NUG-C rate on an annual rather than a quarterly basis effective on June 1, 2015. This proposed change is incorporated in the Non-Utility Generation Charge Riders of Met-Ed and Penelec, which are set forth as Rider P in the proposed tariffs of each of those Companies.

Q. Are any changes being proposed with respect to charges imposed under riders that are already in place for all four Companies?

A. Yes, each Company is proposing to set its State Tax Adjustment Surcharge ("STAS") at zero because its base rate revenue requirement was calculated at the applicable state tax rates. Except for Penn Power, the current STAS for the Companies is a credit. In addition, all four Companies propose to reduce their Smart Meter Technology Charge to zero and include the appropriate level of costs as part of their proposed distribution base rate revenue requirement. This proposed change is set forth in the State Tax Adjustment Surcharge Rider set forth as Rider A in the proposed tariffs of each of the Companies.

IV. PROOF OF REVENUE ANALYSIS AND BILL COMPARISONS

Q. What is a proof of revenue analysis?

A. A proof of revenue analysis provides the total billing units for a specified period (May 1, 2015 through April 30, 2016, for the fully projected future test year), including pro forma ratemaking adjustments, summarized by rate components for each rate schedule and multiplied by the applicable unit rates to derive the base rate revenues that proposed rates will produce. Exhibits KMS-5 contain each Company's respective proof of revenue analysis.

Q. Have you prepared an analysis of the rates in the Companies' proposed tariffs showing their impact upon various customer classes?

A. Yes. Exhibits KMS-6 set forth each Company's comparison of bills at current and proposed rates for the Companies' residential, commercial and industrial customers at selected ranges of usage. Each exhibit shows, among other things, the percentage impact on a customer's total electric service bill based on the proposed rates. For example, as shown on page 1 of Met-Ed Exhibit KMS-6, a residential customer of Met-Ed that receives service under Rate Schedule RS and uses 1000 kWh per month would pay $149.13 under the proposed rates, which represents an increase of 16.02% in the customer's total bill.

Q. Please explain what is shown in Exhibit KMS-7 for each Company.

A. Filing Requirement IV-E-2 requires that the Companies provide a comparison showing costs, as defined by the cost of service study, and the proposed base rate revenues and

usage for all rate schedules. Exhibit KMS-7 for each Company depicts that comparison graphically for representative rate schedules.

V. COMPANY-SPECIFIC MODIFICATIONS

A. Met-Ed And Penelec

Q. Please describe the specific changes to the Met-Ed and Penelec rate designs that are being proposed.

A. The following changes are being proposed to the Met-Ed and Penelec rate designs:

1) Rate Schedule RT will be eliminated, and all of the rate schedules applicable to the residential class will be consolidated into one standard Residential rate schedule. As previously explained, the Companies are proposing a Time-of-Use Default Service Rider for Met-Ed and Penelec that, along with similar Riders already in place for Penn Power and West Penn, will provide Residential customers a time-of-use option for default generation supply service. This approach is consistent with the Commission's Final Order in the Retail Markets Investigation which recommends that the Companies move away from Time-of-Use distribution rates and towards a Time-of-Use rider for generation.[6]

2) As explained earlier, an upper limit of 400 kW will be placed on the availability of Rate Schedule GS-Medium. In addition, the eight-hour and twelve-hour time-of-day rates will be eliminated, and a reactive power charge will be added to this rate schedule.

[6] *Investigation of Pennsylvania's Retail Elec. Market Intermediate Work Plan*, Docket No. I-2011-2237952 (Final Order entered March 2, 2012), p. 47.

3) Rate Schedule GS-Large will be available only for secondary voltage customers with loads over 400 kW. In addition, the eight-hour and twelve-hour time-of-day rates will be eliminated and a reactive power charge will be added.

4) The eight-hour and twelve-hour time-of-day provisions in Rate Schedules GP and TP are being eliminated.

5) The voltage discount for customers served at voltages of 115kV or higher will be made consistent across all the Companies.

Q. Why are all of the eight-hour and twelve-hour time-of-day options being eliminated from the Commercial and Industrial rate schedules?

A. They are being eliminated for several reasons. First, in the current rate schedules the time-of-day rate and the standard rate are the same. Second, the time-of-day provisions were established when bundled rates, which included a generation component, provided customers a meaningful incentive to take service on a time-differentiated rate. The time-of-day rate differentials were largely driven by the cost of providing generation service, which exhibits differences based on time of use. However, after unbundling, time-of-use differentials in distribution rates are not justified because distribution service does not exhibit comparable cost differences based on time of use. Customers desiring time-of-use generation service can shop for that service with EGSs or obtain hourly default service for the generation and transmission portion of their electric service.

B. Penn Power

Q. Please describe the specific changes to the Penn Power rate design that are being proposed.

A. The following changes are being proposed to the Penn Power rate design:

1) Rate Schedule RH – Heating Service, as well as the water heating option of Rate Schedule RH, will be eliminated, and all of the rate schedules applicable to the residential class will be consolidated into one standard Residential rate schedule. The rate schedules being eliminated have been grandfathered for existing customers since June 1, 2008. The Company will maintain the existing Time-of-Use provision within Penn Power's PTC Default Service Rider.

2) The Optional Controlled Service ("OCS") for Water Heating as well as the OCS – Add-On Electric Heat Pump or Centralized Resistance Heating Rate are being eliminated. These rates no longer provide an advantage to Residential customers as compared to the standard Rate Schedule RS.

3) Rate Schedule GS currently is available for secondary voltage customers with loads up to 50 kW. The Company proposes to modify the availability of this Rate Schedule to conform to the standardized rate design, and, as such, it will apply to all customers with usage up to 1,500 kWh per month.

4) Rate Schedule GS-Medium will be revised consistent with the changes I previously discussed for Met-Ed and Penelec.

5) The Company proposes to add a new Rate Schedule GS-Large for those secondary voltage customers with demands over 400 kW. This new rate schedule will have the same rate design as Met-Ed's and Penelec's GS-Large, except that the cost allocation differentials will be derived from Penn Power's cost of service study.

6) The Company proposes to eliminate Rate Schedule OH – Commercial and Industrial Optional Heating.

7) The Company proposes to modify the design of Rate Schedule GP to include a Customer Charge and to replace the existing kVA charge with a reactive power charge in addition to a kW demand charge.

8) For Rate Schedule GT, a new Customer Charge is proposed. The balance of the rate design will remain as currently structured.

9) As previously explained, the voltage discount for customers served at 115kV or greater will be made consistent across all the Companies.

C. West Penn

Q. Please describe the specific changes to the West Penn rate design that are being proposed.

A. The following changes are being proposed to the West Penn rate design:

1) The Wind Energy Service Rider that currently applies to all rate schedules will be eliminated. No customers are served on this Rider.

2) The Company is proposing a Universal Service Cost Rider consistent with those of the other three Companies. As I noted earlier, Ms. Bortz addresses this Rider in Met-Ed/Penelec/Penn Power/West Penn Statement No. 4.

3) As previously explained, to be consistent with the other three Companies, West Penn proposes to revise its DSS and HPS Riders to include an uncollectible accounts component, as Ms. Gifford discusses in Met-Ed/Penelec/Penn Power/West Penn Statement No. 7.

4) Rate Schedule 20 currently is available for non-Residential customers with loads of less than 100 kW. The Company proposes to re-map the customers served on this Rate Schedule to include all non-Residential customers that have usage of less than 1,500 kWh per month. The rate design for this rate class will include a new Customer Charge and will replace the demand charge with an energy-only charge.

5) The Company proposes to transition Rate Schedules 22, 23, and 24 to Rate Schedule 20. Rate Schedules 22 and 23 have been grandfathered for an extended period of time and, due to unbundling, no longer provide a benefit to customers. Because of the seasonal aspect of Rate Schedule 24- Fair and Carnival Service, it is not designed for the current unbundled rate environment. Consequently, there is no reason to retain these Rate Schedules.

6) For all Rate Schedules, the Company proposes to eliminate the block rate structures and space heating options. Due to unbundling, block rates and pricing

differentials for space heating are not cost-justified. For that reason, and in order to simplify the tariff, these provisions should be eliminated.

7) The Company proposes to remap Rate Schedule 30 to conform to the structure of the other three Companies. Rate Schedule 30 currently distinguishes between Rate Schedule 30 (Small) and Rate Schedule 30 (Large), with only customers having loads of 500 kW or greater qualifying for the latter. The new structure West Penn is proposing would maintain all secondary voltage customers with loads of 400 kW or less on Rate Schedule 30. Rate Schedule 30 will be revised to include a new Customer Charge and to remove the voltage discount for customers with loads between 1,000 and 15,000 volts and for customers over 15,000 volts. In addition, all block pricing will be eliminated. The Company also proposes to include a reactive power charge in addition to a standard demand charge.

8) For all secondary voltage customers with loads over 400 kW, the Company is proposing a new Rate Schedule 35 consisting of a Customer Charge, a kW Demand Charge, and a reactive power charge.

9) The Company proposes to consolidate Rate Schedules 40 and 41 and to eliminate the weekly demand provision in Rate Schedule 41, which is currently the only difference between these two rate schedules. The rate design will include a Customer Charge, a kW Demand Charge, and a per kWh energy charge. The Company will maintain the existing reactive power charge, but eliminate the block pricing and modify the voltage discounts to be stated on the basis of a percentage of demand.

Finally, I would note that, in compliance with its commitment in the Commission-approved Joint Petition for Partial Settlement at Docket Nos. A-2010-2176520 and A-2010-2176732, West Penn is proposing no change in the design of Rate Schedules 44 and 46 in this case.

VI. MISCELLANEOUS MATTERS

Q. Please describe the provisions of 52 Pa. Code § 69.36.

A. This section of the Commission's regulations is a Statement of Policy expressing the Commission's intent to examine in electric and gas rate proceedings actions taken by utilities to encourage the development of cost effective energy supply alternatives. I am responding only to 52 Pa. Code § 69.36(5), which requires utilities to demonstrate "progressive work regarding the development of a reliable customer data base."

Q. Please address the Companies' efforts to develop a reliable customer data base in accordance with 52 Pa. Code § 69.36(5).

A. The Companies have completed substantial work in this area. The Companies' Customer Care System currently contains data for each customer regarding billing, usage and usage-related revenue, demand and demand-related revenue, rate categories and a "premises" code. The premises code keeps track of all data associated with a location, even if the customer at that location changes its name, moves, etc. More recently, the Companies have developed a "business warehouse" data base that allows the Companies to query customer-specific data. In addition to this data base, the Companies routinely complete residential customer surveys, which produce additional information concerning customers' characteristics, such as appliance usage and air conditioning saturation. Also,

each year the Companies conduct a Large Power Customer contact survey. Throughout the year, Company representatives routinely meet with large customers to discuss their current and long-term needs and other factors related to their electric service. These contacts provide information regarding programs, services, rates and other information which might affect their businesses.

From these data bases, surveys and other contacts with customers, the Companies have amassed a substantial amount of information about customers' end-use applications and their behavior and decision-making processes. This information is routinely factored into the Companies' planning for furnishing service and conducting their operations.

VII. CONCLUSION

Q. Does this complete your direct testimony?

A. Yes, it does.

Resume: Education and Experience of Kevin M. Siedt

Education:

1984	Bachelor of Science Degree- Accounting/Finance, Rowan University, Glassboro, New Jersey
1994	Masters of Business Administration Degree, Moravian College, Bethlehem, PA

Experience:

1984 – 1987	Commercial Credit Analyst – First Fidelity Bank
1987 – 1993	Financial Analyst, Corporate Finance Department – Foster Wheeler Corporation
1993 – 1996	Senior Financial Analyst, Corporate and Project Finance – Foster Wheeler Corporation
1996 – 1997	Manager of Financial Analysis, Corporate and Project Finance - Foster Wheeler Corporation
1997 – 1998	Director of Financial Analysis, Corporate and Project Finance – Foster Wheeler Corporation
1998 – 2001	Financial Consultant, Treasury Department – GPU Corporation
2001 – 2002	Consultant, Market Economics – GPU Corporation
2002 – 2010	Staff Business Analyst, Rates and Regulatory Affairs – FirstEnergy Service Company
2010 – Present	Rate Analyst V, Rates and Regulatory Affairs – FirstEnergy Service Company

Prepared and presented testimony in the following rate-related cases:

Pa. P.U.C. Cases: Docket Nos.	P-2014-2400828
	P-2013-2390445
	P-2013-2391368
	P-2013-2391372
	P-2013-2391375
	P-2013-2391378
	P-00072259
	P-2010-2157862
	M-2011-2250561
	M-2011-2259298
	M-2011-2250682
	P-2012-2292284
	C-2012-2284617
	C-2012-2295306

M-2012-2312766
M-2012-2312767
M-2012-2312769
M-2012-2312772
M-2012-2312633
M-2012-2312770
M-2012-2334387
M-2912-2334392
M-2912-2334395
M-2912-2334398

NJ BPU Cases: Docket Nos. ER05121018
EM02030152
EM03060438
EM04010045
EM05040314
EM12040309

Assisted in development and preparation of the following rate cases:

Pa. P.U.C. Cases: Docket Nos. R-00061366
R-00061367
P-0072305
M-2008-2069887
P-2008-20066692
P-2009-2093053
P-2009-2093054
R-00974008
R-00974009
M-2009-2092222
M-2009-2112952
M-2009-2552956
P-2009-2093053
P-2009-2093054
M-A-2010-2176520
A-2010-2176732
P-2011-2273650
P-2011-2273668
P-2011-2273669
P-2011-2273670
M-2012-2289411

Metropolitan Edison Company
Sales and Distribution Revenue Normalization
Fully Projected Test Year Twelve Months Ending April 2016

Basic Input Factors

Line No.	Rate Group (1)	Number of Customers: End of Period (2)	Number of Customers: Monthly Average (3)	Billed Usage (KWH) (4)	Billed Demand* Units (5)	Billed Revenues** ($) (6)	Incremental Rate** (¢/KWH) (7)	Incremental Rate** ($/Customer) (8)	Incremental Rate** ($/Demand*) (9)	Added Customers (10)	Added Customer Useage (KWH) (11)	Added Customer Demands* (12)	Specific Energy Adjustment (13)	Specific Demand* Adjustment (14)	Added Customer Use Revenue** (15)	Specific Revenue** Adjustment (16)
1	RS	444,589	444,033	4,679,454,105	0	$ 152,150,999	2.328¢	$ 8.110	$ 2.000	556	5,859,684	0	(25,868,009)	13,704	$ 190,523	$ (574,799)
2	RT	47,052	46,916	739,159,950	0	$ 20,521,442	1.939¢	$ 10.998	$ 2.000	136	2,142,680	0	(4,092,794)	285	$ 59,495	$ (78,789)
3	GSV	277	275	12,085,997	0	$ 247,610	2.131¢	$ 9.323	$ 2.000	2	87,898	0	(67,213)	23,835	$ 2,097	$ 46,238
4	TOT RES	491,918	491,224	5,430,700,052	0	$ 172,920,051				694	8,090,262	0	(30,028,016)	37,824	$ 252,115	$ (607,350)
5	GSS	39,555	39,858	212,488,160	0	$ 7,889,755	1.264¢	$ 10.880	N/A	(303)	(1,615,293)	0	845,832	0	$ (59,977)	$ 10,691
6	GSM	24,595	24,208	2,681,121,461	9,362,411	$ 41,888,228	0.050¢	$ 16.466	$ 3.820	387	42,861,798	149,769	10,016,434	34,977	$ 670,017	$ 138,620
7	MS	133	185	42,386,966	0	$ 1,188,564	2.674¢	$ 24.820	N/A	(52)	(11,914,188)	0	(14,235,083)	0	$ (334,073)	$ (380,646)
8	OL	1,095	1,095	6,002,124	0	$ 668,422	0.000¢	$ 50.869	N/A	0	0	0	24,075	0	$ -	$ -
9	BORD	55	4	71,695	0	$ 1,010	1.409¢	$ 11.685	N/A	51	914,124	0	3,954	0	$ 20,031	$ 56
10	TOT COM	65,433	65,350	2,942,070,406	9,362,411	$ 51,635,979				83	30,246,441	149,769	(3,344,788)	34,977	$ 295,998	$ (231,279)
11	GSL	372	382	949,494,440	2,414,784	$ 6,147,172	0.000¢	$ 60.980	$ 2.430	(10)	(24,855,880)	(63,210)	(1,906,006)	(4,847)	$ (160,918)	$ (11,778)
12	GP	466	462	2,809,906,096	6,711,859	$ 12,844,993	0.066¢	$ 235.280	$ 1.443	4	24,328,192	58,112	(5,842,356)	278,092	$ 111,206	$ 397,431
13	TP	21	21	1,644,063,084	3,411,330	$ 2,283,181	0.000¢	$ 882.160	$ 0.604	0	0	0	(3,388,994)	(7,032)	$ -	$ (4,247)
14	QF	4	0	0	713,400	$ 126,456	0.000¢	$ 79.280	$ 0.177	4	0	0	0	0	$ 3,805	$ -
15	TOT IND	863	865	5,403,463,620	13,251,373	$ 21,401,802				(2)	(527,688)	(5,098)	(11,137,356)	266,213	$ (45,907)	$ 381,406
16	STLT	589	589	28,841,545	0	$ 4,643,922	0.001¢	$ 657.035	N/A	0	0	0	0	0	$ -	$ -
17	TOTAL PA	558,803	558,028	13,805,075,623	22,613,784	$ 250,601,754				775	37,809,015	144,671	(44,510,160)	339,014	$ 502,206	$ (457,223)

*Includes billed kW, minimum kW, and standby kW
**Excludes STAS revenue; includes 5.9% GRT

Metropolitan Edison Company
Sales and Distribution Revenue Normalization
Fully Projected Test Year Twelve Months Ending April 2016

Energy Usage and Adjustments

Line No.	Rate Group (1)	Number of Customers: End of Period (2)	Number of Customers: Monthly Average (3)	Added Customers (2)-(3) (4)	Billed Usage (KWH) (5)	Billed Demand* Units (6)	KWH per Customer (5)/(3) (7)	Demand* per Customer (6)/(3) (8)	Added Customer KWH Usage (4)*(7) (9)	Added Customer Demands* (4)*(8) (10)	Specific Energy Adjust (KWH) (11)	Specific Demand* Adjustment (10)*(6)/(5) (12)	Total Energy Adjustment (9)+(11) (13)	Total Demand* Adjustment (10)+(12) (14)	Normalized Energy (KWH) (5)+(13) (15)	Normalized Demands* (6)+(14) (16)
1	RS	444,589	444,033	556	4,679,454,105	0	10,539	0	5,859,684	0	(25,868,009)	13,704	(20,008,325)	13,704	4,659,445,780	13,704
2	RT	47,052	46,916	136	739,159,950	0	15,755	0	2,142,680	0	(4,092,794)	285	(1,950,114)	285	737,209,836	285
3	GSV	277	275	2	12,085,997	0	43,949	0	87,898	0	(67,213)	23,835	20,685	23,835	12,106,682	23,835
4	TOT RES	491,918	491,224	694	5,430,700,052	0			8,090,262	0	(30,028,016)	37,824	(21,937,754)	37,824	5,408,762,298	37,824
5	GSS	39,555	39,858	(303)	212,488,160	0	5,331	0	(1,615,293)	0	845,832	0	(769,461)	0	211,718,699	0
6	GSM	24,595	24,208	387	2,681,121,461	9,362,411	110,754	387	42,861,798	149,769	10,016,434	34,977	52,878,232	184,746	2,733,999,693	9,547,157
7	MS	133	185	(52)	42,386,966	0	229,119	0	(11,914,188)	0	(14,235,083)	0	(26,149,271)	0	16,237,695	0
8	OL	1,095	1,095	0	6,002,124	0	5,481	0	0	0	24,075	0	24,075	0	6,026,199	0
9	BORD	55	4	51	71,695	0	17,924	0	914,124	0	3,954	0	918,078	0	989,773	0
10	TOT COM	65,433	65,350	83	2,942,070,406	9,362,411			30,246,441	149,769	(3,344,788)	34,977	26,901,653	184,746	2,968,972,059	9,547,157
11	GSL	372	382	(10)	949,494,440	2,414,784	2,485,588	6,321	(24,855,880)	(63,210)	(1,906,006)	(4,847)	(26,761,886)	(68,057)	922,732,554	2,346,727
12	GP	466	462	4	2,809,906,096	6,711,859	6,082,048	14,528	24,328,192	58,112	(5,842,356)	278,092	18,485,836	336,204	2,828,391,932	7,048,063
13	TP	21	21	0	1,644,063,084	3,411,330	78,288,718	162,444	0	0	(3,388,994)	(7,032)	(3,388,994)	(7,032)	1,640,674,090	3,404,298
14	QF	4	0	4	0	713,400	0	0	0	0	0	0	0	0	0	713,400
15	TOT IND	863	865	(2)	5,403,463,620	13,251,373			(527,688)	(5,098)	(11,137,356)	266,213	(11,665,044)	261,115	5,391,798,576	13,512,488
16	STLT	589	589	0	28,841,545	0	48,967	0	0	0	0	0	0	0	28,841,545	0
17	TOTAL PA	558,803	558,028	775	13,805,075,623	22,613,784			37,809,015	144,671	(44,510,160)	339,014	(6,701,145)	483,685	13,798,374,478	23,097,469

*Includes billed kW, minimum kW, and standby kW

Metropolitan Edison Company
Sales and Distribution Revenue Normalization
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Revenues and Adjustments

Line No.	Rate Group (1)	Billed Usage (KWH) (2)	Billed Revenues** ($) (3)	Added Customers (4)	Added Customer KWH Usage (5)	Added Customer Demands* (6)	Specific Energy Adjustment (7)	Specific Demand* Adjustment (8)	Incremental Rate** (¢/KWH) (9)	Incremental Rate** ($/Customer) (10)	Incremental Rate** ($/Demand*) (11)	Added Customer Use Revenue** (4)*(10)*12+(5)*(9)/100+(6)*(11) (12)	Specific Revenue** Adjustment (7)*(9)/100+(8)*(11) (13)	Other Revenue Adjustment (14)	Total Revenue** Adjustment (12)+(13)+(14) (15)	Normalized Revenues** (3)+(15) (16)
1	RS	4,679,454,105	$ 152,150,999	556	5,859,684	0	(25,868,009)	13,704	2.328¢	$ 8.110	$ 2.000	$ 190,523	$ (574,799)	$ -	$ (384,276)	$ 151,766,723
2	RT	739,159,950	$ 20,521,442	136	2,142,680	0	(4,092,794)	285	1.939¢	$ 10.998	$ 2.000	$ 59,495	$ (78,789)	$ -	$ (19,294)	$ 20,502,148
3	GSV	12,085,997	$ 247,610	2	87,898	0	(67,213)	23,835	2.131¢	$ 9.323	$ 2.000	$ 2,097	$ 46,238	$ 40,776	$ 89,111	$ 336,721
4	TOT RES	5,430,700,052	$ 172,920,051	694	8,090,262	0	(30,028,016)	37,824				$ 252,115	$ (607,350)	$ 40,776	$ (314,459)	$ 172,605,592
5	GSS	212,488,160	$ 7,889,755	(303)	(1,615,293)	0	845,832	0	1.264¢	$ 10.880	N/A	$ (59,977)	$ 10,691	$ -	$ (49,286)	$ 7,840,469
6	GSM	2,681,121,461	$ 41,888,228	387	42,861,798	149,769	10,016,434	34,977	0.050¢	$ 16.466	$ 3.820	$ 670,017	$ 138,620	$ -	$ 808,637	$ 42,696,865
7	MS	42,386,966	$ 1,188,564	(52)	(11,914,188)	0	(14,235,083)	0	2.674¢	$ 24.820	N/A	$ (334,073)	$ (380,646)	$ -	$ (714,719)	$ 473,845
8	OL	6,002,124	$ 668,422	0	0	0	24,075	0	0.000¢	$ 50.869	N/A	$ -	$ -	$ -	$ -	$ 668,422
9	BORD	71,695	$ 1,010	51	914,124	0	3,954	0	1.409¢	$ 11.685	N/A	$ 20,031	$ 56	$ 561	$ 20,648	$ 21,658
10	TOT COM	2,942,070,406	$ 51,635,979	83	30,246,441	149,769	(3,344,788)	34,977				$ 295,998	$ (231,279)	$ 561	$ 65,280	$ 51,701,259
11	GSL	949,494,440	$ 6,147,172	(10)	(24,855,880)	(63,210)	(1,906,006)	(4,847)	0.000¢	$ 60.980	$ 2.430	$ (160,918)	$ (11,778)	$ -	$ (172,696)	$ 5,974,476
12	GP	2,809,906,096	$ 12,844,993	4	24,328,192	58,112	(5,842,356)	278,092	0.066¢	$ 235.280	$ 1.443	$ 111,206	$ 397,431	$ -	$ 508,637	$ 13,353,630
13	TP	1,644,063,084	$ 2,283,181	0	0	0	(3,388,994)	(7,032)	0.000¢	$ 882.160	$ 0.604	$ -	$ (4,247)	$ -	$ (4,247)	$ 2,278,934
14	QF	0	$ 126,456	4	0	0	0	0	0.000¢	$ 79.280	$ 0.177	$ 3,805	$ -	$ -	$ 3,805	$ 130,261
15	TOT IND	5,403,463,620	$ 21,401,802	(2)	(527,688)	(5,098)	(11,137,356)	266,213				$ (45,907)	$ 381,406	$ -	$ 335,499	$ 21,737,301
16	STLT	28,841,545	$ 4,643,922	0	0	0	0	0	0.001¢	$ 657.035	N/A	$ -	$ -	$ 219	$ 219	$ 4,644,141
17	TOTAL PA	13,805,075,623	$ 250,601,754	775	37,809,015	144,671	(44,510,160)	339,014				$ 502,206	$ (457,223)	$ 41,556	$ 86,539	$ 250,688,293

*Includes billed kW, minimum kW, and standby kW
**Excludes STAS revenue; includes 5.9% GRT

Other Revenue Adjustments

	Amount
1) GS Voluntary Fire Department Rate Schedule Adjustment - Budget forecast assumed that all customers served under this Rate Schedule receive service on the seasonal rate, and revenues projected at the non-summer rate of $0.01946 per kWh. However, there are no customers taking service under this Rate Schedule subject to the seasonal rate provision. Therefore, an adjustment was made to reflect revenues based on the applicable non-seasonal rate of $0.05043 per kWh.	$ 40,776
2) Borderline Adjustment - This adjustment was made to account for revenues associated with an Investment Charge that was not included in the budget forecast. The Investment Charge is 1% of the Company's investment in facilities to deliver and meter service to borderline customers.	561
3) Street Lighting Adjustment - This adjustment was made to account for revenues associated with an Underground Alternative Technology Lighting charge of 0.20 cents per kWh, which was not included in the budget forecast.	219
Total Other Revenue Adjustments	$ 41,556

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Basic Input Factors

Line No.	Rate Group (1)	Number of Customers: End of Period (2)	Number of Customers: Monthly Average (3)	Billed Usage (KWH) (4)	Billed Demand* Units (5)	Billed Revenues** ($) (6)	Incremental Rate** (¢/KWH) (7)	Incremental Rate** ($/Customer) (8)	Incremental Rate** ($/Demand*) (9)	Added Customers (10)	Added Customer Useage (KWH) (11)	Added Customer Demands* (12)	Specific Energy Adjustment (13)	Specific Demand* Adjustment (14)	Added Customer Use Revenue** (15)	Specific Revenue** Adjustment (16)
1	RS	443,870	443,847	4,721,081,215	0	$ 153,101,971	2.328¢	$ 8.110	$ 2.000	23	244,651	0	(65,411,773)	13,688	$ 7,934	$ (1,495,410)
2	RT	47,065	46,306	738,129,065	0	$ 20,412,213	1.937¢	$ 10.998	$ 2.000	759	12,098,460	0	(10,394,053)	289	$ 334,517	$ (200,755)
3	GSV	277	274	12,128,565	0	$ 248,916	2.141¢	$ 9.322	$ 2.000	3	132,795	0	(169,875)	23,922	$ 3,179	$ 44,207
4	TOT RES	491,212	490,427	5,471,338,845	0	$ 173,763,100				785	12,475,906	0	(75,975,701)	37,899	$ 345,630	$ (1,651,958)
5	GSS	39,545	39,756	208,078,820	0	$ 7,820,665	1.264¢	$ 10.880	N/A	(211)	(1,104,374)	0	(2,702,124)	0	$ (41,507)	$ (34,155)
6	GSM	24,407	24,109	2,685,185,036	9,375,747	$ 41,906,947	0.050¢	$ 16.415	$ 3.820	298	33,190,346	115,922	(36,382,306)	(127,035)	$ 518,117	$ (503,465)
7	MS	133	178	38,030,154	0	$ 1,069,995	2.674¢	$ 24.820	N/A	(45)	(9,614,385)	0	(12,430,991)	0	$ (270,491)	$ (332,405)
8	OL	1,095	1,072	6,106,020	0	$ 613,145	0.000¢	$ 47.675	N/A	23	131,008	0	(81,427)	0	$ 13,158	$ -
9	BORD	55	4	71,487	0	$ 1,007	1.409¢	$ 11.685	N/A	51	911,472	0	(12,833)	0	$ 19,994	$ (181)
10	TOT COM	65,235	65,119	2,937,471,517	9,375,747	$ 51,411,759				116	23,514,067	115,922	(51,609,681)	(127,035)	$ 239,271	$ (870,206)
11	GSL	384	379	935,113,829	2,378,477	$ 6,056,928	0.000¢	$ 60.980	$ 2.430	5	12,336,595	31,380	(6,519,154)	(16,582)	$ 79,912	$ (40,294)
12	GP	458	468	2,779,726,688	6,642,248	$ 12,741,249	0.066¢	$ 235.280	$ 1.443	(10)	(59,395,870)	(141,930)	(18,717,872)	247,321	$ (272,240)	$ 344,530
13	TP	21	21	1,646,259,707	3,415,386	$ 2,248,392	0.000¢	$ 882.160	$ 0.593	0	0	0	(11,327,475)	(23,500)	$ -	$ (13,936)
14	QF	4	0	0	713,400	$ 126,456	0.000¢	$ 79.280	$ 0.177	4	0	0	0	0	$ 3,805	$ -
15	TOT IND	867	868	5,361,100,224	13,149,511	$ 21,173,025				(1)	(47,059,275)	(110,550)	(36,564,501)	207,239	$ (188,523)	$ 290,300
16	STLT	589	592	28,901,545	0	$ 4,641,951	0.001¢	$ 653.428	N/A	(3)	(146,460)	0	0	0	$ (1,962)	$ -
17	TOTAL PA	557,903	557,006	13,798,812,131	22,525,258	$ 250,989,835				897	(11,215,762)	5,372	(164,149,883)	118,103	$ 394,416	$ (2,231,864)

*Includes billed kW, minimum kW, and standby kW
**Excludes STAS revenue; includes 5.9% GRT

Metropolitan Edison Company
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Energy Usage and Adjustments

Line No.	Rate Group (1)	Number of Customers End of Period (2)	Number of Customers Monthly Average (3)	Added Customers (2)-(3) (4)	Billed Usage (KWH) (5)	Billed Demand* Units (6)	KWH per Customer (5)/(3) (7)	Demand* per Customer (6)/(3) (8)	Added Customer KWH Usage (4)*(7) (9)	Added Customer Demands* (4)*(8) (10)	Specific Energy Adjust (KWH) (11)	Specific Demand* Adjustment (10)*(6)/(5) (12)	Total Energy Adjustment (9)+(11) (13)	Total Demand* Adjustment (10)+(12) (14)	Normalized Energy (KWH) (5)+(13) (15)	Normalized Demands* (6)+(14) (16)
1	RS	443,870	443,847	23	4,721,081,215	0	10,637	0	244,651	0	(65,411,773)	13,688	(65,167,122)	13,688	4,655,914,093	13,688
2	RT	47,065	46,306	759	738,129,065	0	15,940	0	12,098,460	0	(10,394,053)	289	1,704,407	289	739,833,472	289
3	GSV	277	274	3	12,128,565	0	44,265	0	132,795	0	(169,875)	23,922	(37,080)	23,922	12,091,485	23,922
4	TOT RES	491,212	490,427	785	5,471,338,845	0			12,475,906	0	(75,975,701)	37,899	(63,499,795)	37,899	5,407,839,050	37,899
5	GSS	39,545	39,756	(211)	208,078,820	0	5,234	0	(1,104,374)	0	(2,702,124)	0	(3,806,498)	0	204,272,322	0
6	GSM	24,407	24,109	298	2,685,185,036	9,375,747	111,377	389	33,190,346	115,922	(36,382,306)	(127,035)	(3,191,960)	(11,113)	2,681,993,076	9,364,634
7	MS	133	178	(45)	38,030,154	0	213,653	0	(9,614,385)	0	(12,430,991)	0	(22,045,376)	0	15,984,778	0
8	OL	1,095	1,072	23	6,106,020	0	5,696	0	131,008	0	(81,427)	0	49,581	0	6,155,601	0
9	BORD	55	4	51	71,487	0	17,872	0	911,472	0	(12,833)	0	898,639	0	970,126	0
10	TOT COM	65,235	65,119	116	2,937,471,517	9,375,747			23,514,067	115,922	(51,609,681)	(127,035)	(28,095,614)	(11,113)	2,909,375,903	9,364,634
11	GSL	384	379	5	935,113,829	2,378,477	2,467,319	6,276	12,336,595	31,380	(6,519,154)	(16,582)	5,817,441	14,798	940,931,270	2,393,275
12	GP	458	468	(10)	2,779,726,688	6,642,248	5,939,587	14,193	(59,395,870)	(141,930)	(18,717,872)	247,321	(78,113,742)	105,391	2,701,612,946	6,747,639
13	TP	21	21	0	1,646,259,707	3,415,386	78,393,319	162,637	0	0	(11,327,475)	(23,500)	(11,327,475)	(23,500)	1,634,932,232	3,391,886
14	QF	4	0	4	0	713,400	0	0	0	0	0	0	0	0	0	713,400
15	TOT IND	867	868	(1)	5,361,100,224	13,149,511			(47,059,275)	(110,550)	(36,564,501)	207,239	(83,623,776)	96,689	5,277,476,448	13,246,200
16	STLT	589	592	(3)	28,901,545	0	48,820	0	(146,460)	0	0	0	(146,460)	0	28,755,085	0
17	TOTAL PA	557,903	557,006	897	13,798,812,131	22,525,258			(11,215,762)	5,372	(164,149,883)	118,103	(175,365,645)	123,475	13,623,446,486	22,648,733

*Includes billed kW, minimum kW, and standby kW

Metropolitan Edison Company
Sales and Distribution Revenue Normalization
Future Test Year Twelve Months Ending March 2015

Revenues and Adjustments

Line No.	Rate Group (1)	Billed Usage (KWH) (2)	Billed Revenues** ($) (3)	Added Customers (4)	Added Customer KWH Usage (5)	Added Customer Demands* (6)	Specific Energy Adjustment (7)	Specific Demand* Adjustment (8)	Incremental Rate** (¢/KWH) (9)	Incremental Rate** ($/Customer) (10)	Incremental Rate** ($/Demand*) (11)	Added Customer Use Revenue** (4)*(10)*12+(5)*(9)/100+(6)*(11) (12)	Specific Revenue** Adjustment (7)*(9)/100+(8)*(11) (13)	Other Revenue** Adjustment (14)	Total Revenue** Adjustment (12)+(13)+(14) (15)	Normalized Revenues** (3)+(15) (16)
1	RS	4,721,081,215	$ 153,101,971	23	244,651	0	(65,411,773)	13,688	2.328¢	$ 8.110	$ 2.000	$ 7,934	$ (1,495,410)	$ -	$ (1,487,476)	$ 151,614,495
2	RT	738,129,065	$ 20,412,213	759	12,098,460	0	(10,394,053)	289	1.937¢	$ 10.998	$ 2.000	$ 334,517	$ (200,755)	$ -	$ 133,762	$ 20,545,975
3	GSV	12,128,565	$ 248,916	3	132,795	0	(169,875)	23,922	2.141¢	$ 9.322	$ 2.000	$ 3,179	$ 44,207	$ 41,390	$ 88,776	$ 337,692
4	TOT RES	5,471,338,845	$ 173,763,100	785	12,475,906	0	(75,975,701)	37,899				$ 345,630	$ (1,651,958)	$ 41,390	$ (1,264,938)	$ 172,498,162
5	GSS	208,078,820	$ 7,820,665	(211)	(1,104,374)	0	(2,702,124)	0	1.264¢	$ 10.880	N/A	$ (41,507)	$ (34,155)	$ -	$ (75,662)	$ 7,745,003
6	GSM	2,685,185,036	$ 41,906,947	298	33,190,346	115,922	(36,382,306)	(127,035)	0.050¢	$ 16.415	$ 3.820	$ 518,117	$ (503,465)	$ -	$ 14,652	$ 41,921,599
7	MS	38,030,154	$ 1,069,995	(45)	(9,614,385)	0	(12,430,991)	0	2.674¢	$ 24.820	N/A	$ (270,491)	$ (332,405)	$ -	$ (602,896)	$ 467,099
8	OL	6,106,020	$ 613,145	23	131,008	0	(81,427)	0	0.000¢	$ 47.675	N/A	$ 13,158	$ -	$ -	$ 13,158	$ 626,303
9	BORD	71,487	$ 1,007	51	911,472	0	(12,833)	0	1.409¢	$ 11.685	N/A	$ 19,994	$ (181)	$ 561	$ 20,374	$ 21,381
10	TOT COM	2,937,471,517	$ 51,411,759	116	23,514,067	115,922	(51,609,681)	(127,035)				$ 239,271	$ (870,206)	$ 561	$ (630,374)	$ 50,781,385
11	GSL	935,113,829	$ 6,056,928	5	12,336,595	31,380	(6,519,154)	(16,582)	0.000¢	$ 60.980	$ 2.430	$ 79,912	$ (40,294)	$ -	$ 39,618	$ 6,096,546
12	GP	2,779,726,688	$ 12,741,249	(10)	(59,395,870)	(141,930)	(18,717,872)	247,321	0.066¢	$ 235.280	$ 1.443	$ (272,240)	$ 344,530	$ -	$ 72,290	$ 12,813,539
13	TP	1,646,259,707	$ 2,248,392	0	0	0	(11,327,475)	(23,500)	0.000¢	$ 882.160	$ 0.593	$ -	$ (13,936)	$ -	$ (13,936)	$ 2,234,456
14	QF	0	$ 126,456	4	0	0	0	0	0.000¢	$ 79.280	$ 0.177	$ 3,805	$ -	$ -	$ 3,805	$ 130,261
15	TOT IND	5,361,100,224	$ 21,173,025	(1)	(47,059,275)	(110,550)	(36,564,501)	207,239				$ (188,523)	$ 290,300	$ -	$ 101,777	$ 21,274,802
16	STLT	28,901,545	$ 4,641,951	(3)	(146,460)	0	0	0	0.001¢	$ 653.428	N/A	$ (1,962)	$ -	$ 219	$ (1,743)	$ 4,640,208
17	TOTAL PA	13,798,812,131	$ 250,989,835	897	(11,215,762)	5,372	(164,149,883)	118,103				$ 394,416	$ (2,231,864)	$ 42,170	$ (1,795,278)	$ 249,194,557

*Includes billed kW, minimum kW, and standby kW
**Excludes STAS revenue; includes 5.9% GRT

Metropolitan Edison Company
Sales and Distribution Revenue Normalization
Historic Test Year Twelve Months Ending March 2014

Basic Input Factors

Line No.	Rate Group	Number of Customers: End of Period	Number of Customers: Monthly Average	Billed Usage (KWH)	Billed Demand* Units	Billed Revenues** ($)	Incremental Rate** (¢/KWH)	Incremental Rate** ($/Customer)	Incremental Rate** ($/Demand*)	Added Customers	Added Customer Useage (KWH)	Added Customer Demands*	Specific Energy Adjustment	Specific Demand* Adjustment	Added Customer Use Revenue**	Specific Revenue** Adjustment
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
1	RS	448,405	445,864	4,893,116,389	13,688	$ 157,305,633	2.328¢	$ 8.110	$ 2.000	2,541	27,884,934	0	(311,594,430)	(872)	$ 896,451	$ (7,255,662)
2	RT	41,810	42,440	724,145,726	286	$ 19,702,348	1.947¢	$ 10.998	$ 2.000	(630)	(10,749,690)	0	(45,171,748)	(18)	$ (292,441)	$ (879,530)
3	GSV	269	269	12,065,561	23,663	$ 340,602	2.182¢	$ 9.275	$ 2.000	0	0	0	(763,983)	(1,498)	$ -	$ (19,666)
4	TOT RES	490,484	488,573	5,629,327,676	37,637	$ 177,348,583				1,911	17,135,244	0	(357,530,161)	(2,388)	$ 604,010	$ (8,154,858)
5	GSS	40,141	40,047	188,742,522	0	$ 7,665,339	1.264¢	$ 10.880	N/A	94	443,022	0	(8,153,062)	0	$ 17,872	$ (103,055)
6	GSM	23,929	23,919	2,724,898,948	9,460,766	$ 42,236,005	0.050¢	$ 16.711	$ 3.820	10	1,139,220	3,960	(117,480,214)	(407,888)	$ 17,702	$ (1,616,872)
7	MS	133	136	18,352,019	0	$ 531,331	2.674¢	$ 24.820	N/A	(3)	(404,823)	0	(773,445)	0	$ (11,718)	$ (20,682)
8	OL	1,062	1,081	6,244,230	0	$ 540,059	0.000¢	$ 41.633	N/A	(19)	(109,744)	0	(264,369)	0	$ (9,492)	$ -
9	BORD	55	55	896,876	0	$ 20,349	1.409¢	$ 11.703	N/A	0	0	0	(38,651)	0	$ -	$ (545)
10	TOT COM	65,320	65,238	2,939,134,595	9,460,766	$ 50,993,083				82	1,067,675	3,960	(126,709,741)	(407,888)	$ 14,364	$ (1,741,154)
11	GSL	347	347	895,465,664	2,311,697	$ 5,871,242	0.000¢	$ 60.980	$ 2.430	0	0	0	(5,540,006)	(14,302)	$ -	$ (34,754)
12	GP	497	495	2,734,432,588	6,889,032	$ 13,160,528	0.066¢	$ 235.280	$ 1.443	2	11,048,212	27,834	(16,985,552)	(42,793)	$ 53,103	$ (72,961)
13	TP	20	20	1,707,486,917	3,591,870	$ 2,348,846	0.000¢	$ 882.160	$ 0.624	0	0	0	(10,563,763)	(22,222)	$ -	$ (13,867)
14	QF	4	5	0	741,100	$ 134,578	0.000¢	$ 79.280	$ 0.169	(1)	0	(148,220)	0	0	$ (26,001)	$ -
15	TOT IND	868	867	5,337,385,169	13,533,699	$ 21,515,194				1	11,048,212	(120,386)	(33,089,321)	(79,317)	$ 27,102	$ (121,582)
16	STLT	594	590	28,927,693	0	$ 4,642,621	0.001¢	$ 655.336	N/A	4	196,120	0	0	0	$ 31,458	$ -
17	TOTAL PA	557,266	555,268	13,934,775,133	23,032,102	$ 254,499,481				1,998	29,447,251	(116,426)	(517,329,223)	(489,593)	$ 676,934	$ (10,017,594)

*Includes billed kW, minimum kW, and standby kW
**Excludes STAS revenue; includes 5.9% GRT

Metropolitan Edison Company
Sales and Distribution Revenue Normalization
Historic Test Year Twelve Months Ending March 2014

Energy Usage and Adjustments

Line No.	Rate Group	Number of Customers: End of Period	Number of Customers: Monthly Average	Added Customers	Billed Usage	Billed Demand*	KWH per Customer	Demand* per Customer	Added Customer KWH Usage	Added Customer Demands*	Specific Energy Adjust (KWH)	Specific Demand* Adjustment	Total Energy Adjustment	Total Demand* Adjustment	Normalized Energy (KWH)	Normalized Demands*
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
					(2)-(3)			(5)/(3)	(6)/(3)	(4)*(7)	(4)*(8)		(10)*(6)/(5)	(9)+(11)	(10)+(12)	(5)+(13)	(6)+(14)
1	RS	448,405	445,864	2,541	4,893,116,389	13,688	10,974	0	27,884,934	0	(311,594,430)	(872)	(283,709,496)	(872)	4,609,406,893	12,816
2	RT	41,810	42,440	(630)	724,145,726	286	17,063	0	(10,749,690)	0	(45,171,748)	(18)	(55,921,438)	(18)	668,224,288	268
3	GSV	269	269	0	12,065,561	23,663	44,853	88	0	0	(763,983)	(1,498)	(763,983)	(1,498)	11,301,578	22,165
4	TOT RES	490,484	488,573	1,911	5,629,327,676	37,637			17,135,244	0	(357,530,161)	(2,388)	(340,394,917)	(2,388)	5,288,932,759	35,249
5	GSS	40,141	40,047	94	188,742,522	0	4,713	0	443,022	0	(8,153,062)	0	(7,710,040)	0	181,032,482	0
6	GSM	23,929	23,919	10	2,724,898,948	9,460,766	113,922	396	1,139,220	3,960	(117,480,214)	(407,888)	(116,340,994)	(403,928)	2,608,557,954	9,056,838
7	MS	133	136	(3)	18,352,019	0	134,941	0	(404,823)	0	(773,445)	0	(1,178,268)	0	17,173,751	0
8	OL	1,062	1,081	(19)	6,244,230	0	5,776	0	(109,744)	0	(264,369)	0	(374,113)	0	5,870,117	0
9	BORD	55	55	0	896,876	0	16,307	0	0	0	(38,651)	0	(38,651)	0	858,225	0
10	TOT COM	65,320	65,238	82	2,939,134,595	9,460,766			1,067,675	3,960	(126,709,741)	(407,888)	(125,642,066)	(403,928)	2,813,492,529	9,056,838
11	GSL	347	347	0	895,465,664	2,311,697	2,580,593	6,662	0	0	(5,540,006)	(14,302)	(5,540,006)	(14,302)	889,925,658	2,297,395
12	GP	497	495	2	2,734,432,588	6,889,032	5,524,106	13,917	11,048,212	27,834	(16,985,552)	(42,793)	(5,937,340)	(14,959)	2,728,495,248	6,874,073
13	TP	20	20	0	1,707,486,917	3,591,870	85,374,346	179,594	0	0	(10,563,763)	(22,222)	(10,563,763)	(22,222)	1,696,923,154	3,569,648
14	QF	4	5	(1)	0	741,100	0	148,220	0	(148,220)	0	0	0	(148,220)	0	592,880
15	TOT IND	868	867	1	5,337,385,169	13,533,699			11,048,212	(120,386)	(33,089,321)	(79,317)	(22,041,109)	(199,703)	5,315,344,060	13,333,996
16	STLT	594	590	4	28,927,693	0	49,030	0	196,120	0	0	0	196,120	0	29,123,813	0
17	TOTAL PA	557,266	555,268	1,998	13,934,775,133	23,032,102			29,447,251	(116,426)	(517,329,223)	(489,593)	(487,881,972)	(606,019)	13,446,893,161	22,426,083

*Includes billed kW, minimum kW, and standby kW

Metropolitan Edison Company
Sales and Distribution Revenue Normalization
Historic Test Year Twelve Months Ending March 2014

Revenues and Adjustments

Line No.	Rate Group (1)	Billed Usage (KWH) (2)	Billed Revenues** ($) (3)	Added Customers (4)	Added Customer KWH Usage (5)	Added Customer Demands* (6)	Specific Energy Adjustment (7)	Specific Demand* Adjustment (8)	Incremental Rate** (¢/KWH) (9)	Incremental Rate** ($/Customer) (10)	Incremental Rate** ($/Demand*) (11)	Added Customer Use Revenue** (4)*(10)*12+(5)*(9)/100+(6)*(11) (12)	Specific Revenue** Adjustment (7)*(9)/100+(8)*(11) (13)	Total Revenue** Adjustment (12)+(13) (14)	Normalized Revenues** (3)+(14) (15)
1	RS	4,893,116,389	$ 157,305,633	2,541	27,884,934	0	(311,594,430)	(872)	2.328¢	$ 8.110	$ 2.000	$ 896,451	$ (7,255,662)	$ (6,359,211)	$ 150,946,422
2	RT	724,145,726	$ 19,702,348	(630)	(10,749,690)	0	(45,171,748)	(18)	1.947¢	$ 10.998	$ 2.000	$ (292,441)	$ (879,530)	$ (1,171,971)	$ 18,530,377
3	GSV	12,065,561	$ 340,602	0	0	0	(763,983)	(1,498)	2.182¢	$ 9.275	$ 2.000	$ -	$ (19,666)	$ (19,666)	$ 320,936
4	TOT RES	5,629,327,676	$ 177,348,583	1,911	17,135,244	0	(357,530,161)	(2,388)				$ 604,010	$ (8,154,858)	$ (7,550,848)	$ 169,797,735
5	GSS	188,742,522	$ 7,665,339	94	443,022	0	(8,153,062)	0	1.264¢	$ 10.880	N/A	$ 17,872	$ (103,055)	$ (85,183)	$ 7,580,156
6	GSM	2,724,898,948	$ 42,236,005	10	1,139,220	3,960	(117,480,214)	(407,888)	0.050¢	$ 16.711	$ 3.820	$ 17,702	$ (1,616,872)	$ (1,599,170)	$ 40,636,835
7	MS	18,352,019	$ 531,331	(3)	(404,823)	0	(773,445)	0	2.674¢	$ 24.820	N/A	$ (11,718)	$ (20,682)	$ (32,400)	$ 498,931
8	OL	6,244,230	$ 540,059	(19)	(109,744)	0	(264,369)	0	0.000¢	$ 41.633	N/A	$ (9,492)	$ -	$ (9,492)	$ 530,567
9	BORD	896,876	$ 20,349	0	0	0	(38,651)	0	1.409¢	$ 11.703	N/A	$ -	$ (545)	$ (545)	$ 19,804
10	TOT COM	2,939,134,595	$ 50,993,083	82	1,067,675	3,960	(126,709,741)	(407,888)				$ 14,364	$ (1,741,154)	$ (1,726,790)	$ 49,266,293
11	GSL	895,465,664	$ 5,871,242	0	0	0	(5,540,006)	(14,302)	0.000¢	$ 60.980	$ 2.430	$ -	$ (34,754)	$ (34,754)	$ 5,836,488
12	GP	2,734,432,588	$ 13,160,528	2	11,048,212	27,834	(16,985,552)	(42,793)	0.066¢	$ 235.280	$ 1.443	$ 53,103	$ (72,961)	$ (19,858)	$ 13,140,670
13	TP	1,707,486,917	$ 2,348,846	0	0	0	(10,563,763)	(22,222)	0.000¢	$ 882.160	$ 0.624	$ -	$ (13,867)	$ (13,867)	$ 2,334,979
14	QF	0	$ 134,578	(1)	0	(148,220)	0	0	0.000¢	$ 79.280	$ 0.169	$ (26,001)	$ -	$ (26,001)	$ 108,577
15	TOT IND	5,337,385,169	$ 21,515,194	1	11,048,212	(120,386)	(33,089,321)	(79,317)				$ 27,102	$ (121,582)	$ (94,480)	$ 21,420,714
16	STLT	28,927,693	$ 4,642,621	4	196,120	0	0	0	0.001¢	$ 655.336	N/A	$ 31,458	$ -	$ 31,458	$ 4,674,079
17	TOTAL PA	13,934,775,133	$ 254,499,481	1,998	29,447,251	(116,426)	(517,329,223)	(489,593)				$ 676,934	$ (10,017,594)	$ (9,340,660)	$ 245,158,821

*Includes billed kW, minimum kW, and standby kW
**Excludes STAS revenue; includes 5.9% GRT

Met-Ed Exhibit KMS-2
Witness: K.M. Siedt

Metropolitan Edison Company
Summary of Distribution of Revenues
Tariff Pa. PUC No. 51 as Compared to Tariff Pa. PUC No. 52

					Present Rates							Proposed Rates					
Line No.	Rate Group (1)	End of Period Customers (2)	Normalized Sales (MWH) (3)	Normalized Demand (KW) (4)	Normalized Base Revenues (5)	Smart Meter Charges (6)	Subtotal Base Dist. Rev. plus Rider Changes (7)	Other Rider Charges (8)	Total Present Rates (9)	Base Rev Percent Increase (10)	Base Revenue Increase (11)	Base Revenues After Increase (12)	Smart Meter Charges (13)	Subtotal Base Dist. Rev. plus Rider Changes (14)	Specific Other Rider Charges (15)	Total Revenue After Increase (16)	Net Overall Increase (17)
1	RS	444,589	4,659,446	13,704	$ 151,766,723	$ 12,468,706	$ 164,235,429	$ 443,309,277	$ 607,544,706	59.59%	$ 97,872,093	$ 262,107,522	$ -	$ 262,107,522	$ 443,309,277	$ 705,416,799	16.11%
2	RT	47,052	737,210	285	$ 20,502,148	$ 1,316,102	$ 21,818,250	$ 69,927,999	$ 91,746,249	73.03%	$ 15,933,893	$ 37,752,143	$ -	$ 37,752,143	$ 69,927,999	$ 107,680,142	17.37%
3	GSV	277	12,107	23,835	$ 336,721	$ 7,736	$ 344,457	$ 1,123,523	$ 1,467,980	70.87%	$ 244,126	$ 588,583	$ -	$ 588,583	$ 1,123,523	$ 1,712,106	16.63%
4	TOT RES	491,918	5,408,763	37,824	$ 172,605,592	$ 13,792,544	$ 186,398,136	$ 514,360,799	$ 700,758,935	16.28%	$ 114,050,112	$ 300,448,248	$ -	$ 300,448,248	$ 514,360,799	$ 814,809,047	16.28%
5	GSS	39,555	211,719	0	$ 7,840,469	$ 1,131,598	$ 8,972,067	$ 18,072,777	$ 27,044,844	60.18%	$ 5,399,233	$ 14,371,300	$ -	$ 14,371,300	$ 18,072,777	$ 32,444,077	19.96%
6	GSM	24,595	2,734,000	9,547,157	$ 42,696,865	$ 703,619	$ 43,400,484	$ 233,380,266	$ 276,780,750	34.26%	$ 14,867,179	$ 58,267,663	$ -	$ 58,267,663	$ 233,380,266	$ 291,647,929	5.37%
7	MS	133	16,238	0	$ 473,845	$ 5,298	$ 479,143	$ 1,477,065	$ 1,956,208	62.18%	$ 297,917	$ 777,060	$ -	$ 777,060	$ 1,477,065	$ 2,254,125	15.23%
8	OL	1,095	6,026	0	$ 668,422	$ -	$ 668,422	$ 503,187	$ 1,171,609	34.05%	$ 227,618	$ 896,040	$ -	$ 896,040	$ 503,187	$ 1,399,227	19.43%
9	BORD	55	990	0	$ 21,658	$ -	$ 21,658	$ 79,869	$ 101,527	59.75%	$ 12,940	$ 34,598	$ -	$ 34,598	$ 79,869	$ 114,467	12.75%
10	TOT COM	65,433	2,968,973	9,547,157	$ 51,701,259	$ 1,840,515	$ 53,541,774	$ 253,513,164	$ 307,054,938	38.86%	$ 20,804,887	$ 74,346,661	$ -	$ 74,346,661	$ 253,513,164	$ 327,859,825	6.78%
11	GSL	372	922,733	2,346,727	$ 5,974,476	$ 10,720	$ 5,985,196	$ 53,949,267	$ 59,934,463	53.98%	$ 3,230,917	$ 9,216,113	$ -	$ 9,216,113	$ 53,949,267	$ 63,165,380	5.39%
12	GP	466	2,828,392	7,048,063	$ 13,353,630	$ 12,984	$ 13,366,614	$ 158,303,323	$ 171,669,937	93.13%	$ 12,448,198	$ 25,814,812	$ -	$ 25,814,812	$ 158,303,323	$ 184,118,135	7.25%
13	TP	21	1,640,674	3,404,298	$ 2,278,934	$ 589	$ 2,279,523	$ 75,365,413	$ 77,644,936	61.27%	$ 1,396,602	$ 3,676,125	$ -	$ 3,676,125	$ 75,365,413	$ 79,041,538	1.80%
14	QF	4	0	713,400	$ 130,261	$ -	$ 130,261	$ -	$ 130,261	223.16%	$ 290,694	$ 420,955	$ -	$ 420,955	$ -	$ 420,955	223.16%
15	TOT IND	863	5,391,799	13,512,488	$ 21,737,301	$ 24,293	$ 21,761,594	$ 287,618,003	$ 309,379,597	79.80%	$ 17,366,411	$ 39,128,005	$ -	$ 39,128,005	$ 287,618,003	$ 326,746,008	5.61%
16	STLT	589	28,842	0	$ 4,644,141	$ -	$ 4,644,141	$ 2,423,877	$ 7,068,018	9.06%	$ 420,972	$ 5,065,113	$ -	$ 5,065,113	$ 2,423,877	$ 7,488,990	5.96%
17	TOTAL PA	558,803	13,798,377	23,097,469	$ 250,688,293	$ 15,657,352	$ 266,345,645	$ 1,057,915,843	$ 1,324,261,488	57.31%	$ 152,642,382	$ 418,988,027	$ -	$ 418,988,027	$ 1,057,915,843	$ 1,476,903,870	11.53%
18	REDUCTION IN DSS & HPS DEFAULT SERVICE RIDER TO REFLECT LOWER UNCOLLECTIBLE CHARGE								0		0	$ -	$ -	$ -	$ (716,000)	$ (716,000)	
19	TOTAL								$ 1,324,261,488		$ 152,642,382	$ 418,988,027	$ -	$ 418,988,027	$ 1,057,199,843	$ 1,476,187,870	11.47%

*Includes billed kW, minimum kW, and standby kW

Met-Ed Exhibit KMS-3
Witness: K.M. Siedt

METROPOLITAN EDISON COMPANY
DEVELOPMENT OF PROPOSED KVAR CHARGES

			Met-Ed	
1	Rate of Return			
2	Debt		3.11%	
3	Equity		5.88%	
4	Subtotal		8.99%	
5	Federal and State Income Tax	*	4.16%	
6	Depreciation		1.54%	
7	Subtotal		14.69%	
8	Maintenance		0.0037%	
9	Total Carrying Charge		14.6974%	
10	Installed Cost of 1200 KVAR Capacitor		$16.14	
11	Capacitor Investment per year		$ 2.37	
12	**Capacitor Investment per month**		**$ 0.20**	**per RkVA**
13	* Tax Rate Calculation:			
14	Local, State, Federal			
15	Composite Tax		41.435%	
16	Tax Rate		4.16%	

Time of Use Agreement

Residential Time of Use Customer Class Full Requirements

for

{INSERT EDC HERE}

TIME OF USE AGREEMENT

THIS TIME OF USE AGREEMENT ("Agreement") is made and entered into as of {Insert Date} ("Effective Date") by and between the {Insert EDC Name Here} ("Company"), a corporation organized and existing under the laws of the Commonwealth of Pennsylvania and _____ ("TOU Supplier") a corporation organized and existing under the laws of [State of or Commonwealth of…..]. The Company and the TOU Supplier hereinafter are sometimes referred to collectively as the "Parties," or individually as a "Party."

WITNESSETH:

WHEREAS, the Company is an electric public utility engaged, *inter alia*, in providing retail electric service within its service territory located in the Commonwealth of Pennsylvania; and

WHEREAS, the Company's retail tariff includes a Time-of-Use ("TOU") Default Service Rider to meet its obligation under Pennsylvania Act 129 of 2008 ("Act 129") to have at least one Time-Of-Use rate available for residential Customers ("TOU Program"); and

WHEREAS, the Pennsylvania Public Utility Commission ("PaPUC" or "Commission") has found that it would serve the public interest for the Company to secure licensed Electric Generation Suppliers ("EGS") to provide residential Time-of-Use Default Service pursuant to the Company's Time-of-Use Default Service Rider; and

WHEREAS, the Company has sought and received approval from the PaPUC to randomly assign Time-of-Use default service customers to participating EGSs, if they have no preference; and

WHEREAS, the TOU Supplier is licensed by the PaPUC to offer and supply competitive retail electric service in Pennsylvania.

NOW, THEREFORE, in consideration of the mutual covenants and promises set forth below, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereto, intending to be legally bound, hereby covenant, promise and agree as follows:

Article 1: Definitions

Any capitalized or abbreviated term not elsewhere defined in this Agreement shall have the definition set forth in this Article.

1.1 **Agreement** – This Agreement for the TOU Supplier to provide default service to TOU Customers and Appendices attached hereto.

1.2 **Applicable Legal Authorities** – Those federal and Pennsylvania statutes and administrative rules, regulations and Orders that govern the electric utility industry in Pennsylvania, as they may be amended from time to time.

1.3 **Business Day** – Any day on which the Company's corporate offices are open for business.

1.4 **Consolidated EDC Billing** – Shall have the meaning set forth in the Company's Electric Generation Supplier Coordination Tariff as filed with the PaPUC and available on the Company's website.

1.5 **Customer** – Any person or entity who a:) has been provided a smart meter pursuant to the Company's PaPUC-approved smart meter plan or b:) Customers served under Rate Schedule RT as of 12/31/2014 and have existing Time-of-Use metering installed, and who enters a contractual agreement with the Company to receive retail electric service including, without limitation, all persons or entities with a Company-provided smart meter taking service under a retail tariff that are eligible to receive competitive electricity supply from an EGS or Default Service in accordance with the Applicable Legal Authorities.

1.6 **Default Service** – Shall mean Default Service as defined in 52 Pa. Code § 54.182

1.7 **Default Service Period** – Shall mean the period beginning June 1, 2015 and ending when the PaPUC approves termination of the TOU Program.

1.8 **Electronic Data Interchange or "EDI"** – A standardized format for the electronic transfer of data between different entities.

1.9 **Electric Distribution Company or "EDC" –** A public utility providing facilities for the transmission and distribution of electricity to retail Customers in Pennsylvania subject to the jurisdiction of the Commission.

1.10 **Electric Generation Supplier or "EGS"** – A person or entity that is certified by the Commission to offer and provide competitive retail electric service to retail Customers located in the Commonwealth of Pennsylvania.

1.11 **FERC** – The Federal Energy Regulatory Commission.

1.12 **PJM** – PJM Interconnection, LLC

1.13 **Rate Schedule(s)** – The Customer rate schedule(s) in the electric service tariff of the Company on file with the Commission as they may be modified from time to time.

1.14 **Rate Ready** – Shall have the meaning set forth the Company's Electric Generation Supplier Coordination Tariff as filed with the PaPUC and available on the Company's website.

1.15 **Residential Class** – Customers on Metropolitan Edison Company Rate Schedules RS and RT and Pennsylvania Electric Company Rate Schedules RS and RT as defined in the electric service tariff of the Company on file with the Commission as they may be modified from time to time.

1.16 **Seller** – The TOU Supplier.

1.17 **Service Territory** – The service territory in which the Company is authorized to furnish retail electric service in Pennsylvania.

1.18 **Supplier Tariff** - The PaPUC-approved Supplier Coordination Tariff for the Company.

1.19 **TOU** – Time of Use.

1.20 **TOU Customer(s)** – Retail Customers who are provided default service pursuant to the terms of the Company's Time-Of-Use Default Service Rider in the Company's Retail Electric Service Tariff as filed with the PaPUC and available on the Company's website.

1.21 **TOU On - Peak Price** – The price, in cents per kWh, set forth in the Company's Time-Of-Use Default Service Rider and Appendix A.

1.22 **TOU Off - Peak Price** – The price, in cents per kWh, set forth in the Company's Time-Of-Use Default Service Rider and Appendix A.

1.23 **TOU Supplier** – An entity that: (i) has accepted the obligations and associated rights to provide Time-of-Use Default Service on behalf of the Company for retail Customers in accordance with the Applicable Legal Authorities; (ii) has entered into this Agreement with the Company as a Party; (iii) is a full member of PJM and registered with PJM as a Load Serving Entity; (iv) is licensed by the PaPUC to offer and supply electric generation services in Pennsylvania; and, (v) is in full compliance with the terms and conditions of the Company's Electric Generation Supplier Coordination Tariff.

1.24 **TOU Supplier Representative** – Any officer, director, employee, consultant, contractor, or other agent or representative of the TOU Supplier having actual or apparent authority to act on behalf of the TOU Supplier in connection with TOU Supplier's performance under this Agreement. To the extent the TOU Supplier is a division or group of a company, the term "TOU Supplier Representative" excludes any person in that company who is not a part of the TOU Supplier's division or group and is specifically limited to any person in that company who is a part of the TOU Supplier's division or group.

Article 2 General Terms and Conditions

2.1 Term

This Agreement shall be effective upon execution by the Parties with the approval by the PaPUC. This Agreement may be terminated by the existence of any of the following conditions: (1) if the TOU default service is terminated by governmental action before the end of the Default Service Period; (2) if the TOU Supplier is no longer a certified EGS; (3) if either Party is in material breach of this Agreement or the Supplier Tariff; or, (4) pursuant to Article 3 of this Agreement.

2.2 Modifications to Time Of Use Agreement

This Agreement may be modified from time to time to: 1) reflect changes in the Company's Time-of-Use default service rate; or 2) with the approval of the PaPUC.

2.3 Supplier Tariff

Except as otherwise stated herein, all terms and conditions of the Company's Supplier Tariff, as modified from time to time with the approval of the PaPUC, are incorporated herein by reference, are in full force and effect, and are binding upon the parties for the duration of this Agreement.

2.4 Company Obligations and Authority

The Company shall:

(a) Have a Time-of-Use Default Service Rider that has been approved by the PaPUC effective June 1, 2015;

(b) Bill TOU Customers on behalf of the TOU Supplier under Rate Ready Consolidated EDC Billing utilizing the summer On-Peak and Off-Peak rates, and the non-summer rates calculated as specified in quarterly adjusted Appendix A;

(c) Notify Customers pursuant to the Company's PaPUC-approved smart meter plan of the availability of the Time-of-Use Default Service Rider as required by Commission regulations;

(d) Record the Customer's intent to participate and then transmit the Customer's name, address, and account number to a TOU Supplier of their choice or, if the customer has no preference, on a rotating basis via a secure website post or secure electronic data transfer;

(e) Assign Customer accounts to Seller of their choice or, if the customer has no preference, on a rotating basis, with the requisite Customer consent, consistent with the Supplier Tariff;

(f) Refer Customers that, during the Default Service Period, express an interest in Time-of-Use rates to the TOU Supplier of their choice or, if the customer has no preference, on a rotating basis designed to result in each of the participating TOU Suppliers receiving roughly the same number of TOU Customers for enrollment during a given month;

(g) Provide standard enrollment confirmation letters to TOU Customers;

(h) Notify TOU Supplier a minimum of 15 days prior to the date of a change in the TOU default service rate;

(i) Serve TOU Supplier with any filings at the PaPUC made by the Company that would modify the TOU default service rate, the Agreement, or the TOU Program;

(j) Provide monthly On-Peak and Off-Peak usage, based on actual or estimated monthly meter readings to the TOU Supplier for customers that chose or have been assigned to TOU Supplier; and

(k) Provide a TOU load profile for TOU Customers per Section 6 of the Company's Supplier Tariff, for use in estimating customer consumption for settlements as defined in Section 8 of the Company's Supplier Tariff, until such time that the Company has completed smart meter infrastructure deployment and the PaPUC has approved modifications to this Agreement and the Supplier Tariff that allow TOU Customers to be settled on an individual basis.

2.5 Obligations of the TOU Supplier

The TOU Supplier shall:

(a) Provide Competitive Energy Supply (as defined in the Supplier Tariff) to TOU Customers, consistent with the Company's Time-of-Use Default Service Rider, under the terms and conditions of service set forth in Appendix B ("TOU Supply");

(b) Meet all of the obligations and requirements of a PaPUC licensed EGS under the then-current Supplier Tariff;

(c) Cooperate with the Company in any regulatory compliance efforts that may be required to maintain the ongoing validity and enforceability of the terms of this

Agreement and the Time-of-Use Default Service Rider in the Company's retail electric service tariff, and fulfill any regulatory reporting requirement associated with the provision of TOU Supply before the PaPUC, FERC or any other regulatory body asserting jurisdiction;

(d) Utilize EDC Rate Ready Consolidated Billing to bill TOU Customers the TOU rates calculated as set forth in Appendix A and in the Company's Time-of-Use Default Service Rider;

(e) Submit the quarterly adjusted rates through the EDI protocol;

(f) Process TOU Customer enrollments, adhere to the Company's meter reading schedule, comply with the switching rules in the Supplier Tariff, mail contracts to TOU Customers providing standard terms and conditions of service as set forth in Appendix B, and maintain copies of contracts with TOU customers; and

(g) The TOU Supplier shall not drop service to an individual TOU Customer that chose or has been assigned to the TOU Supplier for TOU default service, except as requested by the TOU Customer or as provided for in Article 3.

2.6 No Guarantee of TOU Customers

Both Parties acknowledge that the Company's Time-of-Use Default Service Rider is only available to Customers in the Company's Service Territory that are in the Residential Class, that have smart metering installed in accordance with the terms of the Company's Smart Meter Technology Procurement and Installation Plan, or were served on the Companies' Rate Schedule RT as of December 31, 2014 and therefore have Time-of-Use metering installed and that affirmatively elect TOU default service during the

Default Service Period. The Company makes no guarantee or representation as to: (1) the number of residential Customers, if any, that will have smart metering installed during the term of this Agreement; (2) the number of residential Customers, if any, with smart metering installed that may enroll for service under the Time-of-Use Default Service Rider during the Default Service Period; or (3) the number of existing RT Customers as of 12/31/2014 that may enroll for service under the Time-of-Use Default Service Rider during the Default Service Period.

2.7 Fees, Penalties, and Exceptions

TOU Customers will be billed in accordance with the rates, terms and conditions of the Time-of-Use Default Service Rider in the Company's retail electric service tariff. TOU Suppliers will be paid by the Company pursuant to rates calculated in accordance with Appendix A and the terms and conditions of the Supplier Tariff. TOU Supplier will not impose any additional penalties or fees on TOU Customers other than those included in the Company's Time-of-Use Default Service Rider or Appendix B to this Agreement.

2.8 Obligation to Accept Additional Customers

The TOU Supplier will accept all referred Customers into the TOU default service who are transferred from the Company to the TOU Supplier and request enrollment during the Default Service Period.

2.9 Guaranteed Power Supply to TOU Customers for the Default Service Period

All TOU Customers enrolled in the TOU default service shall receive power at the rates calculated as set forth in Appendix A, from the TOU Customer's initial meter read date during the Default Service Period.

2.10 Default Service Period Conclusion

Upon conclusion of the Default Service Period, an enrolled TOU Customer will not automatically revert to Default Service. The TOU Supplier must inform Customers of their right to select another EGS or return to Default Service prior to the conclusion of the service period, in accordance with the notice requirements of 52 Pa. Code § 54.5(g)(1). The TOU Supplier will retain the TOU Customer unless the Customer elects a different EGS or Default Service. If the TOU Supplier retains the TOU Customer, the TOU Supplier may establish new TOU prices, without Commission approval of those prices, in the same manner as any other EGS rates.

2.11 Enrollment Procedures and Policies

TOU Customers can enroll or switch to an EGS, including an alternative offer from the TOU Supplier, at any time during the Default Service Period without restriction or penalty.

2.12 Service Inquiries and Notices to TOU Customers

TOU Customers may direct inquiries regarding this Agreement, and any power supply or billing questions regarding the Time-of-Use Default Service Rider, to the Company, at the phone number which shall be provided in all TOU default service communications with TOU Customers.

Article 3 Early Termination of Agreement

The TOU Supplier wishing to withdraw from providing TOU default service is required to do so in compliance with the procedures included in Section 13 of the Company's Supplier Tariff. The TOU Supplier may only terminate its Consumer

Contract and Disclosure Statement with TOU Customers in accordance with the terms and conditions in the form of Consumer Contract and Disclosure Statement set forth in Appendix B.

Article 4 Energy Efficiency and Conservation Programs

TOU Supplier acknowledges that TOU Customers may participate in energy efficiency and conservation programs offered by the Company (as required by Applicable Legal Authorities or otherwise), by PJM, or by other third parties, and that such participation may reduce or change the amount of TOU Supply that TOU Supplier is required to provide and, therefore, the amount of money it may receive under this Agreement. TOU Supply does not include the load which TOU Supplier may have served in the absence of such programs, and the Company shall have no obligation whatsoever to TOU Supplier with respect to the effect, if any, of such programs. TOU Supplier is solely responsible for determining the effect, if any, of such programs on future load requirements.

Article 5 Entire Agreement

This Agreement and Appendices constitute the entire Agreement and understanding between the Parties with respect to the services that are to be provided hereunder. All prior written and verbal agreements and representations, if any, with respect to these services are merged into and superseded by this Agreement. No revisions or modifications to this Agreement will be valid, unless written and executed by all Parties and approved by the PaPUC.

Article 6 Authorization

Each Party to this Agreement represents and warrants that it has full and complete authority to enter into and perform this Agreement. This includes the Company's warranty that it has the authority to enter into the Agreement and is not bound to any special contract or other commitment which will prevent the Company from discharging its obligations under this Agreement as of the commencement date. Each person who executes this Agreement on behalf of either Party represents and warrants that he or she has full and complete authority to do so and that such Party will be bound by the Agreement.

Article 7 Jurisdiction

Any and all matters of dispute between the Parties, whenever arising, shall be governed, construed and enforced in accordance with the laws of the Commonwealth of Pennsylvania regardless of the theory upon which such matter is asserted.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives to be effective as of the day and year first written above.

ATTEST: {INSERT EDC NAME HERE}

By: _____ By: _____

Name: [Insert Name] Name: [Insert Name]
Title: [Insert Title] Title: [Insert Title]

APPENDIX A

TIME OF USE PRICING

For service rendered xx/xx/xx to xx/xx/xx*

Summer Months (June – August)

TOU ON-PEAK Price **EDC's Residential $PTC_{Default}$ X x.xx**
(Met-Ed 1.28/ West Penn Power 1.28)

TOU OFF-PEAK Price **EDC's Residential $PTC_{Default}$ X x.xx**
(Met-Ed 0.82/ Penelec 0.82)

Non-Summer Months (September – May)

TOU ON-PEAK Price **EDC's Residential $PTC_{Default}$**

TOU OFF-PEAK Price **EDC's Residential $PTC_{Default}$**

* The EDC Consolidated Rate Ready Billing percentage off program used to bill the Time-of-Use Default Service Rider will first determine total customer Default Service revenue by taking the Price-To-Compare Default Service rate times the monthly On-Peak and Off-Peak kilowatt hours ("kWhs"). The revenue so determined will then be multiplied by the TOU Factors. The average rate will be calculated by dividing the kWh. As a result of rounding, the exact price per kWh will vary from the price per kWh shown above.

APPENDIX B

TIME OF USE AGREEMENT

{INSERT EGS NAME HERE} CONSUMER CONTRACT AND DISCLOSURE STATEMENT OF TERMS OF PENNSYLVANIA RESIDENTIAL ELECTRIC GENERATION SERVICE LICENSE NUMBER {Insert EGS License Number here}

Purchase of Power and Energy Service

("{INSERT EGS Name HERE}") agrees to sell, and you agree to buy, your full requirements for Time-of-Use ("TOU") default service for residential electric generation service at the price and on the terms and conditions specified in this Consumer Contract and Disclosure Statement (the "Contract"). Price and other terms of this Contract are subject to change as provided below. {INSERT EGS Name HERE} reserves the right to revoke its electricity offer for any reason at any time prior to your acceptance of this Contract. Throughout this Contract, the words "you" and "your" refer to the Customer who has signed this Contract. The words "we", "us" and "our" refer to {INSERT EGS Name HERE}. {INSERT EGS Name HERE} represents and warrants that it is an independent seller of electric generation service licensed by the Pennsylvania Public Utility Commission ("PaPUC") and is representing or acting on behalf of the Electric Distribution Company ("EDC") responsible for the service territory where you reside, e.g., West Penn Power Company or Pennsylvania Power Company (each referred to as the "Electric Distribution Company" or "EDC"). {Insert EGS Name Here} is not representing or acting on behalf of any governmental bodies, or consumer groups. You will receive written notification from the EDC confirming a pending switch of your electric generation supply.

Term

The term will begin on the starting date that is the next meter read date after the EDC processes your enrollment (the "Starting Date"). Your switch to {INSERT EGS Name HERE} will commence with the next available meter reading following the Right of Rescission Period. You have the right at anytime to terminate this service. The term will continue month to month ending with customer notice, termination or modification of the Time-Of-Use Default Service Rider by the PaPUC.

Guarantee Period

You may terminate this Contract without incurring an early termination fee at any time by selecting another Electric Generation Service Provider or returning to Default Service with the EDC. To do so, you must also notify us in writing or by calling our customer care center at {insert EGS 800 number here}. Upon your termination of this Contract, we will transfer your residential or small commercial electric generation service to be supplied by the EGS of your choice or your EDC at your next available meter read date and you will remain responsible for payment for electricity and related costs and charges incurred under this Contract through such meter read date.

Variable Pricing

By choosing the TOU default service, your price for electric generation service during the summer months of service rendered June 1 – August 31 will be the EDC's Residential $PTC_{Default}$ multiplied by x.xx (Met-Ed 1.28/Penelec 128) for On-Peak Hours and the EDC's Residential $PTC_{Default}$ multiplied by x.xx (Met-Ed 0.82/Penelec 0.82) for Off-Peak Hours. Your price for non-summer month On-Peak and Off-Peak Hours will be the EDC's Residential $PTC_{Default}$. This variable price includes generation charges (as defined below), market based transmission charges (defined below) and all Independent System Operator charges (defined below) and gross receipt taxes. This variable price does not include distribution charges (as defined below) or other EDC charges including non-market based transmission charges (which will be invoiced by the EDC), applicable state or local sales or other taxes, nor any other governmental taxes or assessments, all of which will be passed through and invoiced to you in addition to the variable price. The Price-to-Compare kWhs rate may vary from the define equation above due to rounding.

Key Pricing Definitions

"Distribution charges" are part of the basic service charges on every Customer's bill for the physical delivery of electricity from the EDC to your home. The PaPUC regulates distribution prices and services. This charge will vary according to how much electricity you use.

"Generation charges" are charges that represent the cost of producing the electricity and are specific to this Contract. Generation prices and charges are set by the electric generation supplier you have chosen, which is {INSERT EGS Name HERE}. This charge will vary according to how much electricity you use.

"Independent System Operator charges" are charges for services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system

"Market Based Transmission & Ancillary Service charges" are charges that represent the market based costs of transporting electricity from the source of supply to the EDC. This

charge will vary with your source of supply. The Federal Energy Regulatory Commission regulates transmission prices and services.

"Non-Market Based Transmission Charges" are part of the basic service charges on every Customer's bill for delivering electricity from the EDC to your home. These services include Non Market Based Charges which consist of Regional Transmission Expansion Plan Costs ("RTEP") charges billed under Schedule 6 of the PJM Operating Agreement, and PJM Expansion costs billed under Schedule 12 and 13 of the PJM Open Access Transmission Tariff. RTEPs and PJM Expansion Costs are billed by the Independent System Operator, and will be included on your bill from the EDC.

"Non-Summer Months" are the months of September through May.

"On-Peak Hours" are the hours from 8:00 a.m. to 8:00 p.m. weekdays.

"Off-Peak Hours" are the hours from 8:00 p.m. to 800 a.m. weekdays and all hours during weekends and recognized holidays observed for New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

"Price-to-Compare" is a quarterly adjusted rate, in cents per kWh, representing the Company's costs to provide Default Service to a Customer.

"PTC" See "Price-to-Compare" (defined above).

"$PTC_{Default}$" See "Price-to-Compare" (defined above).

"Summer Months" are the months of June through August.

Other Pricing Terms

The price charged for electric generation and market based transmission service under this Contract is reflective of competitive market conditions, was not set or approved by the PaPUC and does not include any applicable taxes (other than gross receipts taxes) or local distribution company fees or charges, which will be charged by the EDC. Based on the information provided by you during your signup, this address is your personal residence, vacation home or residential rental property or you are the parent or guardian for the person residing here, and you are paying the EDC bill. Accordingly, under current applicable laws, we are not required to assess sales taxes on our charges under this Contract. There is no charge for entering into this Contract or for terminating this Contract at the end of the then applicable Contract term as provided in the "Term" and "Guarantee Period" sections.

Right of Rescission

You may cancel this Contract at any time before midnight of the third business day after receiving this disclosure by either notifying us in writing at the address provided below or

by phone by calling us at {insert EGS 800 number here} that you would like to rescind this Contract.

Price Comparison

Because the EDC's tariff rates and other factors relevant to the EDC's current Residential Price-To- Compare shall change, {INSERT EGS Name HERE} cannot guarantee savings over the EDC's standard Default Service rates for the entire term of this Contract and any savings are limited to a comparison against the EDC's Residential Price-To- Compare applicable at the time you enter into this Contract, and your ability to shift load from On-Peak to Off-Peak periods.

Net Metering

If you currently own or plan to install during the term of this Contract solar, wind, or other eligible renewable electrical generating facilities in order to supply all or part of your electricity usage and such generating facility is or will be net metered by the EDC you must notify us in order for us to determine your eligibility and to properly enroll or continue to serve you.

Initiation of Service

THE PURPOSE OF THIS DOCUMENT IS TO AUTHORIZE {INSERT EGS NAME HERE} TO CHANGE YOUR ELECTRIC GENERATION SERVICE SUPPLIER AND, BY ENTERING INTO THIS CONTRACT, YOU AUTHORIZE {INSERT EGS Name HERE} TO UNDERTAKE WHATEVER STEPS NECESSARY TO ACCOMPLISH YOUR SWITCH. {INSERT EGS Name HERE} will begin providing electric generation service to you on the next applicable meter read date after the EGS processes your enrollment and your service will continue throughout the term of this Contract. The EDC will notify you of the date on which your electric generation service from {INSERT EGS Name HERE} will begin. {INSERT EGS Name HERE}'s electric generation service will be delivered to your residence using the EDC's electricity distribution wires. You represent and warrant that the electricity supply being purchased under this Contract is to be used solely for residential purposes. {INSERT EGS Name HERE}'s obligations under this Contract are conditioned on you providing complete and accurate information and on you remaining a EDC distribution Customer throughout the term under the applicable residential electric rate class.

Billing and Payment

The cost of your electric generation service will be included on your bill from the EDC, and is due and payable when your EDC bill is due at the billing address provided in your

EDC bill. You acknowledge that the EDC may provide us with your billing and payment information. You will be invoiced for {INSERT EGS Name HERE}'s charges under this Contract at the applicable price set forth in the "**Variable Pricing**" section above multiplied by your electricity usage as measured by the EDC in kWh during the applicable billing period. You agree to accept the measurements as determined by the EDC for purposes of accounting for the amount of power and energy services provided by us under this Contract. If the EDC is unable to read your meter, the EDC will estimate your usage and your charges will be calculated accordingly and adjusted on a future bill. Supplying you under this Contract is conditioned on the EDC accepting our enrollment of your account and your continued eligibility for consolidated billing by the EDC. If you are not eligible for consolidated billing, you need to remedy that restriction with the EDC before we can serve you. Should the EDC cease providing consolidated billing for your account and/or commence billing us for any charges relating to you, we will bill you and you will pay us for all such charges. You will be billed additional charges, including taxes and charges to distribute the electricity to your home, from the EDC consistent with its filed tariffs. You are responsible for paying any new or increased taxes, fees or other charges imposed on us or you in connection with our supply of electricity to you during the term of this Contract. {INSERT EGS Name HERE} reserves the right to change billing methods, upon the completion of the term of this Contract. If we change our billing methods, we will send you two (2) advance written notices either in your bills or in separate mailing before the effective date of any such change.

Equal Payment Plan

The EDC is offering an Equal Payment Plan for our electric generation service charges. You may elect the Equal Payment Plan at any time by contacting the EDC's customer service department as long as you are not past due on your payments and are eligible for EDC consolidated billing. The Equal Payment Plan is calculated by estimating your Delivery Service Charges and electric generation service charges for a twelve (12) month period. A payment of approximately one-twelfth (1/12) of such estimate shall be rendered monthly by the EDC, subject to a monthly historical review by the EDC which may result in a change in the equal payment monthly amount to be paid by the Customer. The EDC will true up your account based on your actual charges upon termination of service or if you wish to discontinue Equal Payment Plan. For more information or to signup for the Equal Payment Plan, contact the EDC customer service center at the number shown below.

Late or Insufficient Payment

When the EDC issues you a consolidated bill, all invoiced balances under this Contract that are not paid in full by the due date will be subject to the EDC's late payment policies and procedures, including imposition of late fees, interest and other charges as described in the EDC's filed tariff(s) pursuant to the terms of the Company's Time-of-Use Default Service Rider. In addition, the EDC will have the ability to terminate service to a Customer for the Customer's non-payment of either EGS Basic Electric Supply charges or EDC charges.

Credit

In the event that the EDC does not continue to purchase the right to receive your payments during the term of this contract, {INSERT EGS Name HERE} reserves the right to determine if your credit standing is satisfactory for originating or continuing electric generation service under this Contract. Consistent with applicable law, {INSERT EGS Name HERE} uses uniform income, deposit and credit requirements in determining whether to offer service to our Customers. You hereby authorize {INSERT EGS Name HERE} to perform a credit check on you if the EDC does not continue to purchase the right to receive your payments.

Termination

{INSERT EGS Name HERE} may terminate this Contract if:

- You move within or outside of the EDC's service territory or you fail to remain an EDC distribution Customer throughout the term under the applicable residential electric rate class;
- You fail to be eligible for EDC consolidated billing throughout the term;
- You rescind your authorization for release of information provided in the "**Information Release Authorization**" section below; or,
- You provide any false, inaccurate or misleading information to {INSERT EGS Name HERE} or the EDC.

YOU MAY TERMINATE THIS CONTRACT PRIOR TO THE END OF THE APPLICABLE TERM FOR YOUR CONVENIENCE BY GIVING US NOT LESS THAN 30 DAYS' PRIOR WRITTEN NOTICE.

Upon any termination of this Contract, you will need to select another service offered by this EGS, select another electric generation supplier or return to the EDC's standard Default Service. The effective date of any termination will be the next applicable meter read date after expiration of the required notice period. Upon any termination, you will remain responsible for all obligations, including payment for electricity and related costs and charges incurred under this Contract prior to the effective date of termination. The delivery of electricity to you cannot be terminated or interrupted by the EDC as a result of any dispute between {INSERT EGS Name HERE} and you but may be terminated by the EDC for nonpayment of EDC charges in accordance with applicable law. The EDC will continue to respond to any service calls and emergencies and switching to {INSERT EGS Name HERE} will not impact your electric service reliability. Because the EDC purchases the right to receive your payments under this Contract, your payment obligations under this Contract are EDC charges for purposes of termination of service.

Assignment, Address Change

{INSERT EGS Name HERE} may assign, subcontract or delegate all or any part of our rights and/or obligations under this Contract, including your payment obligations under this Contract, without notice or your consent in accordance with the rules and regulations of the PaPUC. You may not assign any of your rights or obligations under this Contract without our prior written consent. If you move, you may terminate our Contract. You will be responsible for paying for all electricity supplied to your old address until the date this Contract is terminated in accordance with its terms. If you move within the EDC's service territory, you must contact the EDC at the number provided in the "**Contact Information**" section below in order to obtain new account and meter numbers for your new residence. Please contact us if you would like us to serve you again at your new location.

Change in Terms

This Contract may be revised at any time by {INSERT EGS Name HERE} upon the Commission's approved modifications to TOU default service. Whenever changes to the terms of service in this Contract are proposed, you will receive two written notifications from us in corresponding separate mailings that precede either the expiration date or the effective date of the proposed changes. We will explain your options to you in these two advance notifications. The first of these notices will occur between 52 and 90 days prior to the expiration date of the Contract or the effective date of the proposed Contract change; the second of these notices will occur at least 45 days prior to the Contract's expiration or the effective date of the proposed Contract change. You will have an opportunity to terminate this Contract without any further obligation by notifying us in writing within 30 days after the date of the second notice of the new terms and conditions, in which case your electric generation service will terminate effective as of the next meter read date after expiration of the required notice period. You will remain responsible for any unpaid balance as of the termination date.

Information Release Authorization

Throughout the term, you authorize {INSERT EGS Name HERE} to obtain information from the EDC that includes, but is not limited to, account name, account number, billing address, service address, telephone number, standard offer service type, historical and future electricity usage, rate classification, meter readings, characteristics of electricity service and, when charges hereunder are included on your EDC bill, billing and payment information from the EDC. You authorize {INSERT EGS Name HERE} to release such information to third parties that need to know such information in connection with your power and energy service and to {INSERT EGS Name HERE}'s affiliates and subcontractors. These authorizations will remain in effect as long as this Contract is in effect. You may rescind these authorizations at any time by either calling or providing written notice to us. We reserve the right to the extent permitted by law to reject your enrollment or terminate this Contract in the event these authorizations are rescinded.

Dispute Resolution

If you have a billing or other dispute involving our service, please contact us at {Insert EGS 800 number here}. You must still pay your bill in full, but may deduct the specific amount in dispute while the charges remain in dispute. You may call the PaPUC if you are not satisfied after discussing the terms with us at 1-888-PUC-FACT or 1-800-782-1100 from 8:00 am to 5:00 pm weekdays or in writing at P.O. Box 3265, Harrisburg, PA 17105-3265.

Limitation of Liability; Jury Trial Waiver

You agree that neither {INSERT EGS Name HERE} nor any of its affiliates or subcontractors will be liable for any damages or claims for matters within the control of the EDC or the ISO controlled electricity grid, which include maintenance of electric lines and systems, service interruptions, loss or termination of service, deterioration of electric services, meter readings or injury to persons or damage to property caused by the delivery or supply of electricity. Neither {INSERT EGS Name HERE} nor any of its affiliates or subcontractors will be responsible for any failure to commence or terminate power and energy service on the date specified herein due to any failure or delay in enrolling you with the EDC. {INSERT EGS Name HERE}'s liability will be limited to direct actual damages only, which will not exceed the amount of your single largest monthly invoice during the preceding 2 years. In no event will {INSERT EGS Name HERE} or any of its affiliates or subcontractors be liable for any punitive, incidental, consequential, exemplary, indirect, third-party claims or other damages whether based on contract, warranty, tort, negligence, strict liability or otherwise, or for lost profits arising from any breach or nonperformance of this Contract. BOTH YOU AND {INSERT EGS NAME HERE} AGREE IRREVOCABLY AND UNCONDITIONALLY TO WAIVE ANY RIGHT TO A TRIAL BY JURY OR TO INITIATE OR BECOME A PARTY TO ANY CLASS ACTION CLAIMS IN RESPECT OF ANY ACTION, SUIT OR PROCEEDING DIRECTLY OR INDIRECTLY ARISING OUT OF OR RELATING TO THIS CONTRACT OR THE TRANSACTIONS CONTEMPLATED BY THIS CONTRACT.

Force Majeure

We do not transmit or deliver electricity and causes and events out of our reasonable control ("Force Majeure Events") may result in interruptions in service. We will not be liable for any such interruptions or any other failure to perform under this Contract caused by a Force Majeure Event. We are not and will not be liable for damages caused by Force Majeure Events, including but not limited to acts of God; acts of any governmental authority; accidents; strikes; labor disputes; required maintenance work; inability to access the EDC's system; nonperformance by the EDC, including, but not limited to, a facility outage on its distribution lines; changes in laws, rules or regulations of any governmental authority; or any cause beyond our reasonable control.

Miscellaneous

Except with respect to {INSERT EGS Name HERE}'s affiliates and subcontractors under the "**Limitation of Liability; Jury Trial Waiver**" section, there are no third party beneficiaries of this Contract. Any payments due under this Contract, and all provisions relating to the payment and collection thereof, and the provisions contained in the "**Limitation of Liability; Jury Trial Waiver**" section above, will survive expiration or termination for any reason. This Contract constitutes the entire agreement between you and {INSERT EGS Name HERE}. No statement, promise or inducement made by either party not contained in this Contract will be valid or binding. Any reference to days or periods will mean calendar days.

Contact Information

{INSERT EGS Name HERE} RESIDENTIAL LICENSE NUMBER IS {Insert EGS license number here}

Should you have any questions about your {INSERT EGS Name HERE} contract or {INSERT EGS Name HERE} charges on your invoice, please contact us between the hours of 8:00 a.m. and 8:00 p.m. eastern time on weekdays, except holidays. Our toll-free number is {INSERT EGS 800 number HERE}. We can be reached by email at: {INSERT EGS WEB-SITE HERE} or by mail at: {INSERT EGS Mailing ADDRESS here}. Please contact us at this address to provide all notices under this Contract and contact us at this address or phone number to resolve any disputes regarding this Contract. For emergencies relating to your service, such as a power outage, or for information about universal service programs, please call your EDC at the following number:

Metropolitan Edison Company at 1-800-545-7441,
or Pennsylvania Electric Company at 1-800-545-7441

The Pennsylvania Utility Commission can be reached by mail
at P.O. Box 3265, Harrisburg, PA 171053265,
or by phone at 18006927380
and their website address is
http://www.puc.state.pa.us/. You may contact the PUC if after discussing with us you are not satisfied with these terms and conditions.

Metropolitan Edison Company
Rate RS - Residential Service
Revenue Effects of Proposed Rates - FTY 4/30/16

Line No.		Tariff 51, Supplement No, 44 Current Rate (1)	Billing Units (2)	Billed Revenue (3)	Tariff 52 Proposed Rate (4)	Billing Units (5)	Proposed Revenue (6)=(4)x(5)
	DISTRIBUTION CHARGES						
	CUSTOMER CHARGE						
1	RS	$8.11	5,335,068	$43,267,406	$ 13.29	5,335,068	$70,903,054
2	**DEMAND CHARGES**	$2.00	13,704	$27,408	$ 2.00	13,704	$27,408
	ENERGY CHARGES						
3	All KWH	$0.02328	4,659,445,780	$108,471,909	$ 0.04103	4,659,445,780	$191,177,060
4	**TOTAL BASE NORMALIZED DISTRIBUTION REVENUES**			**$ 151,766,723**			**$ 262,107,522**
5	Smart Meter Technologies Charge (Per Bill)	$2.34	5,335,068	$12,468,706	$0	-	$0
6	**TOTAL DISTRIBUTION INCLUDING RIDER CHANGES**			**164,235,429**			**262,107,522**
	RIDER CHARGES						
7	NUG	$0.00015	4,659,445,780	$1,975,769	$0.00015	4,659,445,780	$1,975,769
8	Consumer Education	$0.00005	4,659,445,780	$0	$0.00005	4,659,445,780	$0
9	Energy Efficiency and Conservation Charge	$0.00074	4,659,445,780	$0	$0.00074	4,659,445,780	$0
10	Default Service Support Charge	$0.00401	4,659,445,780	$18,766,921	$0.00401	4,659,445,780	$18,766,921
11	Universal Service Charge	$0.00529	4,659,445,780	$24,757,360	$0.00529	4,659,445,780	$24,757,360
12	Solar Photovoltaic Requirements Charge	$0.00022	4,659,445,780	$1,038,967	$0.00022	4,659,445,780	$1,038,967
13	Phase II Energy Efficiency and Conservation Charge	$0.00316	4,659,445,780	$14,788,895	$0.00316	4,659,445,780	$14,788,895
14	PTC*	$0.08198	4,659,445,780	$381,981,365	$0.08198	4,659,445,780	$381,981,365
15	STAS	-0.29%	0	$0	0%	0	$0
16	Total Energy and Revenue		4,659,445,780	**$607,544,706**		$4,659,445,780	**$705,416,799**
17	Avg rate per kWh			$0.13039			$0.15140
18	Proposed Increase						$97,872,093
19	Percent Increase						16.11%

Metropolitan Edison Company
Rate RT - Residential Service Time of Day
Revenue Effects of Proposed Rates - FTY 4/30/16

Line No.		Tariff 51, Supplement No, 44 Current Rate (1)	Billing Units (2)	Billed Revenue (3)	Tariff 52 Proposed Rate (4)	Billing Units (5)	Proposed Revenue (6)=(4)x(5)
	DISTRIBUTION CHARGES						
	CUSTOMER CHARGE						
1	RT **(to RS)**	$11.00	563,588	$6,199,468	$ 13.29	564,624	$7,503,853
	Solar Water Heating System **(to RS)**	$9.45	1,036	$9,789			
2	**DEMAND CHARGES (to RS)**	$2.00	285	$570	$ 2.00	285	$570
	ENERGY CHARGES						
3	On Peak kWh	$0.05043	255,440,765	$12,881,878	$0	0	$0
4	Off Peak kWh	$0.00283	474,991,090	$1,344,225	$0	0	$0
5	Summer On Peak kWh	$0.03526	482,069	$16,998	$0	0	$0
6	Summer Off Peak kWh	$0.00283	896,406	$2,537	$0	0	$0
7	Non-Summer On Peak kWh	$0.01946	1,888,272	$36,746	$0	0	$0
8	Non-Summer Off Peak kWh	$0.00283	3,511,234	$9,937	$0	0	$0
9	Proposed RS **(to RS)**		737,209,836	$14,292,321	$ 0.04103	737,209,836	$30,247,720
10	**TOTAL BASE NORMALIZED DISTRIBUTION REVENUES**			**$20,502,148**			**$37,752,143**
11	Smart Meter Technologies Charge (Per Bill)	$2.33	564,624	$1,316,102	$0	564,624	$0
12	**TOTAL DISTRIBUTION INCLUDING RIDER CHANGES**			**$21,818,250**			**$37,752,143**
	RIDER CHARGES						
13	NUG	$0.00015	737,209,836	$295,276	$0.00015	737,209,836	$295,276
14	Consumer Education	$0.00005	737,209,836	$0	$0.00005	737,209,836	$0
15	Energy Efficiency and Conservation Charge	$0.00074	737,209,836	$0	$0.00074	737,209,836	$0
16	Default Service Support Charge	$0.00377	737,209,836	$2,785,491	$0.00377	737,209,836	$2,785,491
17	Universal Service Charge	$0.00529	737,209,836	$3,910,629	$0.00529	737,209,836	$3,910,629
18	Solar Photovoltaic Requirements Charge	$0.00022	737,209,836	$164,113	$0.00022	737,209,836	$164,113
19	Phase II Energy Efficiency and Conservation Charge	$0.00316	737,209,836	$2,336,028	$0.00316	737,209,836	$2,336,028
20	PTC*	$0.08198	737,209,836	$60,436,462	$0.08198	737,209,836	$60,436,462
21	STAS	-0.29%		$0	0%		$0
22	Total Energy and Revenue		737,209,836	**$91,746,249**		737,209,836	**$107,680,142**
23	Avg rate per kWh			$0.12445			$0.14606
24	Proposed Increase						$15,933,893
25	Percent Increase						17.37%

Metropolitan Edison Company
Rate GS - Volunteer Fire Company and Non-Profit Ambulance Service, Rescue Squad and Senior Center Service Rate
Revenue Effects of Proposed Rates - FTY 4/30/16

Line No.		Tariff 51, Supplement No, 44 Current Rate (1)	Billing Units (2)	Billed Revenue (3)	Tariff 52 Proposed Rate (4)	Billing Units (5)	Proposed Revenue (6)=(4)x(5)
	DISTRIBUTION CHARGES						
	CUSTOMER CHARGES						
1	RT Rate	$11.00	1,396	$15,355			
2	RS Rate	$8.11	1,928	$15,635			
3	Proposed RS		3,324	30,990	$13.29	3,324	$44,176
4	**DEMAND CHARGES**	$2.00	23,835	$47,670	$ 2.00	23,835	$47,670
	ENERGY CHARGES						
5	All KWH RS Rate	$0.02328	6,260,679	$145,750			
6	On Peak Energy Charge RT	$0.05043	2,011,887	$101,460			
7	Off Peak Energy Charge RT	$0.00283	3,834,116	$10,851			
8	Summer On Peak Energy Charge RT	$0.03526	0	$0			
9	Summer Off Peak Energy Charge RT	$0.00283	0	$0			
10	Non-Summer On Peak Energy Charge RT	$0.01946	0	$0			
11	Non-Summer Off Peak Energy Charge RT	$0.00283	0	$0			
12	Proposed RS		12,106,682	$258,061	$0.04103	12,106,682	$496,737
13	**TOTAL BASE NORMALIZED DISTRIBUTION REVENUES**			**$336,721**			**$588,583**
14	Smart Meter Technologies Charge (Per Bill)	$2.33	3,324	$7,736	$0	3,324	$0
15	**TOTAL DISTRIBUTION INCLUDING RIDER CHANGES**			**344,457**			**588,583**
	RIDER CHARGES						
16	NUG	$0.00015	12,106,682	$4,907	$0.00015	12,106,682	$4,907
17	Consumer Education	$0.00005	12,106,682	$0	$0.00005	12,106,682	$0
18	Energy Efficiency and Conservation Charge	$0.00108	12,106,682	$0	$0.00108	12,106,682	$0
19	RS - Default Service Support Charge	$0.00401	12,106,682	$47,032	$0.00401	12,106,682	$47,032
20	Universal Service Charge	$0.00529	12,106,682	$63,945	$0.00529	12,106,682	$63,945
21	Solar Photovoltaic Requirements Charge	$0.00022	12,106,682	$2,683	$0.00022	12,106,682	$2,683
22	Phase II Energy Efficiency and Conservation Charge	$0.00103	12,106,682	$12,450	$0.00103	12,106,682	$12,450
23	PTC*	$0.08198	12,106,682	$992,506	$0.08198	12,106,682	$992,506
24	STAS	-0.29%		$0	0%		$0
25	Total Energy and Revenue		12,106,682	**1,467,980**		12,106,682	**1,712,106**
26	Avg rate per kWh			$0.12125			$0.14142
27	Proposed Increase						$244,126
28	Percent Increase						16.63%

Metropolitan Edison Company
Rate GS-Small and GS-Medium - General Service Secondary
Revenue Effects of Proposed Rates - FTY 4/30/16

Line No.		Tariff 51, Supplement No, 44			Tariff 52		
		Current Rate	Billing Units	Billed Revenue	Proposed Rate	Billing Units	Proposed Revenue
		(1)	(2)	(3)	(4)	(5)	(6)=(4)x(5)
	DISTRIBUTION CHARGES						
	CUSTOMER CHARGES						
1	GS - Small	$10.88	474,660	5,164,330	$ 16.53	474,660	$ 7,846,130
2	GS - Medium Single Phase	$10.88	134,231	$1,460,433			
3	GS - Medium Single Phase 12 Hour On-Peak Time-of-Day	$10.88	4,900	$53,312			
4	GS - Medium Single Phase 8 Hour On-Peak Time-of-Day	$10.88	1,064	$11,576			
5	GS-Medium Single Phase Total		140,195	$1,525,321	$ 19.01	140,195	$ 2,665,107
6	GS - Medium Three Phase	$21.52	143,514	$3,088,420			
7	GS - Medium Three Phase 12 Hour On-Peak Time-of-Day	$21.52	9,422	$202,761			
8	GS - Medium Three Phase 8 Hour On-Peak Time-of-Day	$21.52	2,009	$43,234			
9	GS-Medium Three Phase Total		154,945	$3,334,415	$ 34.39	154,945	$ 5,328,559
	DEMAND CHARGES						
10	GS - Medium Single Phase (Per kW)	$3.82	1,776,519	$6,786,301			
11	GS - Medium Single Phase 12 Hour On-Peak Time-of-Day (Per kW)	$3.82	126,137	$481,843			
12	GS - Medium Single Phase 8 Hour On-Peak Time-of-Day (Per kW)	$3.82	16,908	$64,589			
	GS-Medium Single Phase Total		1,919,564	$7,332,733	$5.22	1,919,564	$ 10,020,124
13	GS - Medium Three Phase (Per kW)	$3.82	5,768,365	$22,035,147			
14	GS - Medium Three Phase 12 Hour On-Peak Time-of-Day (Per kW)	$3.82	1,009,246	$3,855,319			
15	GS - Medium Three Phase 8 Hour On-Peak Time-of-Day (Per kW)	$3.82	125,521	$479,490			
	GS-Medium Three Phase Total		6,903,132	$26,369,956	$5.22	6,903,132	$ 36,034,349
16	GS - Medium Minimum kW	$3.82	724,461	$2,767,440	$5.22	724,461	$ 3,781,686
17	GS - Medium Single Phase (Per rkVA)	$0	100,733	$0			
18	GS - Medium Single Phase 12 Hour On-Peak Time-of-Day (Per rkVA)	$0	7,152	$0			
19	GS - Medium Single Phase 8 Hour On-Peak Time-of-Day (Per rkVA)	$0	959	$0			
20	GS-Medium Single Phase Total		108,844	$0	$ 0.20	108,844	$ 21,769
21	GS - Medium Three Phase (Per rkVA)	$0	1,738,368	$0			
22	GS - Medium Three Phase 12 Hour On-Peak Time-of-Day (Per rkVA)	$0	304,149	$0			
23	GS - Medium Three Phase 8 Hour On-Peak Time-of-Day (Per rkVA)	$0	37,827	$0			
24	GS-Medium Three Phase Total		2,080,344	$0	$ 0.20	2,080,344	$ 416,069
	ENERGY CHARGES						
25	GS - Small	$0.01264	211,718,699	$2,676,139	$0.03082	211,718,699	$ 6,525,170
26	GS - Medium Single Phase	$0.00050	493,154,376	$246,577			
27	GS - Medium Single Phase 12 Hour On-Peak Time-of-Day	$0.00050	21,130,483	$10,565			
28	GS - Medium Single Phase 12 Hour Off-Peak Time-of-Day	$0.00050	15,059,134	$7,530			
29	GS - Medium Single Phase 8 Hour On-Peak Time-of-Day	$0.00050	2,313,190	$1,157			
30	GS - Medium Single Phase 8 Hour Off-Peak Time-of-Day	$0.00050	3,709,236	$1,855			
31	GS-Medium Single Phase Total		535,366,419	$267,684	$0.00000	535,366,419	$ -

Metropolitan Edison Company
Rate GS-Small and GS-Medium - General Service Secondary
Revenue Effects of Proposed Rates - FTY 4/30/16

		Tariff 51, Supplement No, 44			Tariff 52		
		Current Rate	Billing Units	Billed Revenue	Proposed Rate	Billing Units	Proposed Revenue
		(1)	(2)	(3)	(4)	(5)	(6)=(4)x(5)
32	GS-Medium Three Phase	$0.00050	1,822,200,312	$911,100			
33	GS - Medium Three Phase 12 Hour On-Peak Time-of-Day	$0.00050	191,304,790	$95,652			
34	GS - Medium Three Phase 12 Hour Off-Peak Time-of-Day	$0.00050	136,337,847	$68,169			
35	GS - Medium Three Phase 8 Hour On-Peak Time-of-Day	$0.00050	18,740,172	$9,370			
36	GS - Medium Three Phase 8 Hour Off-Peak Time-of-Day	$0.00050	30,050,153	$15,025			
37	GS-Medium Three Phase Total		2,198,633,274	$1,099,316	$0.00000	2,198,633,274	$ -
38	**TOTAL BASE NORMALIZED DISTRIBUTION REVENUES**			**$50,537,334**			**72,638,963**
39	Smart Meter Technologies Charge (Per Bill) - GS Small		474,660	$1,131,598		474,660	$0
40	Smart Meter Technologies Charge (Per Bill) - GS Medium		295,140	$703,619		295,140	$0
41	Smart Meter Technologies Charge (Per Bill) - Total	$2.38	769,800	$1,835,217	$0	769,800	$0
42	**TOTAL DISTRIBUTION INCLUDING RIDER CHANGES**			**$52,372,551**			**72,638,963**
	RIDER CHARGES						
43	NUG	($0.00002)	2,945,718,392	$1,176,659	($0.00002)	2,945,718,392	$1,176,659
44	Consumer Education	$0.00003	2,945,718,392	$0	$0.00003	2,945,718,392	$0
45	Energy Efficiency and Conservation Charge	($0.00003)	2,945,718,392	$0	($0.00003)	2,945,718,392	$0
46	Default Service Support Charge GS - Small	$0.00260	211,718,699	$550,206	$0.00260	211,718,699	$550,206
47	Default Service Support Charge GS - Medium	$0.00248	2,733,999,693	$6,655,737	$0.00248	2,733,999,693	$6,655,737
48	Universal Service Charge	$0	0	$0	$0	0	$0
49	Solar Photovoltaic Requirements Charge	$0.00022	2,945,718,392	$642,753	$0.00022	2,945,718,392	$642,753
50	Phase II Energy Efficiency and Conservation Charge	$0.00185	2,945,718,392	$5,356,272	$0.00185	2,945,718,392	$5,356,272
51	PTC*	$0.08048	2,945,718,392	$0 $237,071,416	$0.08048	2,945,718,392	$237,071,416
52	STAS	-0.29%		$0	0%		$0
53	Total Energy and Revenue		2,945,718,392	**303,825,594**		2,945,718,392	**324,092,006**
	Total Energy and Revenue - GS Small		211,718,699	**27,044,844**		211,718,699	**32,444,077**
	Total Energy and Revenue - GS Medium		2,733,999,693	**276,780,750**		2,733,999,693	**291,647,929**
				-			-
54	Avg rate per kWh			$0.10314			$0.11002
55	Proposed Increase - GS Small						5,399,233
54	Proposed Increase - GS Medium						14,867,179
55	Percent Increase - GS Small						19.96%
56	Percent Increase - GS Medium						5.37%

Metropolitan Edison Company
Rate GS-Large - General Service Secondary Time of Day
Revenue Effects of Proposed Rates - FTY 4/30/16

Line No.		Tariff 51, Supplement No. 44 Current Rate (1)	Billing Units (2)	Billed Revenue (3)	Tariff 52 Proposed Rate (4)	Billing Units (5)	Proposed Revenue (6)=(4)x(5)
	DISTRIBUTION CHARGES						
	CUSTOMER CHARGES						
1	GS - Large 12 Hour On-Peak Time-of-Day	$60.98	4,008	$244,396			
2	GS - Large 8 Hour On-Peak Time-of-Day	$60.98	456	$27,806			
	GS-Large Proposed		4,464	$272,202	$ 93.87	4,464	419,036
	DEMAND CHARGES						
3	GS - Large 12 Hour On-Peak Time-of-Day (Per kW)	$2.43	2,142,743	$5,206,616			
4	GS - Large 8 Hour On-Peak Time-of-Day (Per kW)	$2.43	191,281	$464,791			
5	GS-Large Proposed (Per kW)		2,334,024	$5,671,407	$3.63	2,334,024	8,472,507
6	GS - Large 12 Hour On-Peak Time-of-Day (Per rkVA)	$0	1,278,185	$0			
7	GS - Large 8 Hour On-Peak Time-of-Day (Per rkVA)	$0	114,103	$0			
8	GS-Large Proposed (Per rkVA)		1,392,288	$0	$ 0.20	1,392,288	278,458
9	Minimum kW	$2.43	12,703	30,867	$3.63	12,703	46,112
	ENERGY CHARGES						
10	GS-Large 12 Hour On Peak Time-of-Day (Per KWH)	$0	504,704,902	$0			
11	GS-Large 12 Hour Off Peak Time-of-Day (Per KWH)	$0	332,107,041	$0			
12	GS-Large 8 Hour On Peak Time-of-Day (Per KWH)	$0	34,637,726	$0			
13	GS-Large 8 Hour Off Peak Time-of-Day (Per KWH)	$0	51,282,885	$0			
14	GS-Large Proposed (Per kWh)		922,732,554	$0	$0	922,732,554	-
15	**TOTAL BASE NORMALIZED DISTRIBUTION REVENUES**			**$5,974,476**			**$9,216,113**
16	Smart Meter Technologies Charge (Per Bill)	$2.40	4,464	$10,720	$0	4,464	$0
17	**TOTAL DISTRIBUTION INCLUDING RIDER CHANGES**			**$5,985,196**			**$9,216,113**
	RIDER CHARGES						
18	Energy Efficiency and Conservation Charge (Per kW PLC)	($0.02)	1,991,676	$0	($0.02)	1,991,676	$0
19	Default Service Support Charge (Per kW NSPL)	$1.053	2,033,858	$2,140,941	$1.053	2,033,858	$2,140,941
20	Phase II Energy Efficiency and Conservation Charge (Per kW PLC)	$0.50	1,991,676	$995,838	$0.50	1,991,676	$995,838
22	NUG	($0.00002)	922,732,554	$386,448	($0.00002)	922,732,554	$386,448
21	Consumer Education	$0.00003	922,732,554	$0	$0.00003	922,732,554	$0
23	Universal Service Charge	$0	0	$0	$0	0	$0
24	Hourly Priced Generation*	$0.05442	922,732,554	$50,215,106	$0.05442	922,732,554	$50,215,106
25	Solar Photovoltaic Requirements Charge	$0.00022	922,732,554	$210,934	$0.00022	922,732,554	$210,934
26	STAS	-0.29%		$0	0%		$0
27	Total Energy and Revenue		922,732,554	$59,934,463		922,732,554	$63,165,380
28	Avg rate per kWh			$0.06495			$0.06845
29	Proposed Increase						$3,230,917
30	Percent Increase						5.39%

Metropolitan Edison Company
Rate GP - General Primary Service
Revenue Effects of Proposed Rates - FTY 4/30/16

Line No.		Tariff 51, Supplement No, 44 Current Rate (1)	Billing Units (2)	Billed Revenue (3)	Tariff 52 Proposed Rate (4)	Billing Units (5)	Proposed Revenue (6)=(4)x(5)
	DISTRIBUTION CHARGES						
	CUSTOMER CHARGES						
1	GP 12 Hour On Peak Time-of-Day	$235.28	3,840	$903,475			
2	GP 8 Hour On Peak Time-of-Day	$235.28	1,752	$412,211			
			5,592	$1,315,686	$ 308.19	5,592	$ 1,723,398
	DEMAND CHARGES						
3	GP 12 Hour On Peak Time-of-Day (Per kW)	$1.46	4,023,225	$5,873,908			
4	GP 8 Hour On Peak Time-of-Day (Per kW)	$1.46	2,696,186	$3,936,432			
			6,719,411	$9,810,340	$3.35	6,719,411	$ 22,510,027
5	GP 12 Hour On Peak Time-of-Day (Per rkVA)	$0	1,992,217	$0			
6	GP 8 Hour On Peak Time-of-Day (Per rkVA)	$0	1,335,095	$0			
			3,327,312	$0	$ 0.20	3,327,312	$ 665,462
7	Minimum kW	$1.46	108,343	$158,181	$3.35	108,343	$ 362,949
8	Rule 18 Backup Demand kW	$0.92	220,309	$202,684	$2.51	220,309	$ 552,976
	ENERGY CHARGES						
9	12 Hour On Peak Time-of-Day (Per KWH)	$0.00066	1,047,688,723	$691,475			
10	12 Hour Off Peak Time-of-Day (Per KWH)	$0.00066	847,832,156	$559,569			
11	8 Hour On Peak Time-of-Day (Per KWH)	$0.00066	330,712,557	$218,270			
12	8 Hour Off Peak Time-of-Day (Per KWH)	$0.00066	602,158,496	$397,425			
13	All KWH		2,828,391,932	$1,866,739	$0.00000	2,828,391,932	$ -
14	**TOTAL BASE NORMALIZED DISTRIBUTION REVENUES**			**$13,353,630**			**$ 25,814,812**
15	Smart Meter Technologies Charge (Per Bill)	$2.32	5,592	$12,984	$0	5,592	$0
16	**TOTAL DISTRIBUTION INCLUDING RIDER CHANGES**			**$13,366,614**			**$25,814,812**
	RIDER CHARGES						
17	Energy Efficiency (Per kW PLC)	($0.02)	4,875,247	$0	($0.02)	4,875,247	$0
18	Default Service Support (Per kW NSPL)	$1.006	5,167,730	$5,195,156	$1.006	5,167,730	$5,195,156
19	Phase II Energy Efficiency (Per kW PLC)	$0.50	4,875,247	$2,437,623	$0.50	4,875,247	$2,437,623
20	NUG	$0.00037	2,828,391,932	$1,216,329	$0.00037	2,828,391,932	$1,216,329
21	Consumer Education	$0.00000	2,828,391,932	$0	$0.00000	2,828,391,932	$0
22	Universal Service Charge	$0.00	0	$0	$0.00	0	$0
23	Hourly Priced Generation- Energy*	$0.05262	2,828,391,932	$148,829,983	$0.05262	2,828,391,932	$148,829,983
24	Solar Photovoltaic Requirements Charge	$0.00022	2,828,391,932	$624,232	$0.00022	2,828,391,932	$624,232
25	STAS	-0.29%		$0	0%		$0
26	Total Energy and Revenue		2,828,391,932	$171,669,937		2,828,391,932	$184,118,135
27	Avg rate per kWh			$0.06070			$0.06510
28	Proposed Increase						$12,448,198
29	Percent Increase						7.25%

Metropolitan Edison Company
Rate TP - Transmission Power Service
Revenue Effects of Proposed Rates - FTY 4/30/16

Line No.		Tariff 51, Supplement No, 44 Current Rate (1)	Billing Units (2)	Billed Revenue (3)	Tariff 52 Proposed Rate (4)	Billing Units (5)	Proposed Revenue (6)=(4)x(5)
	DISTRIBUTION CHARGES						
	CUSTOMER CHARGES						
1	All 12 Hour On-Peak Time-of-Day Customers	$882.16	144	$126,052			
2	All 8 Hour On-Peak Time-of-Day Customers	$882.16	108	$94,539			
			252	$220,591	$ 1,149.15	252	289,586
	DEMAND CHARGES						
3	All 12 Hour On-Peak Time-of-Day KW (Per KW)	$0.64	198,178	$125,856			
4	All 8 Hour On-Peak Time-of-Day KW (Per KW)	$0.64	3,206,120	$2,036,101			
			3,404,298	$2,161,957	$1.03	3,404,298	3,506,427
5	115 KV Discount (Per kW)	($0.27)	386,737	(103,614)	($0.31)	386,737	(119,888)
6	All 12 Hour On-Peak Time-of-Day rKVA (Per rkVA)	$0	86,881	$0			
7	All 8 Hour On-Peak Time-of-Day rKVA(Per rkVA)	$0	1,405,562	$0			
			1,492,443	$0	$0.00	1,492,443	-
8	All 12 Hour On-Peak Time-of-Day kVA (Per kVA)	$0	216,386	$0			
9	All 8 Hour On-Peak Time-of-Day kVA (Per kVA)	$0	3,500,687	$0			
			3,717,073	$0	$0	3,717,073	-
	ENERGY CHARGES						
10	12 Hour On Peak Time-of-Day (Per KWH)	$0	229,899,993	$0			
11	12 Hour Off Peak Time-of-Day (Per KWH)	$0	243,213,227	$0			
12	8 Hour On Peak Time-of-Day (Per KWH)	$0	345,402,083	$0			
13	8 Hour Off Peak Time-of-Day (Per KWH)	$0	822,158,787	$0			
14	All KWH		1,640,674,090	$0			
15	**TOTAL BASE NORMALIZED DISTRIBUTION REVENUES**			**$2,278,934**			**$3,676,125**
16	Smart Meter Technologies Charge (Per Bill)	$2.34	252	$589	$0	252	$0
17	**TOTAL DISTRIBUTION INCLUDING RIDER CHANGES**			**$2,279,523**			**$3,676,125**
	RIDER CHARGES						
18	Energy Efficiency (Per KW PLC)	($0.02)	2,555,410	$0	($0.02)	2,555,410	$0
19	Default Service Support (Per kW NSPL)	$0.973	2,966,962	$2,885,249	$0.973	2,966,962	$2,885,249
20	Phase II Energy Efficiency (Per kW PLC)	$0.50	2,555,410	$1,277,705	$0.50	2,555,410	$1,277,705
21	NUG	$0.00045	1,640,674,090	$665,571	$0.00045	1,640,674,090	$665,571
22	Consumer Education	$0	1,640,674,090	$0	$0	1,640,674,090	$0
23	Universal Service Charge	$0	0	$0	$0	0	$0
24	Hourly Priced Generation	$0.04277	1,640,674,090	$70,171,631	$0.04277	1,640,674,090	$70,171,631
25	Solar Photovoltaic Requirements Charge	$0.00022	1,640,674,090	$365,257	$0.00022	1,640,674,090	$365,257
26	STAS	-0.29%		$0	0%		$0
27	Total Energy and Revenue		1,640,674,090	**$77,644,936**		1,640,674,090	**$79,041,538**
28	Avg rate per kWh			$0.04733			$0.04818
29	Proposed Increase						$1,396,602
30	Percent Increase						1.80%

Metropolitan Edison Company
Rate QF - Qualifying Facilities
Revenue Effects of Proposed Rates - FTY 4/30/16

Line No.		Tariff 51, Supplement No, 44 Current Rate (1)	Billing Units (2)	Billed Revenue (3)	Tariff 52 Proposed Rate (4)	Billing Units (5)	Proposed Revenue (6)=(4)x(5)
	DISTRIBUTION CHARGES						
	CUSTOMER CHARGES						
1	QF	$79.28	48	$3,805	$79.28	48	$3,805
	DEMAND CHARGES						
2	QF Backup Secondary KW	2.27	-	$0	$2.72	-	$0
3	QF Maint Secondary KW	1.62	0		$2.18	-	$0
4	QF Backup Primary KW	0.92	16,200	$14,904	$2.51	16,200	$40,662
5	QF Maint Primary KW	0.67	0		$2.01	-	$0
6	QF Backup Transmission KW	$0.16	697,200	$111,552	$0.54	697,200	$376,488
7	QF Maint Transmission KW	$0.16	0	$0	$0.43	-	$0
8	**TOTAL BASE NORMALIZED DISTRIBUTION REVENUES**			**$130,261**			**$420,955**
9	STAS	-0.29%		$0	0%		$0
10	Total Energy and Revenue		0	$130,261		0	$420,955
11	Avg rate per kWh			$0.00000			$0.00000
12	Proposed Increase						$290,694
13	Percent Increase						223.16%

Metropolitan Edison Company
Rate MS - Municipal Service
Revenue Effects of Proposed Rates - FTY 4/30/16

Line No.		Tariff 51, Supplement No, 44 Current Rate (1)	Billing Units (2)	Billed Revenue (3)	Tariff 52 Proposed Rate (4)	Billing Units (5)	Proposed Revenue (6)=(4)x(5)
	DISTRIBUTION CHARGES						
	CUSTOMER CHARGES						
1	MS	$24.82	1,596	$39,616	$34.34	1,596	54,807
	DEMAND CHARGES						
2	All rKVA	$0	19,185	$0	$0	19,185	-
3	All kW	$0	77,316	$0	$0	77,316	-
	ENERGY CHARGES						
4	All KWH	$0.02674	16,237,695	$434,229	$0.04448	16,237,695	722,253
5	**TOTAL BASE NORMALIZED DISTRIBUTION REVENUES**			**$473,845**			**$777,060**
6	Smart Meter Technologies Charge (Per Bill)	$3.32	1,596	$5,298	$0	1,596	$0
7	**TOTAL DISTRIBUTION INCLUDING RIDER CHANGES**			**$479,143**			**$777,060**
	RIDER CHARGES						
8	NUG	($0.00002)	16,237,695	$17,164	($0.00002)	16,237,695	$17,164
9	Consumer Education	$0.00003	16,237,695	$0	$0.00003	16,237,695	$0
10	Energy Efficiency and Conservation Charge	$0.00108	16,237,695	$0	$0.00108	16,237,695	$0
11	Default Service Support Charge	$0.00236	16,237,695	$99,982	$0.00236	16,237,695	$99,982
12	Universal Service Charge	$0	0	$0	$0	0	$0
13	Solar Photovoltaic Requirements Charge	$0.00022	16,237,695	$9,417	$0.00022	16,237,695	$9,417
14	Phase II Energy Efficiency and Conservation Charge	$0.00103	16,237,695	$43,692	$0.00103	16,237,695	$43,692
15	PTC*	$0.08048	16,237,695	$1,306,810	$0.08048	16,237,695	$1,306,810
16	STAS	-0.29%		$0	0%		$0
17	Total Energy and Revenue		16,237,695	**$1,956,208**		16,237,695	**$2,254,125**
18	Avg rate per kWh			$0.12047			$0.13882
19	Proposed Increase						$297,917
20	Percent Increase						15.23%

Metropolitan Edison Company
Outdoor Area Lighting Service
Revenue Effects of Proposed Rates - FTY 4/30/16

Line No.		Tariff 51, Supplement No. 44 Current Rate (1)	Billing Units (2)	Billed Revenue (3)	Tariff 52 Proposed Rate (4)	Billing Units (5)	Proposed Revenue (6)=(4)x(5)
	LAMPS						
1	175 W MERCURY VAPOR	$4.67	30,921	$ 144,401	$ 6.26	30,921	193,574
2	100 W SODIUM VAPOR	$13.66	28,660	$ 391,498	$ 18.31	28,660	524,815
3	250 W SODIUM VAPOR	$7.40	7,003	$ 51,822	$ 9.92	7,003	69,469
4	400 W SODIUM VAPOR	$4.76	11,768	$ 56,016	$ 6.38	11,768	75,091
	POLES						
5	POLE CHARGE	$5.16	4,784	$ 24,685	$ 6.92	4,784	33,091
6	**TOTAL BASE NORMALIZED DISTRIBUTION REVENUES**			**$ 668,422**			**$ 896,040**
	RIDER CHARGES						
7	NUG	($0.00002)	6,026,199	$1,633	($0.00002)	6,026,199	$1,633
8	Consumer Education	$0.00003	6,026,199	$0	$0.00003	6,026,199	$0
9	Energy Efficiency and Conservation Charge	($0.00003)	6,026,199	$0	($0.00003)	6,026,199	$0
10	Default Service Support Charge	$0.00193	6,026,199	$7,767	$0.00193	6,026,199	$7,767
11	Universal Service Charge	$0	0	$0	$0	0	$0
12	Solar Photovoltaic Requirements Charge	$0.00022	6,026,199	$1,331	$0.00022	6,026,199	$1,331
13	Phase II Energy Efficiency and Conservation Charge	$0.00185	6,026,199	$7,468	$0.00185	6,026,199	$7,468
14	PTC*	$0.08048	6,026,199	$484,988	$0.08048	6,026,199	$484,988
15	STAS	-0.29%		$0	0%		$0
16	Total Revenue			**$ 1,171,609**			**$ 1,399,227**
17	Proposed Increase						$227,618
18	Percent Increase						19.43%

Metropolitan Edison Company
Street Lighting Service
Revenue Effects of Proposed Rates - FTY 4/30/16

Line No.		Tariff 51, Supplement No, 44 Current Rate (1)	Billing Units (2)	Billed Revenue (3)	Tariff 52 Proposed Rate (4)	Billing Units (5)	Proposed Revenue (6)=(4)x(5)
	SODIUM VAPOR						
1	70 WATTS	$5.74	43,943	$252,233	$ 6.26	43,943	275,083
2	100 WATTS	$5.62	215,807	$1,212,836	$ 6.13	215,807	1,322,897
3	150 WATTS	$5.54	122,895	$680,839	$ 6.04	122,895	742,286
4	200 WATTS	$5.20	264	$1,373	$ 5.67	264	1,497
5	250 WATTS	$5.89	53,238	$313,572	$ 6.43	53,238	342,320
6	400 WATTS	$5.77	12,846	$74,121	$ 6.29	12,846	80,801
7	800 WATTS	$5.54	-	$0	$ 6.04	-	-
	MERCURY VAPOR						
8	100 WATTS	$5.81	481	$2,795	$ 6.34	481	3,050
9	175 WATTS	$5.63	7,335	$41,296	$ 6.14	7,335	45,037
10	250 WATTS	$5.37	1,018	$5,467	$ 5.86	1,018	5,965
11	400 WATTS	$4.81	2,239	$10,770	$ 5.25	2,239	11,755
12	1000 WATTS	$3.67	19	$70	$ 4.02	19	76
	INCANDESCENT						
13	105 WATTS	$5.72	708	$4,050	$ 6.24	708	4,418
14	205 WATTS	$5.44	48	$261	$ 5.93	48	285
15	327 WATTS	$5.09	-	$0	$ 5.55	-	-
16	860 WATTS	$3.80	-	$0	$ 4.15	-	-
	METAL HALIDE				$ -		
17	175 WATTS	$5.82	1,416	$8,241	$ 6.35	1,416	8,992
18	250 WATTS	$5.82	1,056	$6,146	$ 6.35	1,056	6,706
19	400 WATTS	$5.70	4,392	$25,034	$ 6.22	4,392	27,318
20	**OVERHEAD ALT. TECHNOLOGY LIGHTING**	$5.62	6,324	$35,541	$ 6.13	6,324	38,766
	POST TOP INCANDESENT						
21	2,500 LUMENS	$40.30	408	$16,442	$ 43.96	408	17,936
22	6,000 LUMENS	$31.79	-	$0	$ 34.68	-	-
	COMPANY O&M OF CONVENTIONAL LUMIN.						
23	SODIUM VAPOR LAMPS	$2.03	343,189	$696,674	$ 2.21	343,189	758,448
24	MERCURY VAPOR LAMPS	$0.83	4,727	$3,923	$ 0.91	4,727	4,302
25	INCANDESCENT LAMPS	$2.27	708	$1,607	$ 2.48	708	1,756
	COMPANY OWNERSHIP OF CONVENTIONAL LUM. FACILITIES						
26	CHARGES PER MONTH PER LIGHT	$1.94	340,176	$659,941	$ 2.12	340,176	721,173
27	CHARGES PER MONTH PER POLE	$8.09	1,488	$12,038	$ 8.83	1,488	13,139
	UNDERGROUND FEED TO ST LIGHTS						
	DEMAND AND ENERGY/ LAMP SIZE						
	SODIUM VAPOR						
28	70 WATTS	$0.07	4,560	$319	$ 0.08	4,560	365
29	100 WATTS	$0.11	43,839	$4,822	$ 0.12	43,839	5,261
30	150 WATTS	$0.16	33,351	$5,336	$ 0.17	33,351	5,670
31	250 WATTS	$0.27	15,748	$4,252	$ 0.29	15,748	4,567
32	400 WATTS	$0.43	6,063	$2,607	$ 0.47	6,063	2,850
33	800 WATTS	$0.85	-	$0	$ 0.93	-	-

Metropolitan Edison Company
Street Lighting Service
Revenue Effects of Proposed Rates - FTY 4/30/16

		Tariff 51, Supplement No, 44			Tariff 52		
		Current Rate	Billing Units	Billed Revenue	Proposed Rate	Billing Units	Proposed Revenue
		(1)	(2)	(3)	(4)	(5)	(6)=(4)x(5)
	MERCURY VAPOR						
34	100 WATTS	$0.11	-	$0	$ 0.12	-	-
35	175 WATTS	$0.19	4,005	$761	$ 0.21	4,005	841
36	250 WATTS	$0.27	574	$155	$ 0.29	574	166
37	400 WATTS	$0.43	1,748	$752	$ 0.47	1,748	822
38	700 WATTS	$0.74	-	$0	$ 0.81	-	-
39	800 WATTS	$0.85	-	$0	$ 0.93	-	-
40	1000 WATTS	$1.06	9	$10	$ 1.21	9	11
	INCANDESCENT						
41	105 WATTS	$0.12	-	$0	$ 0.13	-	-
42	205 WATTS	$0.22	-	$0	$ 0.24	-	-
43	327 WATTS	$0.35	-	$0	$ 0.38	-	-
44	448 WATTS	$0.48	-	$0	$ 0.52	-	-
45	690 WATTS	$0.73	-	$0	$ 0.80	-	-
46	860 WATTS	$0.92	-	$0	$ 1.00	-	-
47	1720 WATTS	$1.83	-	$0	$ 2.00	-	-
	METAL HALIDE						
48	175 WATTS	$0.19	1,416	$269	$ 0.21	1,416	297
49	250 WATTS	$0.27	1,056	$285	$ 0.29	1,056	306
50	400 WATTS	$0.43	4,392	$1,889	$ 0.47	4,392	2,064
	PROVISION C MONTHLY MINUMUM CHARGE						
51	ALL FIXTURES	$0.11	116,760	$12,844	$ 0.12	116,760	14,011
	COMPANY O&M OF CONVENTIONAL LUMIN.						
52	SODIUM VAPOR LAMPS	$2.42	90,568	$219,175	$ 2.64	90,568	239,100
53	MERCURY VAPOR LAMPS	$1.37	6,188	$8,478	$ 1.49	6,188	9,220
54	INCANDESCENT LAMPS	$2.38	-	$0	$ 2.60	-	-
	COMPANY OWNERSHIP OF ORNAMENTAL LUMINAIRE						
55	CHARGES PER LIGHT	$4.60	25,104	$115,478	$ 5.02	25,104	126,022
	COMPANY OWNERSHIP OF ORNAMENTAL STANDARDS						
56	STANDARD MONTHLY CHARGE	$8.68	23,160	$201,029	$ 9.47	23,160	219,325
57	CONVERSIONS	$2.93	-	$0	$ 3.20	-	-
58	**UNDERGROUND ALT. TECHNOLOGY LIGHTING**						
59	MINIMUM FIXUTURE CHARGE	$0.11	1,740	$191	$ 0.12	1,740	209
60	KWH CHARGE	$0.002	109,250	$219	$ 0.00218		-
61	**TOTAL BASE NORMALIZED DISTRIBUTION REVENUES**			**$4,644,141**			**$5,065,113**
	RIDER CHARGES						
62	NUG	($0.00002)	28,841,545	$11,658	($0.00002)	28,841,545	$11,658
63	Consumer Education	$0.00003	28,841,545	$0	$0.00003	28,841,545	$0
64	Energy Efficiency and Conservation Charge	$0.00313	28,841,545	$0	$0.00313	28,841,545	$0
65	Default Service Support Charge	$0.00193	28,841,545	$55,519	$0.00193	28,841,545	$55,519
66	Universal Service Charge	$0.00	0	$0	$0.00	-	$0

Metropolitan Edison Company
Street Lighting Service
Revenue Effects of Proposed Rates - FTY 4/30/16

		Tariff 51, Supplement No, 44			Tariff 52		
		Current Rate	Billing Units	Billed Revenue	Proposed Rate	Billing Units	Proposed Revenue
		(1)	(2)	(3)	(4)	(5)	(6)=(4)x(5)
67	Solar Photovoltaic Requirements Charge	$0.00022	28,841,545	$6,403	$0.00022	28,841,545	$6,403
68	Phase II Energy Efficiency and Conservation Charge	$0.00101	28,841,545	$29,129	$0.00101	28,841,545	$29,129
69	PTC*	$0.08048	28,841,545	$2,321,168	$0.08048	28,841,545	$2,321,168
70	STAS	-0.29%		$0	0%		$0
71	Total Revenue			**$7,068,018**			**$7,488,990**
72	Proposed Increase						$420,972
73	Percent Increase						5.96%

Metropolitan Edison Company
Borderline Service
Revenue Effects of Proposed Rates - FTY 4/30/16

Line No.		Tariff 51, Supplement No, 44			Tariff 52		
		Current Rate (1)	Billing Units (2)	Billed Revenue (3)	Proposed Rate (4)	Billing Units (5)	Proposed Revenue (6)=(4)x(5)
	DISTRIBUTION CHARGES						
	CUSTOMER CHARGES						
	ENERGY CHARGES						
1	All kWh	$0.01409	989,773	$13,946	$0.02251	989,773	$22,280
2	Company Investment Charges	$0	0	$7,712	$0	0	12,318
3	**TOTAL DISTRIBUTION**			**$21,658**			**$34,598**
	RIDER CHARGES						
4	NUG Charge	($0.00002)	989,773	$28	($0.00002)	989,773	$28
5	Default Service Support Charge	$0.00234	989,773	$168	$0.00234	989,773	$168
6	PTC*	$0.08048	989,773	$79,657	$0.08048	989,773	$79,657
7	Solar Photovoltaic Requirements Charge	$0.00022	989,773	$16	$0.00022	989,773	$16
8	STAS	-0.29%		$0	0%	0	$0
9	Total Energy and Revenue		989,773	**$101,527**		989,773	**$114,467**
10	Avg rate per kWh			$0.10258			$0.11565
11	Proposed Increase						$12,940
12	Percent Increase						12.75%

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE RS

ENERGY USAGE																		
All kWh	0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000		
Total Energy Usage	0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000		
UNBUNDLED RATES - CURRENT																		
NUG Charge																		
All kWh @ 0.015 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75		
Distribution																		
Distribution Charge @ $8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11		
All kWh @ 2.328 ¢/kWh	$ -	$ 1.16	$ 2.33	$ 5.82	$ 11.64	$ 17.46	$ 20.95	$ 23.28	$ 34.92	$ 46.56	$ 58.20	$ 69.84	$ 81.48	$ 93.12	$ 104.76	$ 116.40		
Sub-Total	$ 8.11	$ 9.27	$ 10.44	$ 13.93	$ 19.75	$ 25.57	$ 29.06	$ 31.39	$ 43.03	$ 54.67	$ 66.31	$ 77.95	$ 89.59	$ 101.23	$ 112.87	$ 124.51		
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.26	$ 0.53	$ 1.32	$ 2.65	$ 3.97	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45		
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Phase II Energy Efficiency Charge @ 0.316 ¢/kWh	$ -	$ 0.16	$ 0.32	$ 0.79	$ 1.58	$ 2.37	$ 2.84	$ 3.16	$ 4.74	$ 6.32	$ 7.90	$ 9.48	$ 11.06	$ 12.64	$ 14.22	$ 15.80		
Smart Meter Charge @ $2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34		
Default Service Support Charge @ 0.401 ¢/kWh	$ -	$ 0.20	$ 0.40	$ 1.00	$ 2.01	$ 3.01	$ 3.61	$ 4.01	$ 6.02	$ 8.02	$ 10.03	$ 12.03	$ 14.04	$ 16.04	$ 18.05	$ 20.05		
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.06	$ 0.11	$ 0.17	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10		
Sub-Total	$ 2.34	$ 2.97	$ 3.61	$ 5.51	$ 8.68	$ 11.85	$ 13.75	$ 15.02	$ 21.36	$ 27.70	$ 34.04	$ 40.38	$ 46.72	$ 53.06	$ 59.40	$ 65.74		
PTC Charge																		
All kWh @$ 0.08198 /kWh	$ -	$ 4.10	$ 8.20	$ 20.50	$ 40.99	$ 61.49	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90		
Sub Total	$ 10.45	$ 16.35	$ 22.26	$ 39.97	$ 69.50	$ 99.02	$ 116.73	$ 128.54	$ 187.59	$ 246.63	$ 305.68	$ 364.72	$ 423.77	$ 482.81	$ 541.86	$ 600.90		
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Bill	**$ 10.45**	**$ 16.35**	**$ 22.26**	**$ 39.97**	**$ 69.50**	**$ 99.02**	**$ 116.73**	**$ 128.54**	**$ 187.59**	**$ 246.63**	**$ 305.68**	**$ 364.72**	**$ 423.77**	**$ 482.81**	**$ 541.86**	**$ 600.90**		
UNBUNDLED RATES - PROPOSED																		
NUG Charge																		
All kWh @ 0.015 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75		
Distribution																		
Distribution Charge @ $13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29		
All kWh @ 4.103 ¢/kWh	$ -	$ 2.05	$ 4.10	$ 10.26	$ 20.52	$ 30.77	$ 36.93	$ 41.03	$ 61.55	$ 82.06	$ 102.58	$ 123.09	$ 143.61	$ 164.12	$ 184.64	$ 205.15		
Sub-Total	$ 13.29	$ 15.34	$ 17.39	$ 23.55	$ 33.81	$ 44.06	$ 50.22	$ 54.32	$ 74.84	$ 95.35	$ 115.87	$ 136.38	$ 156.90	$ 177.41	$ 197.93	$ 218.44		
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.26	$ 0.53	$ 1.32	$ 2.65	$ 3.97	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45		
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Phase II Energy Efficiency Charge @ 0.316 ¢/kWh	$ -	$ 0.16	$ 0.32	$ 0.79	$ 1.58	$ 2.37	$ 2.84	$ 3.16	$ 4.74	$ 6.32	$ 7.90	$ 9.48	$ 11.06	$ 12.64	$ 14.22	$ 15.80		
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Default Service Support Charge @ 0.401 ¢/kWh	$ -	$ 0.20	$ 0.40	$ 1.00	$ 2.01	$ 3.01	$ 3.61	$ 4.01	$ 6.02	$ 8.02	$ 10.03	$ 12.03	$ 14.04	$ 16.04	$ 18.05	$ 20.05		
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.06	$ 0.11	$ 0.17	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10		
	$ -	$ 0.63	$ 1.27	$ 3.17	$ 6.34	$ 9.51	$ 11.41	$ 12.68	$ 19.02	$ 25.36	$ 31.70	$ 38.04	$ 44.38	$ 50.72	$ 57.06	$ 63.40		
PTC Charge																		
All kWh @ $ 0.08198 /kWh	$ -	$ 4.10	$ 8.20	$ 20.50	$ 40.99	$ 61.49	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90		
Sub Total	$ 13.29	$ 20.08	$ 26.87	$ 47.25	$ 81.21	$ 115.17	$ 135.55	$ 149.13	$ 217.05	$ 284.97	$ 352.89	$ 420.81	$ 488.73	$ 556.65	$ 624.57	$ 692.49		
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Total Bill	**$ 13.29**	**$ 20.08**	**$ 26.87**	**$ 47.25**	**$ 81.21**	**$ 115.17**	**$ 135.55**	**$ 149.13**	**$ 217.05**	**$ 284.97**	**$ 352.89**	**$ 420.81**	**$ 488.73**	**$ 556.65**	**$ 624.57**	**$ 692.49**		
% Increase	**27.18%**	**22.79%**	**20.73%**	**18.21%**	**16.86%**	**16.31%**	**16.12%**	**16.02%**	**15.71%**	**15.55%**	**15.45%**	**15.38%**	**15.33%**	**15.29%**	**15.27%**	**15.24%**		

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE RT vs RATE RS
On Peak Usage at 33%

ENERGY USAGE																	
Total Energy Usage	0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000
On Peak	0	17	33	83	165	248	297	330	495	660	825	990	1,155	1,320	1,485	1,650
Off Peak	0	34	67	168	335	503	603	670	1,005	1,340	1,675	2,010	2,345	2,680	3,015	3,350
Total Energy Usage	0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000

UNBUNDLED RATES - CURRENT

NUG Charge																	
All kWh @ 0.015 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75
Distribution																	
Distribution Charge @ $11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00
On Peak @ 5.043 ¢/kWh	$ -	$ 0.83	$ 1.66	$ 4.16	$ 8.32	$ 12.48	$ 14.98	$ 16.64	$ 24.96	$ 33.28	$ 41.60	$ 49.93	$ 58.25	$ 66.57	$ 74.89	$ 83.21
Off Peak @ 0.283 ¢/kWh	$ -	$ 0.09	$ 0.19	$ 0.47	$ 0.95	$ 1.42	$ 1.71	$ 1.90	$ 2.84	$ 3.79	$ 4.74	$ 5.69	$ 6.64	$ 7.58	$ 8.53	$ 9.48
Sub-Total	$ 11.00	$ 11.93	$ 12.85	$ 15.63	$ 20.27	$ 24.90	$ 27.68	$ 29.54	$ 38.81	$ 48.08	$ 57.35	$ 66.61	$ 75.88	$ 85.15	$ 94.42	$ 103.69
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.26	$ 0.53	$ 1.32	$ 2.65	$ 3.97	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.316 ¢/kWh	$ -	$ 0.16	$ 0.32	$ 0.79	$ 1.58	$ 2.37	$ 2.84	$ 3.16	$ 4.74	$ 6.32	$ 7.90	$ 9.48	$ 11.06	$ 12.64	$ 14.22	$ 15.80
Smart Meter Charge @ $2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33
Default Service Support Charge @ 0.377 ¢/kWh	$ -	$ 0.19	$ 0.38	$ 0.94	$ 1.89	$ 2.83	$ 3.39	$ 3.77	$ 5.66	$ 7.54	$ 9.43	$ 11.31	$ 13.20	$ 15.08	$ 16.97	$ 18.85
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.06	$ 0.11	$ 0.17	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10
Sub-Total	$ 2.33	$ 2.95	$ 3.57	$ 5.44	$ 8.55	$ 11.66	$ 13.53	$ 14.77	$ 20.99	$ 27.21	$ 33.43	$ 39.65	$ 45.87	$ 52.09	$ 58.31	$ 64.53
PTC Charge																	
All kWh @ $ 0.08198 /kWh	$ -	$ 4.10	$ 8.20	$ 20.50	$ 40.99	$ 61.49	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90
Sub Total	$ 13.33	$ 18.99	$ 24.64	$ 41.61	$ 69.88	$ 98.16	$ 115.13	$ 126.44	$ 182.99	$ 239.55	$ 296.10	$ 352.65	$ 409.21	$ 465.76	$ 522.32	$ 578.87
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 13.33**	**$ 18.99**	**$ 24.64**	**$ 41.61**	**$ 69.88**	**$ 98.16**	**$ 115.13**	**$ 126.44**	**$ 182.99**	**$ 239.55**	**$ 296.10**	**$ 352.65**	**$ 409.21**	**$ 465.76**	**$ 522.32**	**$ 578.87**

UNBUNDLED RATES - PROPOSED

NUG Charge																	
All kWh @ 0.015 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75
Distribution																	
Distribution Charge @ $13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29
All kWh @ 4.103 ¢/kWh	$ -	$ 2.05	$ 4.10	$ 10.26	$ 20.52	$ 30.77	$ 36.93	$ 41.03	$ 61.55	$ 82.06	$ 102.58	$ 123.09	$ 143.61	$ 164.12	$ 184.64	$ 205.15
Sub-Total	$ 13.29	$ 15.34	$ 17.39	$ 23.55	$ 33.81	$ 44.06	$ 50.22	$ 54.32	$ 74.84	$ 95.35	$ 115.87	$ 136.38	$ 156.90	$ 177.41	$ 197.93	$ 218.44
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.26	$ 0.53	$ 1.32	$ 2.65	$ 3.97	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.316 ¢/kWh	$ -	$ 0.16	$ 0.32	$ 0.79	$ 1.58	$ 2.37	$ 2.84	$ 3.16	$ 4.74	$ 6.32	$ 7.90	$ 9.48	$ 11.06	$ 12.64	$ 14.22	$ 15.80
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @ 0.401 ¢/kWh	$ -	$ 0.20	$ 0.40	$ 1.00	$ 2.01	$ 3.01	$ 3.61	$ 4.01	$ 6.02	$ 8.02	$ 10.03	$ 12.03	$ 14.04	$ 16.04	$ 18.05	$ 20.05
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.06	$ 0.11	$ 0.17	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10
	$ -	$ 0.63	$ 1.27	$ 3.17	$ 6.34	$ 9.51	$ 11.41	$ 12.68	$ 19.02	$ 25.36	$ 31.70	$ 38.04	$ 44.38	$ 50.72	$ 57.06	$ 63.40
PTC Charge																	
All kWh @ $ 0.08198 /kWh	$ -	$ 4.10	$ 8.20	$ 20.50	$ 40.99	$ 61.49	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90
Sub Total	$ 13.29	$ 20.08	$ 26.87	$ 47.25	$ 81.21	$ 115.17	$ 135.55	$ 149.13	$ 217.05	$ 284.97	$ 352.89	$ 420.81	$ 488.73	$ 556.65	$ 624.57	$ 692.49
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 13.29**	**$ 20.08**	**$ 26.87**	**$ 47.25**	**$ 81.21**	**$ 115.17**	**$ 135.55**	**$ 149.13**	**$ 217.05**	**$ 284.97**	**$ 352.89**	**$ 420.81**	**$ 488.73**	**$ 556.65**	**$ 624.57**	**$ 692.49**
% Increase	**-0.30%**	**5.78%**	**9.06%**	**13.56%**	**16.21%**	**17.33%**	**17.74%**	**17.95%**	**18.61%**	**18.96%**	**19.18%**	**19.33%**	**19.43%**	**19.51%**	**19.58%**	**19.63%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE RT SUMMER vs RATE RS
On Peak Usage at 38%

ENERGY USAGE																	
Total Energy Usage	0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000
On Peak	0	19	38	95	190	285	342	380	570	760	950	1,140	1,330	1,520	1,710	1,900
Off Peak	0	31	62	155	310	465	558	620	930	1,240	1,550	1,860	2,170	2,480	2,790	3,100
Total Energy Usage	0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000

UNBUNDLED RATES - CURRENT

NUG Charge																	
All kWh @ 0.015 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75
Distribution																	
Distribution Charge @ $11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00
On Peak @ 3.526 ¢/kWh	$ -	$ 0.67	$ 1.34	$ 3.35	$ 6.70	$ 10.05	$ 12.06	$ 13.40	$ 20.10	$ 26.80	$ 33.50	$ 40.20	$ 46.90	$ 53.60	$ 60.29	$ 66.99
Off Peak @ 0.283 ¢/kWh	$ -	$ 0.09	$ 0.18	$ 0.44	$ 0.88	$ 1.32	$ 1.58	$ 1.75	$ 2.63	$ 3.51	$ 4.39	$ 5.26	$ 6.14	$ 7.02	$ 7.90	$ 8.77
Sub-Total	$ 11.00	$ 11.76	$ 12.52	$ 14.79	$ 18.58	$ 22.37	$ 24.64	$ 26.15	$ 33.73	$ 41.31	$ 48.88	$ 56.46	$ 64.04	$ 71.61	$ 79.19	$ 86.77
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.26	$ 0.53	$ 1.32	$ 2.65	$ 3.97	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.316 ¢/kWh	$ -	$ 0.16	$ 0.32	$ 0.79	$ 1.58	$ 2.37	$ 2.84	$ 3.16	$ 4.74	$ 6.32	$ 7.90	$ 9.48	$ 11.06	$ 12.64	$ 14.22	$ 15.80
Smart Meter Charge @ $2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33
Default Service Support Charge @ 0.377 ¢/kWh	$ -	$ 0.19	$ 0.38	$ 0.94	$ 1.89	$ 2.83	$ 3.39	$ 3.77	$ 5.66	$ 7.54	$ 9.43	$ 11.31	$ 13.20	$ 15.08	$ 16.97	$ 18.85
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.06	$ 0.11	$ 0.17	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10
Sub-Total	$ 2.33	$ 2.95	$ 3.57	$ 5.44	$ 8.55	$ 11.66	$ 13.53	$ 14.77	$ 20.99	$ 27.21	$ 33.43	$ 39.65	$ 45.87	$ 52.09	$ 58.31	$ 64.53
PTC Charge																	
All kWh @ $ 0.08198/kWh	$ -	$ 4.10	$ 8.20	$ 20.50	$ 40.99	$ 61.49	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90
Sub Total	$ 13.33	$ 18.82	$ 24.30	$ 40.76	$ 68.19	$ 95.62	$ 112.08	$ 123.05	$ 177.92	$ 232.78	$ 287.64	$ 342.50	$ 397.36	$ 452.22	$ 507.09	$ 561.95
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 13.33**	**$ 18.82**	**$ 24.30**	**$ 40.76**	**$ 68.19**	**$ 95.62**	**$ 112.08**	**$ 123.05**	**$ 177.92**	**$ 232.78**	**$ 287.64**	**$ 342.50**	**$ 397.36**	**$ 452.22**	**$ 507.09**	**$ 561.95**

UNBUNDLED RATES - PROPOSED

NUG Charge																	
All kWh @ 0.015 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75
Distribution																	
Distribution Charge @ $13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29
All kWh @ 4.103 ¢/kWh	$ -	$ 2.05	$ 4.10	$ 10.26	$ 20.52	$ 30.77	$ 36.93	$ 41.03	$ 61.55	$ 82.06	$ 102.58	$ 123.09	$ 143.61	$ 164.12	$ 184.64	$ 205.15
Sub-Total	$ 13.29	$ 15.34	$ 17.39	$ 23.55	$ 33.81	$ 44.06	$ 50.22	$ 54.32	$ 74.84	$ 95.35	$ 115.87	$ 136.38	$ 156.90	$ 177.41	$ 197.93	$ 218.44
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.26	$ 0.53	$ 1.32	$ 2.65	$ 3.97	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.316 ¢/kWh	$ -	$ 0.16	$ 0.32	$ 0.79	$ 1.58	$ 2.37	$ 2.84	$ 3.16	$ 4.74	$ 6.32	$ 7.90	$ 9.48	$ 11.06	$ 12.64	$ 14.22	$ 15.80
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @ 0.401 ¢/kWh	$ -	$ 0.20	$ 0.40	$ 1.00	$ 2.01	$ 3.01	$ 3.61	$ 4.01	$ 6.02	$ 8.02	$ 10.03	$ 12.03	$ 14.04	$ 16.04	$ 18.05	$ 20.05
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.06	$ 0.11	$ 0.17	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10
	$ -	$ 0.63	$ 1.27	$ 3.17	$ 6.34	$ 9.51	$ 11.41	$ 12.68	$ 19.02	$ 25.36	$ 31.70	$ 38.04	$ 44.38	$ 50.72	$ 57.06	$ 63.40
PTC Charge																	
All kWh @ $ 0.08198 /kWh	$ -	$ 4.10	$ 8.20	$ 20.50	$ 40.99	$ 61.49	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90
Sub Total	$ 13.29	$ 20.08	$ 26.87	$ 47.25	$ 81.21	$ 115.17	$ 135.55	$ 149.13	$ 217.05	$ 284.97	$ 352.89	$ 420.81	$ 488.73	$ 556.65	$ 624.57	$ 692.49
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 13.29**	**$ 20.08**	**$ 26.87**	**$ 47.25**	**$ 81.21**	**$ 115.17**	**$ 135.55**	**$ 149.13**	**$ 217.05**	**$ 284.97**	**$ 352.89**	**$ 420.81**	**$ 488.73**	**$ 556.65**	**$ 624.57**	**$ 692.49**
% Increase	**-0.30%**	**6.73%**	**10.58%**	**15.92%**	**19.09%**	**20.44%**	**20.94%**	**21.19%**	**22.00%**	**22.42%**	**22.69%**	**22.86%**	**22.99%**	**23.09%**	**23.17%**	**23.23%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE RT NON-SUMMER vs RATE RS
On Peak Usage at 33%

ENERGY USAGE																	
Total Energy Usage	0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000
On Peak	0	17	33	83	165	248	297	330	495	660	825	990	1,155	1,320	1,485	1,650
Off Peak	0	34	67	168	335	503	603	670	1,005	1,340	1,675	2,010	2,345	2,680	3,015	3,350
Total Energy Usage	0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000

UNBUNDLED RATES - CURRENT

NUG Charge																	
All kWh @ 0.015 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75
Distribution																	
Distribution Charge @ $11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00
On Peak @ 1.946 ¢/kWh	$ -	$ 0.32	$ 0.64	$ 1.61	$ 3.21	$ 4.82	$ 5.78	$ 6.42	$ 9.63	$ 12.84	$ 16.05	$ 19.27	$ 22.48	$ 25.69	$ 28.90	$ 32.11
Off Peak @ 0.283 ¢/kWh	$ -	$ 0.09	$ 0.19	$ 0.47	$ 0.95	$ 1.42	$ 1.71	$ 1.90	$ 2.84	$ 3.79	$ 4.74	$ 5.69	$ 6.64	$ 7.58	$ 8.53	$ 9.48
Sub-Total	$ 11.00	$ 11.42	$ 11.83	$ 13.08	$ 15.16	$ 17.24	$ 18.49	$ 19.32	$ 23.48	$ 27.64	$ 31.79	$ 35.95	$ 40.11	$ 44.27	$ 48.43	$ 52.59
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.26	$ 0.53	$ 1.32	$ 2.65	$ 3.97	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.316 ¢/kWh	$ -	$ 0.16	$ 0.32	$ 0.79	$ 1.58	$ 2.37	$ 2.84	$ 3.16	$ 4.74	$ 6.32	$ 7.90	$ 9.48	$ 11.06	$ 12.64	$ 14.22	$ 15.80
Smart Meter Charge @ $2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33
Default Service Support Charge @ 0.377 ¢/kWh	$ -	$ 0.19	$ 0.38	$ 0.94	$ 1.89	$ 2.83	$ 3.39	$ 3.77	$ 5.66	$ 7.54	$ 9.43	$ 11.31	$ 13.20	$ 15.08	$ 16.97	$ 18.85
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.06	$ 0.11	$ 0.17	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10
Sub-Total	$ 2.33	$ 2.95	$ 3.57	$ 5.44	$ 8.55	$ 11.66	$ 13.53	$ 14.77	$ 20.99	$ 27.21	$ 33.43	$ 39.65	$ 45.87	$ 52.09	$ 58.31	$ 64.53
PTC Charge																	
All kWh @ $ 0.08198/kWh	$ -	$ 4.10	$ 8.20	$ 20.50	$ 40.99	$ 61.49	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90
Sub Total	$ 13.33	$ 18.47	$ 23.62	$ 39.05	$ 64.77	$ 90.50	$ 105.93	$ 116.22	$ 167.66	$ 219.11	$ 270.55	$ 321.99	$ 373.44	$ 424.88	$ 476.33	$ 527.77
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 13.33**	**$ 18.47**	**$ 23.62**	**$ 39.05**	**$ 64.77**	**$ 90.50**	**$ 105.93**	**$ 116.22**	**$ 167.66**	**$ 219.11**	**$ 270.55**	**$ 321.99**	**$ 373.44**	**$ 424.88**	**$ 476.33**	**$ 527.77**

UNBUNDLED RATES - PROPOSED

NUG Charge																	
All kWh @ 0.015 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75
Distribution																	
Distribution Charge @ $13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29
All kWh @ 4.103 ¢/kWh	$ -	$ 2.05	$ 4.10	$ 10.26	$ 20.52	$ 30.77	$ 36.93	$ 41.03	$ 61.55	$ 82.06	$ 102.58	$ 123.09	$ 143.61	$ 164.12	$ 184.64	$ 205.15
Sub-Total	$ 13.29	$ 15.34	$ 17.39	$ 23.55	$ 33.81	$ 44.06	$ 50.22	$ 54.32	$ 74.84	$ 95.35	$ 115.87	$ 136.38	$ 156.90	$ 177.41	$ 197.93	$ 218.44
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.26	$ 0.53	$ 1.32	$ 2.65	$ 3.97	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.316 ¢/kWh	$ -	$ 0.16	$ 0.32	$ 0.79	$ 1.58	$ 2.37	$ 2.84	$ 3.16	$ 4.74	$ 6.32	$ 7.90	$ 9.48	$ 11.06	$ 12.64	$ 14.22	$ 15.80
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @ 0.401 ¢/kWh	$ -	$ 0.20	$ 0.40	$ 1.00	$ 2.01	$ 3.01	$ 3.61	$ 4.01	$ 6.02	$ 8.02	$ 10.03	$ 12.03	$ 14.04	$ 16.04	$ 18.05	$ 20.05
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.06	$ 0.11	$ 0.17	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10
	$ -	$ 0.63	$ 1.27	$ 3.17	$ 6.34	$ 9.51	$ 11.41	$ 12.68	$ 19.02	$ 25.36	$ 31.70	$ 38.04	$ 44.38	$ 50.72	$ 57.06	$ 63.40
PTC Charge																	
All kWh @ $ 0.08198 /kWh	$ -	$ 4.10	$ 8.20	$ 20.50	$ 40.99	$ 61.49	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90
Sub Total	$ 13.29	$ 20.08	$ 26.87	$ 47.25	$ 81.21	$ 115.17	$ 135.55	$ 149.13	$ 217.05	$ 284.97	$ 352.89	$ 420.81	$ 488.73	$ 556.65	$ 624.57	$ 692.49
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 13.29**	**$ 20.08**	**$ 26.87**	**$ 47.25**	**$ 81.21**	**$ 115.17**	**$ 135.55**	**$ 149.13**	**$ 217.05**	**$ 284.97**	**$ 352.89**	**$ 420.81**	**$ 488.73**	**$ 556.65**	**$ 624.57**	**$ 692.49**
% Increase	**-0.30%**	**8.70%**	**13.78%**	**20.99%**	**25.37%**	**27.27%**	**27.96%**	**28.32%**	**29.46%**	**30.06%**	**30.43%**	**30.69%**	**30.87%**	**31.01%**	**31.12%**	**31.21%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS-V

ENERGY USAGE

	0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000
All kWh	0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000
Total Energy Usage	0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000

UNBUNDLED RATES - CURRENT

NUG Charge																
All kWh @ 0.015 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75
Distribution																
Distribution Charge @ $8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11	$ 8.11
All kWh @ 2.328 ¢/kWh	$ -	$ 1.16	$ 2.33	$ 5.82	$ 11.64	$ 17.46	$ 20.95	$ 23.28	$ 34.92	$ 46.56	$ 58.20	$ 69.84	$ 81.48	$ 93.12	$ 104.76	$ 116.40
Sub-Total	$ 8.11	$ 9.27	$ 10.44	$ 13.93	$ 19.75	$ 25.57	$ 29.06	$ 31.39	$ 43.03	$ 54.67	$ 66.31	$ 77.95	$ 89.59	$ 101.23	$ 112.87	$ 124.51
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.26	$ 0.53	$ 1.32	$ 2.65	$ 3.97	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.103 ¢/kWh	$ -	$ 0.05	$ 0.10	$ 0.26	$ 0.52	$ 0.77	$ 0.93	$ 1.03	$ 1.55	$ 2.06	$ 2.58	$ 3.09	$ 3.61	$ 4.12	$ 4.64	$ 5.15
Smart Meter Charge @ $2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33
Default Service Support Charge @ 0.401 ¢/kWh	$ -	$ 0.20	$ 0.40	$ 1.00	$ 2.01	$ 3.01	$ 3.61	$ 4.01	$ 6.02	$ 8.02	$ 10.03	$ 12.03	$ 14.04	$ 16.04	$ 18.05	$ 20.05
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.06	$ 0.11	$ 0.17	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10
Sub-Total	$ 2.33	$ 2.86	$ 3.39	$ 4.97	$ 7.61	$ 10.24	$ 11.83	$ 12.88	$ 18.16	$ 23.43	$ 28.71	$ 33.98	$ 39.26	$ 44.53	$ 49.81	$ 55.08
PTC Charge																
All kWh @ $ 0.08198 /kWh	$ -	$ 4.10	$ 8.20	$ 20.50	$ 40.99	$ 61.49	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90
Sub Total	$ 10.44	$ 16.24	$ 22.04	$ 39.43	$ 68.42	$ 97.41	$ 114.80	$ 126.40	$ 184.38	$ 242.36	$ 300.34	$ 358.32	$ 416.30	$ 474.28	$ 532.26	$ 590.24
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 10.44**	**$ 16.24**	**$ 22.04**	**$ 39.43**	**$ 68.42**	**$ 97.41**	**$ 114.80**	**$ 126.40**	**$ 184.38**	**$ 242.36**	**$ 300.34**	**$ 358.32**	**$ 416.30**	**$ 474.28**	**$ 532.26**	**$ 590.24**

UNBUNDLED RATES - PROPOSED

NUG Charge																
All kWh @ 0.015 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75
Distribution																
Distribution Charge @ $13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29
All kWh @ 4.103 ¢/kWh	$ -	$ 2.05	$ 4.10	$ 10.26	$ 20.52	$ 30.77	$ 36.93	$ 41.03	$ 61.55	$ 82.06	$ 102.58	$ 123.09	$ 143.61	$ 164.12	$ 184.64	$ 205.15
Sub-Total	$ 13.29	$ 15.34	$ 17.39	$ 23.55	$ 33.81	$ 44.06	$ 50.22	$ 54.32	$ 74.84	$ 95.35	$ 115.87	$ 136.38	$ 156.90	$ 177.41	$ 197.93	$ 218.44
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.26	$ 0.53	$ 1.32	$ 2.65	$ 3.97	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.103 ¢/kWh	$ -	$ 0.05	$ 0.10	$ 0.26	$ 0.52	$ 0.77	$ 0.93	$ 1.03	$ 1.55	$ 2.06	$ 2.58	$ 3.09	$ 3.61	$ 4.12	$ 4.64	$ 5.15
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @ 0.401 ¢/kWh	$ -	$ 0.20	$ 0.40	$ 1.00	$ 2.01	$ 3.01	$ 3.61	$ 4.01	$ 6.02	$ 8.02	$ 10.03	$ 12.03	$ 14.04	$ 16.04	$ 18.05	$ 20.05
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.06	$ 0.11	$ 0.17	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10
Sub-Total	$ -	$ 0.53	$ 1.06	$ 2.64	$ 5.28	$ 7.91	$ 9.50	$ 10.55	$ 15.83	$ 21.10	$ 26.38	$ 31.65	$ 36.93	$ 42.20	$ 47.48	$ 52.75
PTC Charge																
All kWh @ $ 0.08198 /kWh	$ -	$ 4.10	$ 8.20	$ 20.50	$ 40.99	$ 61.49	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90
Sub Total	$ 13.29	$ 19.98	$ 26.66	$ 46.72	$ 80.15	$ 113.57	$ 133.63	$ 147.00	$ 213.86	$ 280.71	$ 347.57	$ 414.42	$ 481.28	$ 548.13	$ 614.99	$ 681.84
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 13.29**	**$ 19.98**	**$ 26.66**	**$ 46.72**	**$ 80.15**	**$ 113.57**	**$ 133.63**	**$ 147.00**	**$ 213.86**	**$ 280.71**	**$ 347.57**	**$ 414.42**	**$ 481.28**	**$ 548.13**	**$ 614.99**	**$ 681.84**
% Increase	**27.30%**	**23.02%**	**20.99%**	**18.48%**	**17.14%**	**16.59%**	**16.40%**	**16.30%**	**15.99%**	**15.82%**	**15.72%**	**15.66%**	**15.61%**	**15.57%**	**15.54%**	**15.52%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS-V SUMMER vs RATE GS-V

ENERGY USAGE																	
Total Energy Usage	0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000
On Peak	0	17	33	83	165	248	297	330	495	660	825	990	1,155	1,320	1,485	1,650
Off Peak	0	34	67	168	335	503	603	670	1,005	1,340	1,675	2,010	2,345	2,680	3,015	3,350
Total Energy Usage	0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000

UNBUNDLED RATES - CURRENT

NUG Charge																	
All kWh @ 0.015 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75
Distribution																	
Distribution Charge @ $11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00
On Peak @ 3.526 ¢/kWh	$ -	$ 0.58	$ 1.16	$ 2.91	$ 5.82	$ 8.73	$ 10.47	$ 11.64	$ 17.45	$ 23.27	$ 29.09	$ 34.91	$ 40.73	$ 46.54	$ 52.36	$ 58.18
Off Peak @ 0.283 ¢/kWh	$ -	$ 0.09	$ 0.19	$ 0.47	$ 0.95	$ 1.42	$ 1.71	$ 1.90	$ 2.84	$ 3.79	$ 4.74	$ 5.69	$ 6.64	$ 7.58	$ 8.53	$ 9.48
Sub-Total	$ 11.00	$ 11.68	$ 12.35	$ 14.38	$ 17.77	$ 21.15	$ 23.18	$ 24.53	$ 31.30	$ 38.06	$ 44.83	$ 51.60	$ 58.36	$ 65.13	$ 71.89	$ 78.66
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.26	$ 0.53	$ 1.32	$ 2.65	$ 3.97	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.103 ¢/kWh	$ -	$ 0.05	$ 0.10	$ 0.26	$ 0.52	$ 0.77	$ 0.93	$ 1.03	$ 1.55	$ 2.06	$ 2.58	$ 3.09	$ 3.61	$ 4.12	$ 4.64	$ 5.15
Smart Meter Charge @ $2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33
Default Service Support Charge @ 0.401 ¢/kWh	$ -	$ 0.20	$ 0.40	$ 1.00	$ 2.01	$ 3.01	$ 3.61	$ 4.01	$ 6.02	$ 8.02	$ 10.03	$ 12.03	$ 14.04	$ 16.04	$ 18.05	$ 20.05
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.06	$ 0.11	$ 0.17	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10
Sub-Total	$ 2.33	$ 2.86	$ 3.39	$ 4.97	$ 7.61	$ 10.24	$ 11.83	$ 12.88	$ 18.16	$ 23.43	$ 28.71	$ 33.98	$ 39.26	$ 44.53	$ 49.81	$ 55.08
PTC Charge																	
All kWh @ $ 0.08198 /kWh	$ -	$ 4.10	$ 8.20	$ 20.50	$ 40.99	$ 61.49	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90
Sub Total	$ 13.33	$ 18.64	$ 23.95	$ 39.88	$ 66.44	$ 92.99	$ 108.92	$ 119.54	$ 172.65	$ 225.75	$ 278.86	$ 331.97	$ 385.07	$ 438.18	$ 491.28	$ 544.39
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 13.33**	**$ 18.64**	**$ 23.95**	**$ 39.88**	**$ 66.44**	**$ 92.99**	**$ 108.92**	**$ 119.54**	**$ 172.65**	**$ 225.75**	**$ 278.86**	**$ 331.97**	**$ 385.07**	**$ 438.18**	**$ 491.28**	**$ 544.39**

UNBUNDLED RATES - PROPOSED

NUG Charge																	
All kWh @ 0.015 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75
Distribution																	
Distribution Charge @ $13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29
All kWh @ 4.103 ¢/kWh	$ -	$ 2.05	$ 4.10	$ 10.26	$ 20.52	$ 30.77	$ 36.93	$ 41.03	$ 61.55	$ 82.06	$ 102.58	$ 123.09	$ 143.61	$ 164.12	$ 184.64	$ 205.15
Sub-Total	$ 13.29	$ 15.34	$ 17.39	$ 23.55	$ 33.81	$ 44.06	$ 50.22	$ 54.32	$ 74.84	$ 95.35	$ 115.87	$ 136.38	$ 156.90	$ 177.41	$ 197.93	$ 218.44
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.26	$ 0.53	$ 1.32	$ 2.65	$ 3.97	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.103 ¢/kWh	$ -	$ 0.05	$ 0.10	$ 0.26	$ 0.52	$ 0.77	$ 0.93	$ 1.03	$ 1.55	$ 2.06	$ 2.58	$ 3.09	$ 3.61	$ 4.12	$ 4.64	$ 5.15
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @ 0.401 ¢/kWh	$ -	$ 0.20	$ 0.40	$ 1.00	$ 2.01	$ 3.01	$ 3.61	$ 4.01	$ 6.02	$ 8.02	$ 10.03	$ 12.03	$ 14.04	$ 16.04	$ 18.05	$ 20.05
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.01	$ 0.02	$ 0.06	$ 0.11	$ 0.17	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10
Sub-Total	$ -	$ 0.53	$ 1.06	$ 2.64	$ 5.28	$ 7.91	$ 9.50	$ 10.55	$ 15.83	$ 21.10	$ 26.38	$ 31.65	$ 36.93	$ 42.20	$ 47.48	$ 52.75
PTC Charge																	
All kWh @ $ 0.08198 /kWh	$ -	$ 4.10	$ 8.20	$ 20.50	$ 40.99	$ 61.49	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90
Sub Total	$ 13.29	$ 19.98	$ 26.66	$ 46.72	$ 80.15	$ 113.57	$ 133.63	$ 147.00	$ 213.86	$ 280.71	$ 347.57	$ 414.42	$ 481.28	$ 548.13	$ 614.99	$ 681.84
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 13.29**	**$ 19.98**	**$ 26.66**	**$ 46.72**	**$ 80.15**	**$ 113.57**	**$ 133.63**	**$ 147.00**	**$ 213.86**	**$ 280.71**	**$ 347.57**	**$ 414.42**	**$ 481.28**	**$ 548.13**	**$ 614.99**	**$ 681.84**
% Increase	**-0.30%**	**7.16%**	**11.31%**	**17.14%**	**20.63%**	**22.14%**	**22.68%**	**22.97%**	**23.87%**	**24.34%**	**24.64%**	**24.84%**	**24.98%**	**25.09%**	**25.18%**	**25.25%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS-V NON-SUMMER vs RATE GS-V

ENERGY USAGE																
Total Energy Usage	0	100	300	500	700	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000
On Peak	0	33	99	165	231	297	330	495	660	825	990	1,155	1,320	1,485	1,650
Off Peak	0	67	201	335	469	603	670	1,005	1,340	1,675	2,010	2,345	2,680	3,015	3,350
Total Energy Usage	0	100	300	500	700	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000

UNBUNDLED RATES - CURRENT

NUG Charge																
All kWh @ 0.015 ¢/kWh	$ -	$ 0.02	$ 0.05	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75	
Distribution																
Distribution Charge @ $11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	
On Peak @ 1.946 ¢/kWh	$ -	$ 0.64	$ 1.93	$ 3.21	$ 4.50	$ 5.78	$ 6.42	$ 9.63	$ 12.84	$ 16.05	$ 19.27	$ 22.48	$ 25.69	$ 28.90	$ 32.11	
Off Peak @ 0.283 ¢/kWh	$ -	$ 0.19	$ 0.57	$ 0.95	$ 1.33	$ 1.71	$ 1.90	$ 2.84	$ 3.79	$ 4.74	$ 5.69	$ 6.64	$ 7.58	$ 8.53	$ 9.48	
Sub-Total	$ 11.00	$ 11.83	$ 13.50	$ 15.16	$ 16.82	$ 18.49	$ 19.32	$ 23.48	$ 27.64	$ 31.79	$ 35.95	$ 40.11	$ 44.27	$ 48.43	$ 52.59	
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.53	$ 1.59	$ 2.65	$ 3.70	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.103 ¢/kWh	$ -	$ 0.10	$ 0.31	$ 0.52	$ 0.72	$ 0.93	$ 1.03	$ 1.55	$ 2.06	$ 2.58	$ 3.09	$ 3.61	$ 4.12	$ 4.64	$ 5.15	
Smart Meter Charge @ $2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	
Default Service Support Charge @ 0.401 ¢/kWh	$ -	$ 0.40	$ 1.20	$ 2.01	$ 2.81	$ 3.61	$ 4.01	$ 6.02	$ 8.02	$ 10.03	$ 12.03	$ 14.04	$ 16.04	$ 18.05	$ 20.05	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.02	$ 0.07	$ 0.11	$ 0.15	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10	
Sub-Total	$ 2.33	$ 3.39	$ 5.50	$ 7.61	$ 9.72	$ 11.83	$ 12.88	$ 18.16	$ 23.43	$ 28.71	$ 33.98	$ 39.26	$ 44.53	$ 49.81	$ 55.08	
PTC Charge																
All kWh @ $ 0.08198 /kWh	$ -	$ 8.20	$ 24.59	$ 40.99	$ 57.39	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90	
Sub Total	$ 13.33	$ 23.43	$ 43.63	$ 63.83	$ 84.03	$ 104.23	$ 114.33	$ 164.83	$ 215.33	$ 265.82	$ 316.32	$ 366.82	$ 417.32	$ 467.82	$ 518.32	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 13.33**	**$ 23.43**	**$ 43.63**	**$ 63.83**	**$ 84.03**	**$ 104.23**	**$ 114.33**	**$ 164.83**	**$ 215.33**	**$ 265.82**	**$ 316.32**	**$ 366.82**	**$ 417.32**	**$ 467.82**	**$ 518.32**	

UNBUNDLED RATES - PROPOSED

NUG Charge																
All kWh @ 0.015 ¢/kWh	$ -	$ 0.02	$ 0.05	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75	
Distribution																
Distribution Charge @ $13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	
All kWh @ 4.103 ¢/kWh	$ -	$ 4.10	$ 12.31	$ 20.52	$ 28.72	$ 36.93	$ 41.03	$ 61.55	$ 82.06	$ 102.58	$ 123.09	$ 143.61	$ 164.12	$ 184.64	$ 205.15	
Sub-Total	$ 13.29	$ 17.39	$ 25.60	$ 33.81	$ 42.01	$ 50.22	$ 54.32	$ 74.84	$ 95.35	$ 115.87	$ 136.38	$ 156.90	$ 177.41	$ 197.93	$ 218.44	
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.53	$ 1.59	$ 2.65	$ 3.70	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.103 ¢/kWh	$ -	$ 0.10	$ 0.31	$ 0.52	$ 0.72	$ 0.93	$ 1.03	$ 1.55	$ 2.06	$ 2.58	$ 3.09	$ 3.61	$ 4.12	$ 4.64	$ 5.15	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @ 0.401 ¢/kWh	$ -	$ 0.40	$ 1.20	$ 2.01	$ 2.81	$ 3.61	$ 4.01	$ 6.02	$ 8.02	$ 10.03	$ 12.03	$ 14.04	$ 16.04	$ 18.05	$ 20.05	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.02	$ 0.07	$ 0.11	$ 0.15	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10	
Sub-Total	$ -	$ 1.06	$ 3.17	$ 5.28	$ 7.39	$ 9.50	$ 10.55	$ 15.83	$ 21.10	$ 26.38	$ 31.65	$ 36.93	$ 42.20	$ 47.48	$ 52.75	
PTC Charge																
All kWh @ $ 0.08198 /kWh	$ -	$ 8.20	$ 24.59	$ 40.99	$ 57.39	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90	
Sub Total	$ 13.29	$ 26.66	$ 53.40	$ 80.15	$ 106.89	$ 133.63	$ 147.00	$ 213.86	$ 280.71	$ 347.57	$ 414.42	$ 481.28	$ 548.13	$ 614.99	$ 681.84	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 13.29**	**$ 26.66**	**$ 53.40**	**$ 80.15**	**$ 106.89**	**$ 133.63**	**$ 147.00**	**$ 213.86**	**$ 280.71**	**$ 347.57**	**$ 414.42**	**$ 481.28**	**$ 548.13**	**$ 614.99**	**$ 681.84**	
% Increase	**-0.30%**	**13.79%**	**22.40%**	**25.56%**	**27.20%**	**28.21%**	**28.58%**	**29.75%**	**30.37%**	**30.75%**	**31.01%**	**31.20%**	**31.34%**	**31.46%**	**31.55%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS-V TIME OF DAY vs RATE GS-V

ENERGY USAGE																
Total Energy Usage	0	100	300	500	700	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000	
On Peak	0	33	99	165	231	297	330	495	660	825	990	1,155	1,320	1,485	1,650	
Off Peak	0	67	201	335	469	603	670	1,005	1,340	1,675	2,010	2,345	2,680	3,015	3,350	
Total Energy Usage	0	100	300	500	700	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000	

UNBUNDLED RATES - CURRENT

NUG Charge																
All kWh @ 0.015 ¢/kWh	$ -	$ 0.02	$ 0.05	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75	
Distribution																
Distribution Charge @ $11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	
On Peak @ 5.043 ¢/kWh	$ -	$ 1.66	$ 4.99	$ 8.32	$ 11.65	$ 14.98	$ 16.64	$ 24.96	$ 33.28	$ 41.60	$ 49.93	$ 58.25	$ 66.57	$ 74.89	$ 83.21	
Off Peak @ 0.283 ¢/kWh	$ -	$ 0.19	$ 0.57	$ 0.95	$ 1.33	$ 1.71	$ 1.90	$ 2.84	$ 3.79	$ 4.74	$ 5.69	$ 6.64	$ 7.58	$ 8.53	$ 9.48	
Sub-Total	$ 11.00	$ 12.85	$ 16.56	$ 20.27	$ 23.98	$ 27.68	$ 29.54	$ 38.81	$ 48.08	$ 57.35	$ 66.61	$ 75.88	$ 85.15	$ 94.42	$ 103.69	
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.53	$ 1.59	$ 2.65	$ 3.70	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.103 ¢/kWh	$ -	$ 0.10	$ 0.31	$ 0.52	$ 0.72	$ 0.93	$ 1.03	$ 1.55	$ 2.06	$ 2.58	$ 3.09	$ 3.61	$ 4.12	$ 4.64	$ 5.15	
Smart Meter Charge @ $2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	$ 2.33	
Default Service Support Charge @ 0.401 ¢/kWh	$ -	$ 0.40	$ 1.20	$ 2.01	$ 2.81	$ 3.61	$ 4.01	$ 6.02	$ 8.02	$ 10.03	$ 12.03	$ 14.04	$ 16.04	$ 18.05	$ 20.05	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.02	$ 0.07	$ 0.11	$ 0.15	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10	
Sub-Total	$ 2.33	$ 3.39	$ 5.50	$ 7.61	$ 9.72	$ 11.83	$ 12.88	$ 18.16	$ 23.43	$ 28.71	$ 33.98	$ 39.26	$ 44.53	$ 49.81	$ 55.08	
PTC Charge																
All kWh @ $ 0.08198 /kWh	$ -	$ 8.20	$ 24.59	$ 40.99	$ 57.39	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90	
Sub Total	$ 13.33	$ 24.45	$ 46.70	$ 68.94	$ 91.18	$ 113.43	$ 124.55	$ 180.16	$ 235.77	$ 291.38	$ 346.98	$ 402.59	$ 458.20	$ 513.81	$ 569.42	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 13.33**	**$ 24.45**	**$ 46.70**	**$ 68.94**	**$ 91.18**	**$ 113.43**	**$ 124.55**	**$ 180.16**	**$ 235.77**	**$ 291.38**	**$ 346.98**	**$ 402.59**	**$ 458.20**	**$ 513.81**	**$ 569.42**	

UNBUNDLED RATES - PROPOSED

NUG Charge																
All kWh @ 0.015 ¢/kWh	$ -	$ 0.02	$ 0.05	$ 0.08	$ 0.11	$ 0.14	$ 0.15	$ 0.23	$ 0.30	$ 0.38	$ 0.45	$ 0.53	$ 0.60	$ 0.68	$ 0.75	
Distribution																
Distribution Charge @ $13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	$ 13.29	
All kWh @ 4.103 ¢/kWh	$ -	$ 4.10	$ 12.31	$ 20.52	$ 28.72	$ 36.93	$ 41.03	$ 61.55	$ 82.06	$ 102.58	$ 123.09	$ 143.61	$ 164.12	$ 184.64	$ 205.15	
Sub-Total	$ 13.29	$ 17.39	$ 25.60	$ 33.81	$ 42.01	$ 50.22	$ 54.32	$ 74.84	$ 95.35	$ 115.87	$ 136.38	$ 156.90	$ 177.41	$ 197.93	$ 218.44	
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Universal Service Charge @ 0.529 ¢/kWh	$ -	$ 0.53	$ 1.59	$ 2.65	$ 3.70	$ 4.76	$ 5.29	$ 7.94	$ 10.58	$ 13.23	$ 15.87	$ 18.52	$ 21.16	$ 23.81	$ 26.45	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.103 ¢/kWh	$ -	$ 0.10	$ 0.31	$ 0.52	$ 0.72	$ 0.93	$ 1.03	$ 1.55	$ 2.06	$ 2.58	$ 3.09	$ 3.61	$ 4.12	$ 4.64	$ 5.15	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @ 0.401 ¢/kWh	$ -	$ 0.40	$ 1.20	$ 2.01	$ 2.81	$ 3.61	$ 4.01	$ 6.02	$ 8.02	$ 10.03	$ 12.03	$ 14.04	$ 16.04	$ 18.05	$ 20.05	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.02	$ 0.07	$ 0.11	$ 0.15	$ 0.20	$ 0.22	$ 0.33	$ 0.44	$ 0.55	$ 0.66	$ 0.77	$ 0.88	$ 0.99	$ 1.10	
Sub-Total	$ -	$ 1.06	$ 3.17	$ 5.28	$ 7.39	$ 9.50	$ 10.55	$ 15.83	$ 21.10	$ 26.38	$ 31.65	$ 36.93	$ 42.20	$ 47.48	$ 52.75	
PTC Charge																
All kWh @ $ 0.08198 /kWh	$ -	$ 8.20	$ 24.59	$ 40.99	$ 57.39	$ 73.78	$ 81.98	$ 122.97	$ 163.96	$ 204.95	$ 245.94	$ 286.93	$ 327.92	$ 368.91	$ 409.90	
Sub Total	$ 13.29	$ 26.66	$ 53.40	$ 80.15	$ 106.89	$ 133.63	$ 147.00	$ 213.86	$ 280.71	$ 347.57	$ 414.42	$ 481.28	$ 548.13	$ 614.99	$ 681.84	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 13.29**	**$ 26.66**	**$ 53.40**	**$ 80.15**	**$ 106.89**	**$ 133.63**	**$ 147.00**	**$ 213.86**	**$ 280.71**	**$ 347.57**	**$ 414.42**	**$ 481.28**	**$ 548.13**	**$ 614.99**	**$ 681.84**	
% Increase	**-0.30%**	**9.03%**	**14.36%**	**16.25%**	**17.22%**	**17.81%**	**18.03%**	**18.70%**	**19.06%**	**19.28%**	**19.43%**	**19.54%**	**19.63%**	**19.69%**	**19.74%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS - SMALL - SINGLE PHASE
At Average Levels of kWh Use

KW Demand																
Total kW	0	1	1	1	1	1	1	1	3	3	3	3	3	5	5	
Hrs Use	0	100	200	300	400	500	600	730	100	200	300	400	500	100	200	
ENERGY USAGE																
Monthly Energy Usage	0	100	200	300	400	500	600	730	300	600	900	1,200	1,500	500	1,000	
Total Energy Usage	0	100	200	300	400	500	600	730	300	600	900	1,200	1,500	500	1,000	
UNBUNDLED RATES - CURRENT																
NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (0.00)	$ (0.00)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.02)	$ (0.02)	$ (0.03)	$ (0.01)	$ (0.02)	
Distribution																
Distribution Charge @ $10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	
All kWh @ 1.264 ¢/kWh	$ -	$ 1.26	$ 2.53	$ 3.79	$ 5.06	$ 6.32	$ 7.58	$ 9.23	$ 3.79	$ 7.58	$ 11.38	$ 15.17	$ 18.96	$ 6.32	$ 12.64	
Sub-Total	$ 10.88	$ 12.14	$ 13.41	$ 14.67	$ 15.94	$ 17.20	$ 18.46	$ 20.11	$ 14.67	$ 18.46	$ 22.26	$ 26.05	$ 29.84	$ 17.20	$ 23.52	
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 0.19	$ 0.37	$ 0.56	$ 0.74	$ 0.93	$ 1.11	$ 1.35	$ 0.56	$ 1.11	$ 1.67	$ 2.22	$ 2.78	$ 0.93	$ 1.85	
Smart Meter Charge @ $2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	
Default Service Support Charge @ 0.260 ¢/kWh	$ -	$ 0.26	$ 0.52	$ 0.78	$ 1.04	$ 1.30	$ 1.56	$ 1.90	$ 0.78	$ 1.56	$ 2.34	$ 3.12	$ 3.90	$ 1.30	$ 2.60	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.02	$ 0.04	$ 0.07	$ 0.09	$ 0.11	$ 0.13	$ 0.16	$ 0.07	$ 0.13	$ 0.20	$ 0.26	$ 0.33	$ 0.11	$ 0.22	
Sub-Total	$ 2.38	$ 2.85	$ 3.31	$ 3.78	$ 4.25	$ 4.72	$ 5.18	$ 5.79	$ 3.78	$ 5.18	$ 6.58	$ 7.98	$ 9.39	$ 4.72	$ 7.05	
PTC Charge																
All kWh @ $ 0.08048 /kWh	$ -	$ 8.05	$ 16.10	$ 24.14	$ 32.19	$ 40.24	$ 48.29	$ 58.75	$ 24.14	$ 48.29	$ 72.43	$ 96.58	$ 120.72	$ 40.24	$ 80.48	
Sub Total	$ 13.26	$ 23.04	$ 32.81	$ 42.59	$ 52.37	$ 62.15	$ 71.92	$ 84.63	$ 42.59	$ 71.92	$ 101.25	$ 130.58	$ 159.92	$ 62.15	$ 111.03	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 13.26**	**$ 23.04**	**$ 32.81**	**$ 42.59**	**$ 52.37**	**$ 62.15**	**$ 71.92**	**$ 84.63**	**$ 42.59**	**$ 71.92**	**$ 101.25**	**$ 130.58**	**$ 159.92**	**$ 62.15**	**$ 111.03**	
UNBUNDLED RATES - PROPOSED																
NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (0.00)	$ (0.00)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.02)	$ (0.02)	$ (0.03)	$ (0.01)	$ (0.02)	
Distribution																
Distribution Charge @ $16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.53	$ 16.53	
All kWh @ 3.082 ¢/kWh	$ -	$ 3.08	$ 6.16	$ 9.25	$ 12.33	$ 15.41	$ 18.49	$ 22.50	$ 9.25	$ 18.49	$ 27.74	$ 36.98	$ 46.23	$ 15.41	$ 30.82	
Sub-Total	$ 16.53	$ 19.61	$ 22.69	$ 25.78	$ 28.86	$ 31.94	$ 35.02	$ 39.03	$ 25.78	$ 35.02	$ 44.27	$ 53.51	$ 62.76	$ 31.94	$ 47.35	
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 0.19	$ 0.37	$ 0.56	$ 0.74	$ 0.93	$ 1.11	$ 1.35	$ 0.56	$ 1.11	$ 1.67	$ 2.22	$ 2.78	$ 0.93	$ 1.85	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @ 0.260 ¢/kWh	$ -	$ 0.26	$ 0.52	$ 0.78	$ 1.04	$ 1.30	$ 1.56	$ 1.90	$ 0.78	$ 1.56	$ 2.34	$ 3.12	$ 3.90	$ 1.30	$ 2.60	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.02	$ 0.04	$ 0.07	$ 0.09	$ 0.11	$ 0.13	$ 0.16	$ 0.07	$ 0.13	$ 0.20	$ 0.26	$ 0.33	$ 0.11	$ 0.22	
Sub-Total	$ -	$ 0.47	$ 0.93	$ 1.40	$ 1.87	$ 2.34	$ 2.80	$ 3.41	$ 1.40	$ 2.80	$ 4.20	$ 5.60	$ 7.01	$ 2.34	$ 4.67	
PTC Charge																
All kWh @ $ 0.08048 /kWh	$ -	$ 8.05	$ 16.10	$ 24.14	$ 32.19	$ 40.24	$ 48.29	$ 58.75	$ 24.14	$ 48.29	$ 72.43	$ 96.58	$ 120.72	$ 40.24	$ 80.48	
Sub Total	$ 16.53	$ 28.13	$ 39.72	$ 51.32	$ 62.91	$ 74.51	$ 86.10	$ 101.17	$ 51.32	$ 86.10	$ 120.89	$ 155.67	$ 190.46	$ 74.51	$ 132.48	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 16.53**	**$ 28.13**	**$ 39.72**	**$ 51.32**	**$ 62.91**	**$ 74.51**	**$ 86.10**	**$ 101.17**	**$ 51.32**	**$ 86.10**	**$ 120.89**	**$ 155.67**	**$ 190.46**	**$ 74.51**	**$ 132.48**	
% Increase	**24.66%**	**22.09%**	**21.05%**	**20.48%**	**20.13%**	**19.89%**	**19.71%**	**19.55%**	**20.48%**	**19.71%**	**19.39%**	**19.21%**	**19.10%**	**19.89%**	**19.32%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS MEDIUM - SINGLE PHASE - NON TIME OF DAY
With Demands 10 - 20 KW
At Average Levels of kWh Use

KW Demand																
Total kW	0	10	10	10	10	10	10	10	20	20	20	20	20	20	20	
Hrs Use	0	100	200	300	400	500	600	730	100	200	300	400	500	600	730	
REACTIVE DEMAND																
rkVA	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
ENERGY USAGE																
Monthly Energy Usage	0	1,000	2,000	3,000	4,000	5,000	6,000	7,300	2,000	4,000	6,000	8,000	10,000	12,000	14,600	
Total Energy Usage	0	1,000	2,000	3,000	4,000	5,000	6,000	7,300	2,000	4,000	6,000	8,000	10,000	12,000	14,600	

UNBUNDLED RATES - CURRENT

NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (0.02)	$ (0.04)	$ (0.06)	$ (0.08)	$ (0.10)	$ (0.12)	$ (0.15)	$ (0.04)	$ (0.08)	$ (0.12)	$ (0.16)	$ (0.20)	$ (0.24)	$ (0.29)	
Distribution																
Distribution Charge @ $10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	
All kW @ $3.82/kW	$ -	$ 38.20	$ 38.20	$ 38.20	$ 38.20	$ 38.20	$ 38.20	$ 38.20	$ 76.40	$ 76.40	$ 76.40	$ 76.40	$ 76.40	$ 76.40	$ 76.40	
All kWh @ 0.050 ¢/kWh	$ -	$ 0.50	$ 1.00	$ 1.50	$ 2.00	$ 2.50	$ 3.00	$ 3.65	$ 1.00	$ 2.00	$ 3.00	$ 4.00	$ 5.00	$ 6.00	$ 7.30	
Sub-Total	$ 10.88	$ 49.58	$ 50.08	$ 50.58	$ 51.08	$ 51.58	$ 52.08	$ 52.73	$ 88.28	$ 89.28	$ 90.28	$ 91.28	$ 92.28	$ 93.28	$ 94.58	
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 1.85	$ 3.70	$ 5.55	$ 7.40	$ 9.25	$ 11.10	$ 13.51	$ 3.70	$ 7.40	$ 11.10	$ 14.80	$ 18.50	$ 22.20	$ 27.01	
Smart Meter Charge @ $2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 2.48	$ 4.96	$ 7.44	$ 9.92	$ 12.40	$ 14.88	$ 18.10	$ 4.96	$ 9.92	$ 14.88	$ 19.84	$ 24.80	$ 29.76	$ 36.21	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.22	$ 0.44	$ 0.66	$ 0.88	$ 1.10	$ 1.32	$ 1.61	$ 0.44	$ 0.88	$ 1.32	$ 1.76	$ 2.20	$ 2.64	$ 3.21	
Sub-Total	$ 2.38	$ 6.93	$ 11.48	$ 16.03	$ 20.58	$ 25.13	$ 29.68	$ 35.60	$ 11.48	$ 20.58	$ 29.68	$ 38.78	$ 47.88	$ 56.98	$ 68.81	
PTC Charge																
All kWh @ $ 0.08048 /kWh	$ -	$ 80.48	$ 160.96	$ 241.44	$ 321.92	$ 402.40	$ 482.88	$ 587.50	$ 160.96	$ 321.92	$ 482.88	$ 643.84	$ 804.80	$ 965.76	$ 1,175.01	
Sub Total	$ 13.26	$ 136.97	$ 222.48	$ 307.99	$ 393.50	$ 479.01	$ 564.52	$ 675.68	$ 260.68	$ 431.70	$ 602.72	$ 773.74	$ 944.76	$ 1,115.78	$ 1,338.11	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 13.26**	**$ 136.97**	**$ 222.48**	**$ 307.99**	**$ 393.50**	**$ 479.01**	**$ 564.52**	**$ 675.68**	**$ 260.68**	**$ 431.70**	**$ 602.72**	**$ 773.74**	**$ 944.76**	**$ 1,115.78**	**$ 1,338.11**	

UNBUNDLED RATES - PROPOSED

NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (0.02)	$ (0.04)	$ (0.06)	$ (0.08)	$ (0.10)	$ (0.12)	$ (0.15)	$ (0.04)	$ (0.08)	$ (0.12)	$ (0.16)	$ (0.20)	$ (0.24)	$ (0.29)	
Distribution																
Distribution Charge @ $19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	
All kW @ $5.22/kW	$ -	$ 52.20	$ 52.20	$ 52.20	$ 52.20	$ 52.20	$ 52.20	$ 52.20	$ 104.40	$ 104.40	$ 104.40	$ 104.40	$ 104.40	$ 104.40	$ 104.40	
All rkVA @ $0.20 /rkVA	$ -	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.23	
Sub-Total	$ 19.01	$ 71.32	$ 71.32	$ 71.32	$ 71.32	$ 71.32	$ 71.32	$ 71.32	$ 123.64	$ 123.64	$ 123.64	$ 123.64	$ 123.64	$ 123.64	$ 123.64	
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 1.85	$ 3.70	$ 5.55	$ 7.40	$ 9.25	$ 11.10	$ 13.51	$ 3.70	$ 7.40	$ 11.10	$ 14.80	$ 18.50	$ 22.20	$ 27.01	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 2.48	$ 4.96	$ 7.44	$ 9.92	$ 12.40	$ 14.88	$ 18.10	$ 4.96	$ 9.92	$ 14.88	$ 19.84	$ 24.80	$ 29.76	$ 36.21	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.22	$ 0.44	$ 0.66	$ 0.88	$ 1.10	$ 1.32	$ 1.61	$ 0.44	$ 0.88	$ 1.32	$ 1.76	$ 2.20	$ 2.64	$ 3.21	
Sub-Total	$ -	$ 4.55	$ 9.10	$ 13.65	$ 18.20	$ 22.75	$ 27.30	$ 33.22	$ 9.10	$ 18.20	$ 27.30	$ 36.40	$ 45.50	$ 54.60	$ 66.43	
PTC Charge																
All kWh @ $ 0.08048 /kWh	$ -	$ 80.48	$ 160.96	$ 241.44	$ 321.92	$ 402.40	$ 482.88	$ 587.50	$ 160.96	$ 321.92	$ 482.88	$ 643.84	$ 804.80	$ 965.76	$ 1,175.01	
Sub Total	$ 19.01	$ 156.33	$ 241.34	$ 326.35	$ 411.36	$ 496.37	$ 581.38	$ 691.90	$ 293.66	$ 463.68	$ 633.70	$ 803.72	$ 973.74	$ 1,143.76	$ 1,364.78	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 19.01**	**$ 156.33**	**$ 241.34**	**$ 326.35**	**$ 411.36**	**$ 496.37**	**$ 581.38**	**$ 691.90**	**$ 293.66**	**$ 463.68**	**$ 633.70**	**$ 803.72**	**$ 973.74**	**$ 1,143.76**	**$ 1,364.78**	
% Increase	**43.36%**	**14.14%**	**8.48%**	**5.96%**	**4.54%**	**3.62%**	**2.99%**	**2.40%**	**12.65%**	**7.41%**	**5.14%**	**3.87%**	**3.07%**	**2.51%**	**1.99%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS MEDIUM - SINGLE PHASE - 12 HOUR ON PEAK TIME OF DAY vs GS-MEDIUM
With Demands 10 - 20 KW
At Average Levels of kWh Use

KW Demand																
Total kW	0	10	10	10	10	10	10	10	20	20	20	20	20	20	20	
Hrs Use	0	100	200	300	400	500	600	730	100	200	300	400	500	600	730	
REACTIVE DEMAND																
rkVA	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
ENERGY USAGE																
Monthly Energy Usage	0	1,000	2,000	3,000	4,000	5,000	6,000	7,300	2,000	4,000	6,000	8,000	10,000	12,000	14,600	
Total Energy Usage	0	1,000	2,000	3,000	4,000	5,000	6,000	7,300	2,000	4,000	6,000	8,000	10,000	12,000	14,600	

UNBUNDLED RATES - CURRENT

NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (0.02)	$ (0.04)	$ (0.06)	$ (0.08)	$ (0.10)	$ (0.12)	$ (0.15)	$ (0.04)	$ (0.08)	$ (0.12)	$ (0.16)	$ (0.20)	$ (0.24)	$ (0.29)	
Distribution																
Distribution Charge @ $10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	
All kW @ $3.82/kW	$ -	$ 38.20	$ 38.20	$ 38.20	$ 38.20	$ 38.20	$ 38.20	$ 38.20	$ 76.40	$ 76.40	$ 76.40	$ 76.40	$ 76.40	$ 76.40	$ 76.40	
All kWh @ 0.050 ¢/kWh	$ -	$ 0.50	$ 1.00	$ 1.50	$ 2.00	$ 2.50	$ 3.00	$ 3.65	$ 1.00	$ 2.00	$ 3.00	$ 4.00	$ 5.00	$ 6.00	$ 7.30	
Sub-Total	$ 10.88	$ 49.58	$ 50.08	$ 50.58	$ 51.08	$ 51.58	$ 52.08	$ 52.73	$ 88.28	$ 89.28	$ 90.28	$ 91.28	$ 92.28	$ 93.28	$ 94.58	
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 1.85	$ 3.70	$ 5.55	$ 7.40	$ 9.25	$ 11.10	$ 13.51	$ 3.70	$ 7.40	$ 11.10	$ 14.80	$ 18.50	$ 22.20	$ 27.01	
Smart Meter Charge @ $2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 2.48	$ 4.96	$ 7.44	$ 9.92	$ 12.40	$ 14.88	$ 18.10	$ 4.96	$ 9.92	$ 14.88	$ 19.84	$ 24.80	$ 29.76	$ 36.21	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.22	$ 0.44	$ 0.66	$ 0.88	$ 1.10	$ 1.32	$ 1.61	$ 0.44	$ 0.88	$ 1.32	$ 1.76	$ 2.20	$ 2.64	$ 3.21	
Sub-Total	$ 2.38	$ 6.93	$ 11.48	$ 16.03	$ 20.58	$ 25.13	$ 29.68	$ 35.60	$ 11.48	$ 20.58	$ 29.68	$ 38.78	$ 47.88	$ 56.98	$ 68.81	
PTC Charge																
All kWh @ $ 0.08048 /kWh	$ -	$ 80.48	$ 160.96	$ 241.44	$ 321.92	$ 402.40	$ 482.88	$ 587.50	$ 160.96	$ 321.92	$ 482.88	$ 643.84	$ 804.80	$ 965.76	$ 1,175.01	
Sub Total	$ 13.26	$ 136.97	$ 222.48	$ 307.99	$ 393.50	$ 479.01	$ 564.52	$ 675.68	$ 260.68	$ 431.70	$ 602.72	$ 773.74	$ 944.76	$ 1,115.78	$ 1,338.11	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 13.26**	**$ 136.97**	**$ 222.48**	**$ 307.99**	**$ 393.50**	**$ 479.01**	**$ 564.52**	**$ 675.68**	**$ 260.68**	**$ 431.70**	**$ 602.72**	**$ 773.74**	**$ 944.76**	**$ 1,115.78**	**$ 1,338.11**	

UNBUNDLED RATES - PROPOSED

NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (0.02)	$ (0.04)	$ (0.06)	$ (0.08)	$ (0.10)	$ (0.12)	$ (0.15)	$ (0.04)	$ (0.08)	$ (0.12)	$ (0.16)	$ (0.20)	$ (0.24)	$ (0.29)	
Distribution																
Distribution Charge @ $19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	
All kW @ $5.22/kW	$ -	$ 52.20	$ 52.20	$ 52.20	$ 52.20	$ 52.20	$ 52.20	$ 52.20	$ 104.40	$ 104.40	$ 104.40	$ 104.40	$ 104.40	$ 104.40	$ 104.40	
All rkVA @$ 0.20 /rkVA	$ -	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.23	
Sub-Total	$ 19.01	$ 71.32	$ 71.32	$ 71.32	$ 71.32	$ 71.32	$ 71.32	$ 71.32	$ 123.64	$ 123.64	$ 123.64	$ 123.64	$ 123.64	$ 123.64	$ 123.64	
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 1.85	$ 3.70	$ 5.55	$ 7.40	$ 9.25	$ 11.10	$ 13.51	$ 3.70	$ 7.40	$ 11.10	$ 14.80	$ 18.50	$ 22.20	$ 27.01	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 2.48	$ 4.96	$ 7.44	$ 9.92	$ 12.40	$ 14.88	$ 18.10	$ 4.96	$ 9.92	$ 14.88	$ 19.84	$ 24.80	$ 29.76	$ 36.21	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.22	$ 0.44	$ 0.66	$ 0.88	$ 1.10	$ 1.32	$ 1.61	$ 0.44	$ 0.88	$ 1.32	$ 1.76	$ 2.20	$ 2.64	$ 3.21	
Sub-Total	$ -	$ 4.55	$ 9.10	$ 13.65	$ 18.20	$ 22.75	$ 27.30	$ 33.22	$ 9.10	$ 18.20	$ 27.30	$ 36.40	$ 45.50	$ 54.60	$ 66.43	
PTC Charge																
All kWh @ $ 0.08048 /kWh	$ -	$ 80.48	$ 160.96	$ 241.44	$ 321.92	$ 402.40	$ 482.88	$ 587.50	$ 160.96	$ 321.92	$ 482.88	$ 643.84	$ 804.80	$ 965.76	$ 1,175.01	
Sub Total	$ 19.01	$ 156.33	$ 241.34	$ 326.35	$ 411.36	$ 496.37	$ 581.38	$ 691.90	$ 293.66	$ 463.68	$ 633.70	$ 803.72	$ 973.74	$ 1,143.76	$ 1,364.78	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 19.01**	**$ 156.33**	**$ 241.34**	**$ 326.35**	**$ 411.36**	**$ 496.37**	**$ 581.38**	**$ 691.90**	**$ 293.66**	**$ 463.68**	**$ 633.70**	**$ 803.72**	**$ 973.74**	**$ 1,143.76**	**$ 1,364.78**	
% Increase	**43.36%**	**14.14%**	**8.48%**	**5.96%**	**4.54%**	**3.62%**	**2.99%**	**2.40%**	**12.65%**	**7.41%**	**5.14%**	**3.87%**	**3.07%**	**2.51%**	**1.99%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS MEDIUM - SINGLE PHASE - 8 HOUR ON PEAK TIME OF DAY vs GS-MEDIUM
With Demands 10 - 20 KW
At Average Levels of kWh Use

KW Demand															
Total kW	0	10	10	10	10	10	10	10	20	20	20	20	20	20	20
Hrs Use	0	100	200	300	400	500	600	730	100	200	300	400	500	600	730
REACTIVE DEMAND															
rkVA	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ENERGY USAGE															
Monthly Energy Usage	0	1,000	2,000	3,000	4,000	5,000	6,000	7,300	2,000	4,000	6,000	8,000	10,000	12,000	14,600
Total Energy Usage	0	1,000	2,000	3,000	4,000	5,000	6,000	7,300	2,000	4,000	6,000	8,000	10,000	12,000	14,600

UNBUNDLED RATES - CURRENT

NUG Charge															
All kWh @ -0.002 ¢/kWh	$ -	$ (0.02)	$ (0.04)	$ (0.06)	$ (0.08)	$ (0.10)	$ (0.12)	$ (0.15)	$ (0.04)	$ (0.08)	$ (0.12)	$ (0.16)	$ (0.20)	$ (0.24)	$ (0.29)
Distribution															
Distribution Charge @ $10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88	$ 10.88
All kW @ $3.82/kW	$ -	$ 38.20	$ 38.20	$ 38.20	$ 38.20	$ 38.20	$ 38.20	$ 38.20	$ 76.40	$ 76.40	$ 76.40	$ 76.40	$ 76.40	$ 76.40	$ 76.40
All kWh @ 0.050 ¢/kWh	$ -	$ 0.50	$ 1.00	$ 1.50	$ 2.00	$ 2.50	$ 3.00	$ 3.65	$ 1.00	$ 2.00	$ 3.00	$ 4.00	$ 5.00	$ 6.00	$ 7.30
Sub-Total	$ 10.88	$ 49.58	$ 50.08	$ 50.58	$ 51.08	$ 51.58	$ 52.08	$ 52.73	$ 88.28	$ 89.28	$ 90.28	$ 91.28	$ 92.28	$ 93.28	$ 94.58
Riders															
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 1.85	$ 3.70	$ 5.55	$ 7.40	$ 9.25	$ 11.10	$ 13.51	$ 3.70	$ 7.40	$ 11.10	$ 14.80	$ 18.50	$ 22.20	$ 27.01
Smart Meter Charge @ $2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 2.48	$ 4.96	$ 7.44	$ 9.92	$ 12.40	$ 14.88	$ 18.10	$ 4.96	$ 9.92	$ 14.88	$ 19.84	$ 24.80	$ 29.76	$ 36.21
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.22	$ 0.44	$ 0.66	$ 0.88	$ 1.10	$ 1.32	$ 1.61	$ 0.44	$ 0.88	$ 1.32	$ 1.76	$ 2.20	$ 2.64	$ 3.21
Sub-Total	$ 2.38	$ 6.93	$ 11.48	$ 16.03	$ 20.58	$ 25.13	$ 29.68	$ 35.60	$ 11.48	$ 20.58	$ 29.68	$ 38.78	$ 47.88	$ 56.98	$ 68.81
PTC Charge															
All kWh @ $ 0.08048 /kWh	$ -	$ 80.48	$ 160.96	$ 241.44	$ 321.92	$ 402.40	$ 482.88	$ 587.50	$ 160.96	$ 321.92	$ 482.88	$ 643.84	$ 804.80	$ 965.76	$ 1,175.01
Sub Total	$ 13.26	$ 136.97	$ 222.48	$ 307.99	$ 393.50	$ 479.01	$ 564.52	$ 675.68	$ 260.68	$ 431.70	$ 602.72	$ 773.74	$ 944.76	$ 1,115.78	$ 1,338.11
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 13.26**	**$ 136.97**	**$ 222.48**	**$ 307.99**	**$ 393.50**	**$ 479.01**	**$ 564.52**	**$ 675.68**	**$ 260.68**	**$ 431.70**	**$ 602.72**	**$ 773.74**	**$ 944.76**	**$ 1,115.78**	**$ 1,338.11**

UNBUNDLED RATES - PROPOSED

NUG Charge															
All kWh @ -0.002 ¢/kWh	$ -	$ (0.02)	$ (0.04)	$ (0.06)	$ (0.08)	$ (0.10)	$ (0.12)	$ (0.15)	$ (0.04)	$ (0.08)	$ (0.12)	$ (0.16)	$ (0.20)	$ (0.24)	$ (0.29)
Distribution															
Distribution Charge @ $19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01	$ 19.01
All kW @ $5.22/kW	$ -	$ 52.20	$ 52.20	$ 52.20	$ 52.20	$ 52.20	$ 52.20	$ 52.20	$ 104.40	$ 104.40	$ 104.40	$ 104.40	$ 104.40	$ 104.40	$ 104.40
All rkVA @$ 0.20 /rkVA	$ -	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.23	$ 0.23
Sub-Total	$ 19.01	$ 71.32	$ 71.32	$ 71.32	$ 71.32	$ 71.32	$ 71.32	$ 71.32	$ 123.64	$ 123.64	$ 123.64	$ 123.64	$ 123.64	$ 123.64	$ 123.64
Riders															
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 1.85	$ 3.70	$ 5.55	$ 7.40	$ 9.25	$ 11.10	$ 13.51	$ 3.70	$ 7.40	$ 11.10	$ 14.80	$ 18.50	$ 22.20	$ 27.01
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 2.48	$ 4.96	$ 7.44	$ 9.92	$ 12.40	$ 14.88	$ 18.10	$ 4.96	$ 9.92	$ 14.88	$ 19.84	$ 24.80	$ 29.76	$ 36.21
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.22	$ 0.44	$ 0.66	$ 0.88	$ 1.10	$ 1.32	$ 1.61	$ 0.44	$ 0.88	$ 1.32	$ 1.76	$ 2.20	$ 2.64	$ 3.21
Sub-Total	$ -	$ 4.55	$ 9.10	$ 13.65	$ 18.20	$ 22.75	$ 27.30	$ 33.22	$ 9.10	$ 18.20	$ 27.30	$ 36.40	$ 45.50	$ 54.60	$ 66.43
PTC Charge															
All kWh @ $ 0.08048 /kWh	$ -	$ 80.48	$ 160.96	$ 241.44	$ 321.92	$ 402.40	$ 482.88	$ 587.50	$ 160.96	$ 321.92	$ 482.88	$ 643.84	$ 804.80	$ 965.76	$ 1,175.01
Sub Total	$ 19.01	$ 156.33	$ 241.34	$ 326.35	$ 411.36	$ 496.37	$ 581.38	$ 691.90	$ 293.66	$ 463.68	$ 633.70	$ 803.72	$ 973.74	$ 1,143.76	$ 1,364.78
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 19.01**	**$ 156.33**	**$ 241.34**	**$ 326.35**	**$ 411.36**	**$ 496.37**	**$ 581.38**	**$ 691.90**	**$ 293.66**	**$ 463.68**	**$ 633.70**	**$ 803.72**	**$ 973.74**	**$ 1,143.76**	**$ 1,364.78**
% Increase	**43.36%**	**14.14%**	**8.48%**	**5.96%**	**4.54%**	**3.62%**	**2.99%**	**2.40%**	**12.65%**	**7.41%**	**5.14%**	**3.87%**	**3.07%**	**2.51%**	**1.99%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS-MEDIUM - THREE PHASE - NON TIME OF DAY
With Demands 25-100 KW
At Average Levels of kWh Use

KW Demand																		
Total kW	25	25	25	25	25	50	50	50	50	75	75	75	75	100	100	100	100	
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730	
REACTIVE DEMAND																		
rkVA	1	1	1	1	1	3	3	3	3	4	4	4	4	6	6	6	6	
ENERGY USAGE																		
Monthly Energy Usage	0	2,500	7,500	12,500	18,250	5,000	15,000	25,000	36,500	7,500	22,500	37,500	54,750	10,000	30,000	50,000	73,000	
Total Energy Usage	0	2,500	7,500	12,500	18,250	5,000	15,000	25,000	36,500	7,500	22,500	37,500	54,750	10,000	30,000	50,000	73,000	

UNBUNDLED RATES - CURRENT

NUG Charge																		
All kWh @ -0.002 ¢/kWh	$ -	$ (0.05)	$ (0.15)	$ (0.25)	$ (0.37)	$ (0.10)	$ (0.30)	$ (0.50)	$ (0.73)	$ (0.15)	$ (0.45)	$ (0.75)	$ (1.10)	$ (0.20)	$ (0.60)	$ (1.00)	$ (1.46)	
Distribution																		
Distribution Charge @ $21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	
All kW @ $3.82/kW	$ 95.50	$ 95.50	$ 95.50	$ 95.50	$ 95.50	$ 191.00	$ 191.00	$ 191.00	$ 191.00	$ 286.50	$ 286.50	$ 286.50	$ 286.50	$ 382.00	$ 382.00	$ 382.00	$ 382.00	
All kWh @ 0.050 ¢/kWh	$ -	$ 1.25	$ 3.75	$ 6.25	$ 9.13	$ 2.50	$ 7.50	$ 12.50	$ 18.25	$ 3.75	$ 11.25	$ 18.75	$ 27.38	$ 5.00	$ 15.00	$ 25.00	$ 36.50	
Sub-Total	$ 117.02	$ 118.27	$ 120.77	$ 123.27	$ 126.15	$ 215.02	$ 220.02	$ 225.02	$ 230.77	$ 311.77	$ 319.27	$ 326.77	$ 335.40	$ 408.52	$ 418.52	$ 428.52	$ 440.02	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 4.63	$ 13.88	$ 23.13	$ 33.76	$ 9.25	$ 27.75	$ 46.25	$ 67.53	$ 13.88	$ 41.63	$ 69.38	$ 101.29	$ 18.50	$ 55.50	$ 92.50	$ 135.05	
Smart Meter Charge @ $2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 6.20	$ 18.60	$ 31.00	$ 45.26	$ 12.40	$ 37.20	$ 62.00	$ 90.52	$ 18.60	$ 55.80	$ 93.00	$ 135.78	$ 24.80	$ 74.40	$ 124.00	$ 181.04	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.55	$ 1.65	$ 2.75	$ 4.02	$ 1.10	$ 3.30	$ 5.50	$ 8.03	$ 1.65	$ 4.95	$ 8.25	$ 12.05	$ 2.20	$ 6.60	$ 11.00	$ 16.06	
Sub-Total	$ 2.38	$ 13.76	$ 36.51	$ 59.26	$ 85.42	$ 25.13	$ 70.63	$ 116.13	$ 168.46	$ 36.51	$ 104.76	$ 173.01	$ 251.49	$ 47.88	$ 138.88	$ 229.88	$ 334.53	
PTC Charge																		
All kWh @ $ 0.08048 /kWh	$ -	$ 201.20	$ 603.60	$ 1,006.00	$ 1,468.76	$ 402.40	$ 1,207.20	$ 2,012.00	$ 2,937.52	$ 603.60	$ 1,810.80	$ 3,018.00	$ 4,406.28	$ 804.80	$ 2,414.40	$ 4,024.00	$ 5,875.04	
Sub Total	$ 119.40	$ 333.18	$ 760.73	$ 1,188.28	$ 1,679.96	$ 642.45	$ 1,497.55	$ 2,352.65	$ 3,336.02	$ 951.73	$ 2,234.38	$ 3,517.03	$ 4,992.07	$ 1,261.00	$ 2,971.20	$ 4,681.40	$ 6,648.13	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 119.40**	**$ 333.18**	**$ 760.73**	**$ 1,188.28**	**$ 1,679.96**	**$ 642.45**	**$ 1,497.55**	**$ 2,352.65**	**$ 3,336.02**	**$ 951.73**	**$ 2,234.38**	**$ 3,517.03**	**$ 4,992.07**	**$ 1,261.00**	**$ 2,971.20**	**$ 4,681.40**	**$ 6,648.13**	

UNBUNDLED RATES - PROPOSED

NUG Charge																		
All kWh @ -0.002 ¢/kWh	$ -	$ (0.05)	$ (0.15)	$ (0.25)	$ (0.37)	$ (0.10)	$ (0.30)	$ (0.50)	$ (0.73)	$ (0.15)	$ (0.45)	$ (0.75)	$ (1.10)	$ (0.20)	$ (0.60)	$ (1.00)	$ (1.46)	
Distribution																		
Distribution Charge @ $34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	
All kW @ $5.22/kW	$ 130.50	$ 130.50	$ 130.50	$ 130.50	$ 130.50	$ 261.00	$ 261.00	$ 261.00	$ 261.00	$ 391.50	$ 391.50	$ 391.50	$ 391.50	$ 522.00	$ 522.00	$ 522.00	$ 522.00	
All rkVA @ $0.20 /rkVA	$ 0.28	$ 0.28	$ 0.28	$ 0.28	$ 0.28	$ 0.57	$ 0.57	$ 0.57	$ 0.57	$ 0.85	$ 0.85	$ 0.85	$ 0.85	$ 1.13	$ 1.13	$ 1.13	$ 1.13	
Sub-Total	$ 165.17	$ 165.17	$ 165.17	$ 165.17	$ 165.17	$ 295.96	$ 295.96	$ 295.96	$ 295.96	$ 426.74	$ 426.74	$ 426.74	$ 426.74	$ 557.52	$ 557.52	$ 557.52	$ 557.52	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 4.63	$ 13.88	$ 23.13	$ 33.76	$ 9.25	$ 27.75	$ 46.25	$ 67.53	$ 13.88	$ 41.63	$ 69.38	$ 101.29	$ 18.50	$ 55.50	$ 92.50	$ 135.05	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 6.20	$ 18.60	$ 31.00	$ 45.26	$ 12.40	$ 37.20	$ 62.00	$ 90.52	$ 18.60	$ 55.80	$ 93.00	$ 135.78	$ 24.80	$ 74.40	$ 124.00	$ 181.04	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.55	$ 1.65	$ 2.75	$ 4.02	$ 1.10	$ 3.30	$ 5.50	$ 8.03	$ 1.65	$ 4.95	$ 8.25	$ 12.05	$ 2.20	$ 6.60	$ 11.00	$ 16.06	
Sub-Total	$ -	$ 11.38	$ 34.13	$ 56.88	$ 83.04	$ 22.75	$ 68.25	$ 113.75	$ 166.08	$ 34.13	$ 102.38	$ 170.63	$ 249.11	$ 45.50	$ 136.50	$ 227.50	$ 332.15	
PTC Charge																		
All kWh @ $ 0.08048 /kWh	$ -	$ 201.20	$ 603.60	$ 1,006.00	$ 1,468.76	$ 402.40	$ 1,207.20	$ 2,012.00	$ 2,937.52	$ 603.60	$ 1,810.80	$ 3,018.00	$ 4,406.28	$ 804.80	$ 2,414.40	$ 4,024.00	$ 5,875.04	
Sub Total	$ 165.17	$ 377.70	$ 802.75	$ 1,227.80	$ 1,716.61	$ 721.01	$ 1,571.11	$ 2,421.21	$ 3,398.82	$ 1,064.32	$ 2,339.47	$ 3,614.62	$ 5,081.04	$ 1,407.62	$ 3,107.82	$ 4,808.02	$ 6,763.25	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 165.17**	**$ 377.70**	**$ 802.75**	**$ 1,227.80**	**$ 1,716.61**	**$ 721.01**	**$ 1,571.11**	**$ 2,421.21**	**$ 3,398.82**	**$ 1,064.32**	**$ 2,339.47**	**$ 3,614.62**	**$ 5,081.04**	**$ 1,407.62**	**$ 3,107.82**	**$ 4,808.02**	**$ 6,763.25**	
% Increase	**38.34%**	**13.36%**	**5.52%**	**3.33%**	**2.18%**	**12.23%**	**4.91%**	**2.91%**	**1.88%**	**11.83%**	**4.70%**	**2.77%**	**1.78%**	**11.63%**	**4.60%**	**2.70%**	**1.73%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS-MEDIUM - THREE PHASE - NON TIME OF DAY
With Demands 250-400 Kw
At Average Levels of kWh Use

KW Demand															
Total kW	250	250	250	250	250	250	250	250	400	400	400	400	400	400	400
Hrs Use	0	100	200	300	400	500	600	730	100	200	300	400	500	600	730
REACTIVE DEMAND															
rkVA	14	14	14	14	14	14	14	14	23	23	23	23	23	23	23
ENERGY USAGE															
Monthly Energy Usage	0	25,000	50,000	75,000	100,000	125,000	150,000	182,500	40,000	80,000	120,000	160,000	200,000	240,000	292,000
Total Energy Usage	0	25,000	50,000	75,000	100,000	125,000	150,000	182,500	40,000	80,000	120,000	160,000	200,000	240,000	292,000

UNBUNDLED RATES - CURRENT

NUG Charge															
All kWh @ -0.002 ¢/kWh	$ -	$ (0.50)	$ (1.00)	$ (1.50)	$ (2.00)	$ (2.50)	$ (3.00)	$ (3.65)	$ (0.80)	$ (1.60)	$ (2.40)	$ (3.20)	$ (4.00)	$ (4.80)	$ (5.84)
Distribution															
Distribution Charge @ $21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52
All kW @ $3.82/kW	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 1,528.00	$ 1,528.00	$ 1,528.00	$ 1,528.00	$ 1,528.00	$ 1,528.00	$ 1,528.00
All kWh @ 0.050 ¢/kWh	$ -	$ 12.50	$ 25.00	$ 37.50	$ 50.00	$ 62.50	$ 75.00	$ 91.25	$ 20.00	$ 40.00	$ 60.00	$ 80.00	$ 100.00	$ 120.00	$ 146.00
Sub-Total	$ 976.52	$ 989.02	$ 1,001.52	$ 1,014.02	$ 1,026.52	$ 1,039.02	$ 1,051.52	$ 1,067.77	$ 1,569.52	$ 1,589.52	$ 1,609.52	$ 1,629.52	$ 1,649.52	$ 1,669.52	$ 1,695.52
Riders															
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Universal Service Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 46.25	$ 92.50	$ 138.75	$ 185.00	$ 231.25	$ 277.50	$ 337.63	$ 74.00	$ 148.00	$ 222.00	$ 296.00	$ 370.00	$ 444.00	$ 540.20
Smart Meter Charge @ $2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 62.00	$ 124.00	$ 186.00	$ 248.00	$ 310.00	$ 372.00	$ 452.60	$ 99.20	$ 198.40	$ 297.60	$ 396.80	$ 496.00	$ 595.20	$ 724.16
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 5.50	$ 11.00	$ 16.50	$ 22.00	$ 27.50	$ 33.00	$ 40.15	$ 8.80	$ 17.60	$ 26.40	$ 35.20	$ 44.00	$ 52.80	$ 64.24
Sub-Total	$ 2.38	$ 116.13	$ 229.88	$ 343.63	$ 457.38	$ 571.13	$ 684.88	$ 832.76	$ 184.38	$ 366.38	$ 548.38	$ 730.38	$ 912.38	$ 1,094.38	$ 1,330.98
PTC Charge															
All kWh @ $ 0.08048 /kWh	$ -	$ 2,012.00	$ 4,024.00	$ 6,036.00	$ 8,048.00	$ 10,060.00	$ 12,072.00	$ 14,687.60	$ 3,219.20	$ 6,438.40	$ 9,657.60	$ 12,876.80	$ 16,096.00	$ 19,315.20	$ 23,500.16
Sub Total	$ 978.90	$ 3,116.65	$ 5,254.40	$ 7,392.15	$ 9,529.90	$ 11,667.65	$ 13,805.40	$ 16,584.48	$ 4,972.30	$ 8,392.70	$ 11,813.10	$ 15,233.50	$ 18,653.90	$ 22,074.30	$ 26,520.82
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 978.90**	**$ 3,116.65**	**$ 5,254.40**	**$ 7,392.15**	**$ 9,529.90**	**$ 11,667.65**	**$ 13,805.40**	**$ 16,584.48**	**$ 4,972.30**	**$ 8,392.70**	**$ 11,813.10**	**$ 15,233.50**	**$ 18,653.90**	**$ 22,074.30**	**$ 26,520.82**

UNBUNDLED RATES - PROPOSED

NUG Charge															
All kWh @ -0.002 ¢/kWh	$ -	$ (0.50)	$ (1.00)	$ (1.50)	$ (2.00)	$ (2.50)	$ (3.00)	$ (3.65)	$ (0.80)	$ (1.60)	$ (2.40)	$ (3.20)	$ (4.00)	$ (4.80)	$ (5.84)
Distribution															
Distribution Charge @ $34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39
All kW @ $5.22/kW	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 2,088.00	$ 2,088.00	$ 2,088.00	$ 2,088.00	$ 2,088.00	$ 2,088.00	$ 2,088.00
All rkVA @$ 0.20 /rkVA	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 4.54	$ 4.54	$ 4.54	$ 4.54	$ 4.54	$ 4.54	$ 4.54
Sub-Total	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 2,126.93	$ 2,126.93	$ 2,126.93	$ 2,126.93	$ 2,126.93	$ 2,126.93	$ 2,126.93
Riders															
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Universal Service Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 46.25	$ 92.50	$ 138.75	$ 185.00	$ 231.25	$ 277.50	$ 337.63	$ 74.00	$ 148.00	$ 222.00	$ 296.00	$ 370.00	$ 444.00	$ 540.20
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 62.00	$ 124.00	$ 186.00	$ 248.00	$ 310.00	$ 372.00	$ 452.60	$ 99.20	$ 198.40	$ 297.60	$ 396.80	$ 496.00	$ 595.20	$ 724.16
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 5.50	$ 11.00	$ 16.50	$ 22.00	$ 27.50	$ 33.00	$ 40.15	$ 8.80	$ 17.60	$ 26.40	$ 35.20	$ 44.00	$ 52.80	$ 64.24
Sub-Total	$ -	$ 113.75	$ 227.50	$ 341.25	$ 455.00	$ 568.75	$ 682.50	$ 830.38	$ 182.00	$ 364.00	$ 546.00	$ 728.00	$ 910.00	$ 1,092.00	$ 1,328.60
PTC Charge															
All kWh @ $ 0.08048 /kWh	$ -	$ 2,012.00	$ 4,024.00	$ 6,036.00	$ 8,048.00	$ 10,060.00	$ 12,072.00	$ 14,687.60	$ 3,219.20	$ 6,438.40	$ 9,657.60	$ 12,876.80	$ 16,096.00	$ 19,315.20	$ 23,500.16
Sub Total	$ 1,342.23	$ 3,467.48	$ 5,592.73	$ 7,717.98	$ 9,843.23	$ 11,968.48	$ 14,093.73	$ 16,856.55	$ 5,527.33	$ 8,927.73	$ 12,328.13	$ 15,728.53	$ 19,128.93	$ 22,529.33	$ 26,949.85
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 1,342.23**	**$ 3,467.48**	**$ 5,592.73**	**$ 7,717.98**	**$ 9,843.23**	**$ 11,968.48**	**$ 14,093.73**	**$ 16,856.55**	**$ 5,527.33**	**$ 8,927.73**	**$ 12,328.13**	**$ 15,728.53**	**$ 19,128.93**	**$ 22,529.33**	**$ 26,949.85**
% Increase	**37.12%**	**11.26%**	**6.44%**	**4.41%**	**3.29%**	**2.58%**	**2.09%**	**1.64%**	**11.16%**	**6.37%**	**4.36%**	**3.25%**	**2.55%**	**2.06%**	**1.62%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS-MEDIUM - THREE PHASE - 12 HOUR ON PEAK TIME OF DAY vs RATE GS MEDIUM
With Demands 25-100 KW
At Average Levels of kWh Use

KW Demand																		
Total kW	25	25	25	25	25	50	50	50	50	75	75	75	75	100	100	100	100	
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730	
REACTIVE DEMAND																		
rkVA	1	1	1	1	1	3	3	3	3	4	4	4	4	6	6	6	6	
ENERGY USAGE																		
Monthly Energy Usage	0	2,500	7,500	12,500	18,250	5,000	15,000	25,000	36,500	7,500	22,500	37,500	54,750	10,000	30,000	50,000	73,000	
Total Energy Usage	0	2,500	7,500	12,500	18,250	5,000	15,000	25,000	36,500	7,500	22,500	37,500	54,750	10,000	30,000	50,000	73,000	
UNBUNDLED RATES - CURRENT																		
NUG Charge																		
All kWh @ -0.002 ¢/kWh	$ -	$ (0.05)	$ (0.15)	$ (0.25)	$ (0.37)	$ (0.10)	$ (0.30)	$ (0.50)	$ (0.73)	$ (0.15)	$ (0.45)	$ (0.75)	$ (1.10)	$ (0.20)	$ (0.60)	$ (1.00)	$ (1.46)	
Distribution																		
Distribution Charge @ $21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	
All kW @ $3.82/kW	$ 95.50	$ 95.50	$ 95.50	$ 95.50	$ 95.50	$ 191.00	$ 191.00	$ 191.00	$ 191.00	$ 286.50	$ 286.50	$ 286.50	$ 286.50	$ 382.00	$ 382.00	$ 382.00	$ 382.00	
All kWh @ 0.050 ¢/kWh	$ -	$ 1.25	$ 3.75	$ 6.25	$ 9.13	$ 2.50	$ 7.50	$ 12.50	$ 18.25	$ 3.75	$ 11.25	$ 18.75	$ 27.38	$ 5.00	$ 15.00	$ 25.00	$ 36.50	
Sub-Total	$ 117.02	$ 118.27	$ 120.77	$ 123.27	$ 126.15	$ 215.02	$ 220.02	$ 225.02	$ 230.77	$ 311.77	$ 319.27	$ 326.77	$ 335.40	$ 408.52	$ 418.52	$ 428.52	$ 440.02	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 4.63	$ 13.88	$ 23.13	$ 33.76	$ 9.25	$ 27.75	$ 46.25	$ 67.53	$ 13.88	$ 41.63	$ 69.38	$ 101.29	$ 18.50	$ 55.50	$ 92.50	$ 135.05	
Smart Meter Charge @ $2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 6.20	$ 18.60	$ 31.00	$ 45.26	$ 12.40	$ 37.20	$ 62.00	$ 90.52	$ 18.60	$ 55.80	$ 93.00	$ 135.78	$ 24.80	$ 74.40	$ 124.00	$ 181.04	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.55	$ 1.65	$ 2.75	$ 4.02	$ 1.10	$ 3.30	$ 5.50	$ 8.03	$ 1.65	$ 4.95	$ 8.25	$ 12.05	$ 2.20	$ 6.60	$ 11.00	$ 16.06	
Sub-Total	$ 2.38	$ 13.76	$ 36.51	$ 59.26	$ 85.42	$ 25.13	$ 70.63	$ 116.13	$ 168.46	$ 36.51	$ 104.76	$ 173.01	$ 251.49	$ 47.88	$ 138.88	$ 229.88	$ 334.53	
PTC Charge																		
All kWh @ $ 0.08048 /kWh	$ -	$ 201.20	$ 603.60	$ 1,006.00	$ 1,468.76	$ 402.40	$ 1,207.20	$ 2,012.00	$ 2,937.52	$ 603.60	$ 1,810.80	$ 3,018.00	$ 4,406.28	$ 804.80	$ 2,414.40	$ 4,024.00	$ 5,875.04	
Sub Total	$ 119.40	$ 333.18	$ 760.73	$ 1,188.28	$ 1,679.96	$ 642.45	$ 1,497.55	$ 2,352.65	$ 3,336.02	$ 951.73	$ 2,234.38	$ 3,517.03	$ 4,992.07	$ 1,261.00	$ 2,971.20	$ 4,681.40	$ 6,648.13	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 119.40**	**$ 333.18**	**$ 760.73**	**$ 1,188.28**	**$ 1,679.96**	**$ 642.45**	**$ 1,497.55**	**$ 2,352.65**	**$ 3,336.02**	**$ 951.73**	**$ 2,234.38**	**$ 3,517.03**	**$ 4,992.07**	**$ 1,261.00**	**$ 2,971.20**	**$ 4,681.40**	**$ 6,648.13**	
UNBUNDLED RATES - PROPOSED																		
NUG Charge																		
All kWh @ -0.002 ¢/kWh	$ -	$ (0.05)	$ (0.15)	$ (0.25)	$ (0.37)	$ (0.10)	$ (0.30)	$ (0.50)	$ (0.73)	$ (0.15)	$ (0.45)	$ (0.75)	$ (1.10)	$ (0.20)	$ (0.60)	$ (1.00)	$ (1.46)	
Distribution																		
Distribution Charge @ $34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	
All kW @ $5.22/kW	$ 130.50	$ 130.50	$ 130.50	$ 130.50	$ 130.50	$ 261.00	$ 261.00	$ 261.00	$ 261.00	$ 391.50	$ 391.50	$ 391.50	$ 391.50	$ 522.00	$ 522.00	$ 522.00	$ 522.00	
All rkVA @$ 0.20 /rkVA	$ 0.28	$ 0.28	$ 0.28	$ 0.28	$ 0.28	$ 0.57	$ 0.57	$ 0.57	$ 0.57	$ 0.85	$ 0.85	$ 0.85	$ 0.85	$ 1.13	$ 1.13	$ 1.13	$ 1.13	
Sub-Total	$ 165.17	$ 165.17	$ 165.17	$ 165.17	$ 165.17	$ 295.96	$ 295.96	$ 295.96	$ 295.96	$ 426.74	$ 426.74	$ 426.74	$ 426.74	$ 557.52	$ 557.52	$ 557.52	$ 557.52	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 4.63	$ 13.88	$ 23.13	$ 33.76	$ 9.25	$ 27.75	$ 46.25	$ 67.53	$ 13.88	$ 41.63	$ 69.38	$ 101.29	$ 18.50	$ 55.50	$ 92.50	$ 135.05	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 6.20	$ 18.60	$ 31.00	$ 45.26	$ 12.40	$ 37.20	$ 62.00	$ 90.52	$ 18.60	$ 55.80	$ 93.00	$ 135.78	$ 24.80	$ 74.40	$ 124.00	$ 181.04	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.55	$ 1.65	$ 2.75	$ 4.02	$ 1.10	$ 3.30	$ 5.50	$ 8.03	$ 1.65	$ 4.95	$ 8.25	$ 12.05	$ 2.20	$ 6.60	$ 11.00	$ 16.06	
Sub-Total	$ -	$ 11.38	$ 34.13	$ 56.88	$ 83.04	$ 22.75	$ 68.25	$ 113.75	$ 166.08	$ 34.13	$ 102.38	$ 170.63	$ 249.11	$ 45.50	$ 136.50	$ 227.50	$ 332.15	
PTC Charge																		
All kWh @ $ 0.08048 /kWh	$ -	$ 201.20	$ 603.60	$ 1,006.00	$ 1,468.76	$ 402.40	$ 1,207.20	$ 2,012.00	$ 2,937.52	$ 603.60	$ 1,810.80	$ 3,018.00	$ 4,406.28	$ 804.80	$ 2,414.40	$ 4,024.00	$ 5,875.04	
Sub Total	$ 165.17	$ 377.70	$ 802.75	$ 1,227.80	$ 1,716.61	$ 721.01	$ 1,571.11	$ 2,421.21	$ 3,398.82	$ 1,064.32	$ 2,339.47	$ 3,614.62	$ 5,081.04	$ 1,407.62	$ 3,107.82	$ 4,808.02	$ 6,763.25	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 165.17**	**$ 377.70**	**$ 802.75**	**$ 1,227.80**	**$ 1,716.61**	**$ 721.01**	**$ 1,571.11**	**$ 2,421.21**	**$ 3,398.82**	**$ 1,064.32**	**$ 2,339.47**	**$ 3,614.62**	**$ 5,081.04**	**$ 1,407.62**	**$ 3,107.82**	**$ 4,808.02**	**$ 6,763.25**	
% Increase	**38.34%**	**13.36%**	**5.52%**	**3.33%**	**2.18%**	**12.23%**	**4.91%**	**2.91%**	**1.88%**	**11.83%**	**4.70%**	**2.77%**	**1.78%**	**11.63%**	**4.60%**	**2.70%**	**1.73%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS-MEDIUM - THREE PHASE - 12 HOUR ON PEAK TIME OF DAY vs RATE GS MEDIUM
With Demands 250-400 Kw
At Average Levels of kWh Use

KW Demand															
Total kW	250	250	250	250	250	250	250	250	400	400	400	400	400	400	400
Hrs Use	0	100	200	300	400	500	600	730	100	200	300	400	500	600	730
REACTIVE DEMAND															
rkVA	14	14	14	14	14	14	14	14	23	23	23	23	23	23	23
ENERGY USAGE															
Monthly Energy Usage	0	25,000	50,000	75,000	100,000	125,000	150,000	182,500	40,000	80,000	120,000	160,000	200,000	240,000	292,000
Total Energy Usage	0	25,000	50,000	75,000	100,000	125,000	150,000	182,500	40,000	80,000	120,000	160,000	200,000	240,000	292,000

UNBUNDLED RATES - CURRENT

NUG Charge															
All kWh @ -0.002 ¢/kWh	$ -	$ (0.50)	$ (1.00)	$ (1.50)	$ (2.00)	$ (2.50)	$ (3.00)	$ (3.65)	$ (0.80)	$ (1.60)	$ (2.40)	$ (3.20)	$ (4.00)	$ (4.80)	$ (5.84)
Distribution															
Distribution Charge @ $21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52
All kW @ $3.82/kW	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 1,528.00	$ 1,528.00	$ 1,528.00	$ 1,528.00	$ 1,528.00	$ 1,528.00	$ 1,528.00
All kWh @ 0.050 ¢/kWh	$ -	$ 12.50	$ 25.00	$ 37.50	$ 50.00	$ 62.50	$ 75.00	$ 91.25	$ 20.00	$ 40.00	$ 60.00	$ 80.00	$ 100.00	$ 120.00	$ 146.00
Sub-Total	$ 976.52	$ 989.02	$ 1,001.52	$ 1,014.02	$ 1,026.52	$ 1,039.02	$ 1,051.52	$ 1,067.77	$ 1,569.52	$ 1,589.52	$ 1,609.52	$ 1,629.52	$ 1,649.52	$ 1,669.52	$ 1,695.52
Riders															
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 46.25	$ 92.50	$ 138.75	$ 185.00	$ 231.25	$ 277.50	$ 337.63	$ 74.00	$ 148.00	$ 222.00	$ 296.00	$ 370.00	$ 444.00	$ 540.20
Smart Meter Charge @ $2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 62.00	$ 124.00	$ 186.00	$ 248.00	$ 310.00	$ 372.00	$ 452.60	$ 99.20	$ 198.40	$ 297.60	$ 396.80	$ 496.00	$ 595.20	$ 724.16
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 5.50	$ 11.00	$ 16.50	$ 22.00	$ 27.50	$ 33.00	$ 40.15	$ 8.80	$ 17.60	$ 26.40	$ 35.20	$ 44.00	$ 52.80	$ 64.24
Sub-Total	$ 2.38	$ 116.13	$ 229.88	$ 343.63	$ 457.38	$ 571.13	$ 684.88	$ 832.76	$ 184.38	$ 366.38	$ 548.38	$ 730.38	$ 912.38	$ 1,094.38	$ 1,330.98
PTC Charge															
All kWh @ $ 0.08048 /kWh	$ -	$ 2,012.00	$ 4,024.00	$ 6,036.00	$ 8,048.00	$ 10,060.00	$ 12,072.00	$ 14,687.60	$ 3,219.20	$ 6,438.40	$ 9,657.60	$ 12,876.80	$ 16,096.00	$ 19,315.20	$ 23,500.16
Sub Total	$ 978.90	$ 3,116.65	$ 5,254.40	$ 7,392.15	$ 9,529.90	$ 11,667.65	$ 13,805.40	$ 16,584.48	$ 4,972.30	$ 8,392.70	$ 11,813.10	$ 15,233.50	$ 18,653.90	$ 22,074.30	$ 26,520.82
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 978.90**	**$ 3,116.65**	**$ 5,254.40**	**$ 7,392.15**	**$ 9,529.90**	**$ 11,667.65**	**$ 13,805.40**	**$ 16,584.48**	**$ 4,972.30**	**$ 8,392.70**	**$ 11,813.10**	**$ 15,233.50**	**$ 18,653.90**	**$ 22,074.30**	**$ 26,520.82**

UNBUNDLED RATES - PROPOSED

NUG Charge															
All kWh @ -0.002 ¢/kWh	$ -	$ (0.50)	$ (1.00)	$ (1.50)	$ (2.00)	$ (2.50)	$ (3.00)	$ (3.65)	$ (0.80)	$ (1.60)	$ (2.40)	$ (3.20)	$ (4.00)	$ (4.80)	$ (5.84)
Distribution															
Distribution Charge @ $34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39
All kW @ $5.22/kW	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 2,088.00	$ 2,088.00	$ 2,088.00	$ 2,088.00	$ 2,088.00	$ 2,088.00	$ 2,088.00
All rkVA @$ 0.20 /rkVA	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 4.54	$ 4.54	$ 4.54	$ 4.54	$ 4.54	$ 4.54	$ 4.54
Sub-Total	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 2,126.93	$ 2,126.93	$ 2,126.93	$ 2,126.93	$ 2,126.93	$ 2,126.93	$ 2,126.93
Riders															
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 46.25	$ 92.50	$ 138.75	$ 185.00	$ 231.25	$ 277.50	$ 337.63	$ 74.00	$ 148.00	$ 222.00	$ 296.00	$ 370.00	$ 444.00	$ 540.20
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 62.00	$ 124.00	$ 186.00	$ 248.00	$ 310.00	$ 372.00	$ 452.60	$ 99.20	$ 198.40	$ 297.60	$ 396.80	$ 496.00	$ 595.20	$ 724.16
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 5.50	$ 11.00	$ 16.50	$ 22.00	$ 27.50	$ 33.00	$ 40.15	$ 8.80	$ 17.60	$ 26.40	$ 35.20	$ 44.00	$ 52.80	$ 64.24
Sub-Total	$ -	$ 113.75	$ 227.50	$ 341.25	$ 455.00	$ 568.75	$ 682.50	$ 830.38	$ 182.00	$ 364.00	$ 546.00	$ 728.00	$ 910.00	$ 1,092.00	$ 1,328.60
PTC Charge															
All kWh @ $ 0.08048 /kWh	$ -	$ 2,012.00	$ 4,024.00	$ 6,036.00	$ 8,048.00	$ 10,060.00	$ 12,072.00	$ 14,687.60	$ 3,219.20	$ 6,438.40	$ 9,657.60	$ 12,876.80	$ 16,096.00	$ 19,315.20	$ 23,500.16
Sub Total	$ 1,342.23	$ 3,467.48	$ 5,592.73	$ 7,717.98	$ 9,843.23	$ 11,968.48	$ 14,093.73	$ 16,856.55	$ 5,527.33	$ 8,927.73	$ 12,328.13	$ 15,728.53	$ 19,128.93	$ 22,529.33	$ 26,949.85
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 1,342.23**	**$ 3,467.48**	**$ 5,592.73**	**$ 7,717.98**	**$ 9,843.23**	**$ 11,968.48**	**$ 14,093.73**	**$ 16,856.55**	**$ 5,527.33**	**$ 8,927.73**	**$ 12,328.13**	**$ 15,728.53**	**$ 19,128.93**	**$ 22,529.33**	**$ 26,949.85**
% Increase	**37.12%**	**11.26%**	**6.44%**	**4.41%**	**3.29%**	**2.58%**	**2.09%**	**1.64%**	**11.16%**	**6.37%**	**4.36%**	**3.25%**	**2.55%**	**2.06%**	**1.62%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS-MEDIUM - THREE PHASE - 8 HOUR ON PEAK TIME OF DAY
With Demands 25-100 KW
At Average Levels of kWh Use

KW Demand																		
Total kW	25	25	25	25	25	50	50	50	50	75	75	75	75	100	100	100	100	
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730	
REACTIVE DEMAND																		
rkVA	1	1	1	1	1	3	3	3	3	4	4	4	4	6	6	6	6	
ENERGY USAGE																		
Monthly Energy Usage	0	2,500	7,500	12,500	18,250	5,000	15,000	25,000	36,500	7,500	22,500	37,500	54,750	10,000	30,000	50,000	73,000	
Total Energy Usage	0	2,500	7,500	12,500	18,250	5,000	15,000	25,000	36,500	7,500	22,500	37,500	54,750	10,000	30,000	50,000	73,000	

UNBUNDLED RATES - CURRENT

NUG Charge																		
All kWh @ -0.002 ¢/kWh	$ -	$ (0.05)	$ (0.15)	$ (0.25)	$ (0.37)	$ (0.10)	$ (0.30)	$ (0.50)	$ (0.73)	$ (0.15)	$ (0.45)	$ (0.75)	$ (1.10)	$ (0.20)	$ (0.60)	$ (1.00)	$ (1.46)	
Distribution																		
Distribution Charge @ $21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	
All kW @ $3.82/kW	$ 95.50	$ 95.50	$ 95.50	$ 95.50	$ 95.50	$ 191.00	$ 191.00	$ 191.00	$ 191.00	$ 286.50	$ 286.50	$ 286.50	$ 286.50	$ 382.00	$ 382.00	$ 382.00	$ 382.00	
All kWh @ 0.050 ¢/kWh	$ -	$ 1.25	$ 3.75	$ 6.25	$ 9.13	$ 2.50	$ 7.50	$ 12.50	$ 18.25	$ 3.75	$ 11.25	$ 18.75	$ 27.38	$ 5.00	$ 15.00	$ 25.00	$ 36.50	
Sub-Total	$ 117.02	$ 118.27	$ 120.77	$ 123.27	$ 126.15	$ 215.02	$ 220.02	$ 225.02	$ 230.77	$ 311.77	$ 319.27	$ 326.77	$ 335.40	$ 408.52	$ 418.52	$ 428.52	$ 440.02	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 4.63	$ 13.88	$ 23.13	$ 33.76	$ 9.25	$ 27.75	$ 46.25	$ 67.53	$ 13.88	$ 41.63	$ 69.38	$ 101.29	$ 18.50	$ 55.50	$ 92.50	$ 135.05	
Smart Meter Charge @ $2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 6.20	$ 18.60	$ 31.00	$ 45.26	$ 12.40	$ 37.20	$ 62.00	$ 90.52	$ 18.60	$ 55.80	$ 93.00	$ 135.78	$ 24.80	$ 74.40	$ 124.00	$ 181.04	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.55	$ 1.65	$ 2.75	$ 4.02	$ 1.10	$ 3.30	$ 5.50	$ 8.03	$ 1.65	$ 4.95	$ 8.25	$ 12.05	$ 2.20	$ 6.60	$ 11.00	$ 16.06	
Sub-Total	$ 2.38	$ 13.76	$ 36.51	$ 59.26	$ 85.42	$ 25.13	$ 70.63	$ 116.13	$ 168.46	$ 36.51	$ 104.76	$ 173.01	$ 251.49	$ 47.88	$ 138.88	$ 229.88	$ 334.53	
PTC Charge																		
All kWh @ $ 0.08048 /kWh	$ -	$ 201.20	$ 603.60	$ 1,006.00	$ 1,468.76	$ 402.40	$ 1,207.20	$ 2,012.00	$ 2,937.52	$ 603.60	$ 1,810.80	$ 3,018.00	$ 4,406.28	$ 804.80	$ 2,414.40	$ 4,024.00	$ 5,875.04	
Sub Total	$ 119.40	$ 333.18	$ 760.73	$ 1,188.28	$ 1,679.96	$ 642.45	$ 1,497.55	$ 2,352.65	$ 3,336.02	$ 951.73	$ 2,234.38	$ 3,517.03	$ 4,992.07	$ 1,261.00	$ 2,971.20	$ 4,681.40	$ 6,648.13	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 119.40**	**$ 333.18**	**$ 760.73**	**$ 1,188.28**	**$ 1,679.96**	**$ 642.45**	**$ 1,497.55**	**$ 2,352.65**	**$ 3,336.02**	**$ 951.73**	**$ 2,234.38**	**$ 3,517.03**	**$ 4,992.07**	**$ 1,261.00**	**$ 2,971.20**	**$ 4,681.40**	**$ 6,648.13**	

UNBUNDLED RATES - PROPOSED

NUG Charge																		
All kWh @ -0.002 ¢/kWh	$ -	$ (0.05)	$ (0.15)	$ (0.25)	$ (0.37)	$ (0.10)	$ (0.30)	$ (0.50)	$ (0.73)	$ (0.15)	$ (0.45)	$ (0.75)	$ (1.10)	$ (0.20)	$ (0.60)	$ (1.00)	$ (1.46)	
Distribution																		
Distribution Charge @ $34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	
All kW @ $5.22/kW	$ 130.50	$ 130.50	$ 130.50	$ 130.50	$ 130.50	$ 261.00	$ 261.00	$ 261.00	$ 261.00	$ 391.50	$ 391.50	$ 391.50	$ 391.50	$ 522.00	$ 522.00	$ 522.00	$ 522.00	
All rkVA @$ 0.20 /rkVA	$ 0.28	$ 0.28	$ 0.28	$ 0.28	$ 0.28	$ 0.57	$ 0.57	$ 0.57	$ 0.57	$ 0.85	$ 0.85	$ 0.85	$ 0.85	$ 1.13	$ 1.13	$ 1.13	$ 1.13	
Sub-Total	$ 165.17	$ 165.17	$ 165.17	$ 165.17	$ 165.17	$ 295.96	$ 295.96	$ 295.96	$ 295.96	$ 426.74	$ 426.74	$ 426.74	$ 426.74	$ 557.52	$ 557.52	$ 557.52	$ 557.52	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 4.63	$ 13.88	$ 23.13	$ 33.76	$ 9.25	$ 27.75	$ 46.25	$ 67.53	$ 13.88	$ 41.63	$ 69.38	$ 101.29	$ 18.50	$ 55.50	$ 92.50	$ 135.05	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 6.20	$ 18.60	$ 31.00	$ 45.26	$ 12.40	$ 37.20	$ 62.00	$ 90.52	$ 18.60	$ 55.80	$ 93.00	$ 135.78	$ 24.80	$ 74.40	$ 124.00	$ 181.04	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.55	$ 1.65	$ 2.75	$ 4.02	$ 1.10	$ 3.30	$ 5.50	$ 8.03	$ 1.65	$ 4.95	$ 8.25	$ 12.05	$ 2.20	$ 6.60	$ 11.00	$ 16.06	
Sub-Total	$ -	$ 11.38	$ 34.13	$ 56.88	$ 83.04	$ 22.75	$ 68.25	$ 113.75	$ 166.08	$ 34.13	$ 102.38	$ 170.63	$ 249.11	$ 45.50	$ 136.50	$ 227.50	$ 332.15	
PTC Charge																		
All kWh @ $ 0.08048 /kWh	$ -	$ 201.20	$ 603.60	$ 1,006.00	$ 1,468.76	$ 402.40	$ 1,207.20	$ 2,012.00	$ 2,937.52	$ 603.60	$ 1,810.80	$ 3,018.00	$ 4,406.28	$ 804.80	$ 2,414.40	$ 4,024.00	$ 5,875.04	
Sub Total	$ 165.17	$ 377.70	$ 802.75	$ 1,227.80	$ 1,716.61	$ 721.01	$ 1,571.11	$ 2,421.21	$ 3,398.82	$ 1,064.32	$ 2,339.47	$ 3,614.62	$ 5,081.04	$ 1,407.62	$ 3,107.82	$ 4,808.02	$ 6,763.25	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 165.17**	**$ 377.70**	**$ 802.75**	**$ 1,227.80**	**$ 1,716.61**	**$ 721.01**	**$ 1,571.11**	**$ 2,421.21**	**$ 3,398.82**	**$ 1,064.32**	**$ 2,339.47**	**$ 3,614.62**	**$ 5,081.04**	**$ 1,407.62**	**$ 3,107.82**	**$ 4,808.02**	**$ 6,763.25**	
% Increase	**38.34%**	**13.36%**	**5.52%**	**3.33%**	**2.18%**	**12.23%**	**4.91%**	**2.91%**	**1.88%**	**11.83%**	**4.70%**	**2.77%**	**1.78%**	**11.63%**	**4.60%**	**2.70%**	**1.73%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS-MEDIUM - THREE PHASE - 8 HOUR ON PEAK TIME OF DAY
With Demands 250-400 KW
At Average Levels of kWh Use

KW Demand																
Total kW	250	250	250	250	250	250	250	250	400	400	400	400	400	400	400	
Hrs Use	0	100	200	300	400	500	600	730	100	200	300	400	500	600	730	
REACTIVE DEMAND																
rkVA	14	14	14	14	14	14	14	14	23	23	23	23	23	23	23	
ENERGY USAGE																
Monthly Energy Usage	0	25,000	50,000	75,000	100,000	125,000	150,000	182,500	40,000	80,000	120,000	160,000	200,000	240,000	292,000	
Total Energy Usage	0	25,000	50,000	75,000	100,000	125,000	150,000	182,500	40,000	80,000	120,000	160,000	200,000	240,000	292,000	

UNBUNDLED RATES - CURRENT

NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (0.50)	$ (1.00)	$ (1.50)	$ (2.00)	$ (2.50)	$ (3.00)	$ (3.65)	$ (0.80)	$ (1.60)	$ (2.40)	$ (3.20)	$ (4.00)	$ (4.80)	$ (5.84)	
Distribution																
Distribution Charge @ $21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	$ 21.52	
All kW @ $3.82/kW	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 955.00	$ 1,528.00	$ 1,528.00	$ 1,528.00	$ 1,528.00	$ 1,528.00	$ 1,528.00	$ 1,528.00	
All kWh @ 0.050 ¢/kWh	$ -	$ 12.50	$ 25.00	$ 37.50	$ 50.00	$ 62.50	$ 75.00	$ 91.25	$ 20.00	$ 40.00	$ 60.00	$ 80.00	$ 100.00	$ 120.00	$ 146.00	
Sub-Total	$ 976.52	$ 989.02	$ 1,001.52	$ 1,014.02	$ 1,026.52	$ 1,039.02	$ 1,051.52	$ 1,067.77	$ 1,569.52	$ 1,589.52	$ 1,609.52	$ 1,629.52	$ 1,649.52	$ 1,669.52	$ 1,695.52	
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 46.25	$ 92.50	$ 138.75	$ 185.00	$ 231.25	$ 277.50	$ 337.63	$ 74.00	$ 148.00	$ 222.00	$ 296.00	$ 370.00	$ 444.00	$ 540.20	
Smart Meter Charge @ $2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	$ 2.38	
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 62.00	$ 124.00	$ 186.00	$ 248.00	$ 310.00	$ 372.00	$ 452.60	$ 99.20	$ 198.40	$ 297.60	$ 396.80	$ 496.00	$ 595.20	$ 724.16	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 5.50	$ 11.00	$ 16.50	$ 22.00	$ 27.50	$ 33.00	$ 40.15	$ 8.80	$ 17.60	$ 26.40	$ 35.20	$ 44.00	$ 52.80	$ 64.24	
Sub-Total	$ 2.38	$ 116.13	$ 229.88	$ 343.63	$ 457.38	$ 571.13	$ 684.88	$ 832.76	$ 184.38	$ 366.38	$ 548.38	$ 730.38	$ 912.38	$ 1,094.38	$ 1,330.98	
PTC Charge																
All kWh @ $ 0.08048 /kWh	$ -	$ 2,012.00	$ 4,024.00	$ 6,036.00	$ 8,048.00	$ 10,060.00	$ 12,072.00	$ 14,687.60	$ 3,219.20	$ 6,438.40	$ 9,657.60	$ 12,876.80	$ 16,096.00	$ 19,315.20	$ 23,500.16	
Sub Total	$ 978.90	$ 3,116.65	$ 5,254.40	$ 7,392.15	$ 9,529.90	$ 11,667.65	$ 13,805.40	$ 16,584.48	$ 4,972.30	$ 8,392.70	$ 11,813.10	$ 15,233.50	$ 18,653.90	$ 22,074.30	$ 26,520.82	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 978.90**	**$ 3,116.65**	**$ 5,254.40**	**$ 7,392.15**	**$ 9,529.90**	**$ 11,667.65**	**$ 13,805.40**	**$ 16,584.48**	**$ 4,972.30**	**$ 8,392.70**	**$ 11,813.10**	**$ 15,233.50**	**$ 18,653.90**	**$ 22,074.30**	**$ 26,520.82**	

UNBUNDLED RATES - PROPOSED

NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (0.50)	$ (1.00)	$ (1.50)	$ (2.00)	$ (2.50)	$ (3.00)	$ (3.65)	$ (0.80)	$ (1.60)	$ (2.40)	$ (3.20)	$ (4.00)	$ (4.80)	$ (5.84)	
Distribution																
Distribution Charge @ $34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	$ 34.39	
All kW @ $5.22/kW	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 1,305.00	$ 2,088.00	$ 2,088.00	$ 2,088.00	$ 2,088.00	$ 2,088.00	$ 2,088.00	$ 2,088.00	
All rkVA @$ 0.20 /rkVA	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 2.84	$ 4.54	$ 4.54	$ 4.54	$ 4.54	$ 4.54	$ 4.54	$ 4.54	
Sub-Total	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 1,342.23	$ 2,126.93	$ 2,126.93	$ 2,126.93	$ 2,126.93	$ 2,126.93	$ 2,126.93	$ 2,126.93	
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ 0.185 ¢/kWh	$ -	$ 46.25	$ 92.50	$ 138.75	$ 185.00	$ 231.25	$ 277.50	$ 337.63	$ 74.00	$ 148.00	$ 222.00	$ 296.00	$ 370.00	$ 444.00	$ 540.20	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @ 0.248 ¢/kWh	$ -	$ 62.00	$ 124.00	$ 186.00	$ 248.00	$ 310.00	$ 372.00	$ 452.60	$ 99.20	$ 198.40	$ 297.60	$ 396.80	$ 496.00	$ 595.20	$ 724.16	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 5.50	$ 11.00	$ 16.50	$ 22.00	$ 27.50	$ 33.00	$ 40.15	$ 8.80	$ 17.60	$ 26.40	$ 35.20	$ 44.00	$ 52.80	$ 64.24	
Sub-Total	$ -	$ 113.75	$ 227.50	$ 341.25	$ 455.00	$ 568.75	$ 682.50	$ 830.38	$ 182.00	$ 364.00	$ 546.00	$ 728.00	$ 910.00	$ 1,092.00	$ 1,328.60	
PTC Charge																
All kWh @ $ 0.08048 /kWh	$ -	$ 2,012.00	$ 4,024.00	$ 6,036.00	$ 8,048.00	$ 10,060.00	$ 12,072.00	$ 14,687.60	$ 3,219.20	$ 6,438.40	$ 9,657.60	$ 12,876.80	$ 16,096.00	$ 19,315.20	$ 23,500.16	
Sub Total	$ 1,342.23	$ 3,467.48	$ 5,592.73	$ 7,717.98	$ 9,843.23	$ 11,968.48	$ 14,093.73	$ 16,856.55	$ 5,527.33	$ 8,927.73	$ 12,328.13	$ 15,728.53	$ 19,128.93	$ 22,529.33	$ 26,949.85	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 1,342.23**	**$ 3,467.48**	**$ 5,592.73**	**$ 7,717.98**	**$ 9,843.23**	**$ 11,968.48**	**$ 14,093.73**	**$ 16,856.55**	**$ 5,527.33**	**$ 8,927.73**	**$ 12,328.13**	**$ 15,728.53**	**$ 19,128.93**	**$ 22,529.33**	**$ 26,949.85**	
% Increase	**37.12%**	**11.26%**	**6.44%**	**4.41%**	**3.29%**	**2.58%**	**2.09%**	**1.64%**	**11.16%**	**6.37%**	**4.36%**	**3.25%**	**2.55%**	**2.06%**	**1.62%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS - LARGE - 12 HOUR ON PEAK TIME OF DAY
With Demands of 500 - 1,000 KW
At Average Levels of kWh Use

KW Demand																
Total kW	500	500	500	500	500	500	750	750	750	750	750	1,000	1,000	1,000	1,000	1,000
Hrs Use	0	200	300	400	500	730	200	300	400	500	730	200	300	400	500	730
REACTIVE DEMAND																
rkVA	300	300	300	300	300	300	450	450	450	450	450	600	600	600	600	600
ENERGY USAGE																
Monthly Energy Usage	0	100,000	150,000	200,000	250,000	365,000	150,000	225,000	300,000	375,000	547,500	200,000	300,000	400,000	500,000	730,000
Total Energy Usage	0	100,000	150,000	200,000	250,000	365,000	150,000	225,000	300,000	375,000	547,500	200,000	300,000	400,000	500,000	730,000
UNBUNDLED RATES - CURRENT																
NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (2.00)	$ (3.00)	$ (4.00)	$ (5.00)	$ (7.30)	$ (3.00)	$ (4.50)	$ (6.00)	$ (7.50)	$ (10.95)	$ (4.00)	$ (6.00)	$ (8.00)	$ (10.00)	$ (14.60)
Distribution																
Distribution Charge @ $60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98
All kW @ $2.43/kW	$ 1,215.00	$ 1,215.00	$ 1,215.00	$ 1,215.00	$ 1,215.00	$ 1,215.00	$ 1,822.50	$ 1,822.50	$ 1,822.50	$ 1,822.50	$ 1,822.50	$ 2,430.00	$ 2,430.00	$ 2,430.00	$ 2,430.00	$ 2,430.00
Sub-Total	$ 1,275.98	$ 1,275.98	$ 1,275.98	$ 1,275.98	$ 1,275.98	$ 1,275.98	$ 1,883.48	$ 1,883.48	$ 1,883.48	$ 1,883.48	$ 1,883.48	$ 2,490.98	$ 2,490.98	$ 2,490.98	$ 2,490.98	$ 2,490.98
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 375.00	$ 375.00	$ 375.00	$ 375.00	$ 375.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00
Smart Meter Charge @ $2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40
Default Service Support Charge @$ 1.053 /kW NSPL	$ 526.50	$ 526.50	$ 526.50	$ 526.50	$ 526.50	$ 526.50	$ 789.75	$ 789.75	$ 789.75	$ 789.75	$ 789.75	$ 1,053.00	$ 1,053.00	$ 1,053.00	$ 1,053.00	$ 1,053.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 22.00	$ 33.00	$ 44.00	$ 55.00	$ 80.30	$ 33.00	$ 49.50	$ 66.00	$ 82.50	$ 120.45	$ 44.00	$ 66.00	$ 88.00	$ 110.00	$ 160.60
Sub-Total	$ 778.90	$ 800.90	$ 811.90	$ 822.90	$ 833.90	$ 859.20	$ 1,200.15	$ 1,216.65	$ 1,233.15	$ 1,249.65	$ 1,287.60	$ 1,599.40	$ 1,621.40	$ 1,643.40	$ 1,665.40	$ 1,716.00
PTC Charge																
All kWh @ $ 0.05442 /kWh	$ -	$ 5,442.00	$ 8,163.00	$ 10,884.00	$ 13,605.00	$ 19,863.30	$ 8,163.00	$ 12,244.50	$ 16,326.00	$ 20,407.50	$ 29,794.95	$ 10,884.00	$ 16,326.00	$ 21,768.00	$ 27,210.00	$ 39,726.60
Sub Total	$ 2,054.88	$ 7,516.88	$ 10,247.88	$ 12,978.88	$ 15,709.88	$ 21,991.18	$ 11,243.63	$ 15,340.13	$ 19,436.63	$ 23,533.13	$ 32,955.08	$ 14,970.38	$ 20,432.38	$ 25,894.38	$ 31,356.38	$ 43,918.98
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 2,054.88**	**$ 7,516.88**	**$ 10,247.88**	**$ 12,978.88**	**$ 15,709.88**	**$ 21,991.18**	**$ 11,243.63**	**$ 15,340.13**	**$ 19,436.63**	**$ 23,533.13**	**$ 32,955.08**	**$ 14,970.38**	**$ 20,432.38**	**$ 25,894.38**	**$ 31,356.38**	**$ 43,918.98**
UNBUNDLED RATES - PROPOSED																
NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (2.00)	$ (3.00)	$ (4.00)	$ (5.00)	$ (7.30)	$ (3.00)	$ (4.50)	$ (6.00)	$ (7.50)	$ (10.95)	$ (4.00)	$ (6.00)	$ (8.00)	$ (10.00)	$ (14.60)
Distribution																
Distribution Charge @ $93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87
All kW @ $3.63/kW	$ 1,815.00	$ 1,815.00	$ 1,815.00	$ 1,815.00	$ 1,815.00	$ 1,815.00	$ 2,722.50	$ 2,722.50	$ 2,722.50	$ 2,722.50	$ 2,722.50	$ 3,630.00	$ 3,630.00	$ 3,630.00	$ 3,630.00	$ 3,630.00
All rkVA @$ 0.20 /rkVA	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 90.00	$ 90.00	$ 90.00	$ 90.00	$ 90.00	$ 120.00	$ 120.00	$ 120.00	$ 120.00	$ 120.00
Sub-Total	$ 1,968.87	$ 1,968.87	$ 1,968.87	$ 1,968.87	$ 1,968.87	$ 1,968.87	$ 2,906.37	$ 2,906.37	$ 2,906.37	$ 2,906.37	$ 2,906.37	$ 3,843.87	$ 3,843.87	$ 3,843.87	$ 3,843.87	$ 3,843.87
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 375.00	$ 375.00	$ 375.00	$ 375.00	$ 375.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @$ 1.053 /kW NSPL	$ 526.50	$ 526.50	$ 526.50	$ 526.50	$ 526.50	$ 526.50	$ 789.75	$ 789.75	$ 789.75	$ 789.75	$ 789.75	$ 1,053.00	$ 1,053.00	$ 1,053.00	$ 1,053.00	$ 1,053.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 22.00	$ 33.00	$ 44.00	$ 55.00	$ 80.30	$ 33.00	$ 49.50	$ 66.00	$ 82.50	$ 120.45	$ 44.00	$ 66.00	$ 88.00	$ 110.00	$ 160.60
Sub-Total	$ 776.50	$ 798.50	$ 809.50	$ 820.50	$ 831.50	$ 856.80	$ 1,197.75	$ 1,214.25	$ 1,230.75	$ 1,247.25	$ 1,285.20	$ 1,597.00	$ 1,619.00	$ 1,641.00	$ 1,663.00	$ 1,713.60
PTC Charge																
All kWh @ $ 0.05442 /kWh	$ -	$ 5,442.00	$ 8,163.00	$ 10,884.00	$ 13,605.00	$ 19,863.30	$ 8,163.00	$ 12,244.50	$ 16,326.00	$ 20,407.50	$ 29,794.95	$ 10,884.00	$ 16,326.00	$ 21,768.00	$ 27,210.00	$ 39,726.60
Sub Total	$ 2,745.37	$ 8,207.37	$ 10,938.37	$ 13,669.37	$ 16,400.37	$ 22,681.67	$ 12,264.12	$ 16,360.62	$ 20,457.12	$ 24,553.62	$ 33,975.57	$ 16,320.87	$ 21,782.87	$ 27,244.87	$ 32,706.87	$ 45,269.47
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 2,745.37**	**$ 8,207.37**	**$ 10,938.37**	**$ 13,669.37**	**$ 16,400.37**	**$ 22,681.67**	**$ 12,264.12**	**$ 16,360.62**	**$ 20,457.12**	**$ 24,553.62**	**$ 33,975.57**	**$ 16,320.87**	**$ 21,782.87**	**$ 27,244.87**	**$ 32,706.87**	**$ 45,269.47**
% Increase	**33.60%**	**9.19%**	**6.74%**	**5.32%**	**4.40%**	**3.14%**	**9.08%**	**6.65%**	**5.25%**	**4.34%**	**3.10%**	**9.02%**	**6.61%**	**5.22%**	**4.31%**	**3.07%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS - LARGE - 12 HOUR ON PEAK TIME OF DAY
With Demands of 1,500 - 3,000 KW
At Average Levels of kWh Use

KW Demand																	
Total kW	1,500	1,500	1,500	1,500	1,500	2,000	2,000	2,000	2,000	2,500	2,500	2,500	2,500	3,000	3,000	3,000	3,000
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730
REACTIVE DEMAND																	
rkVA	900	900	900	900	900	1,200	1,200	1,200	1,200	1,500	1,500	1,500	1,500	1,800	1,800	1,800	1,800
ENERGY USAGE																	
Monthly Energy Usage	0	150,000	450,000	750,000	1,095,000	200,000	600,000	1,000,000	1,460,000	250,000	750,000	1,250,000	1,825,000	300,000	900,000	1,500,000	2,190,000
Total Energy Usage	0	150,000	450,000	750,000	1,095,000	200,000	600,000	1,000,000	1,460,000	250,000	750,000	1,250,000	1,825,000	300,000	900,000	1,500,000	2,190,000

UNBUNDLED RATES - CURRENT

NUG Charge																	
All kWh @ -0.002 ¢/kWh	$ -	$ (3.00)	$ (9.00)	$ (15.00)	$ (21.90)	$ (4.00)	$ (12.00)	$ (20.00)	$ (29.20)	$ (5.00)	$ (15.00)	$ (25.00)	$ (36.50)	$ (6.00)	$ (18.00)	$ (30.00)	$ (43.80)
Distribution																	
Distribution Charge @ $60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98
All kW @ $2.43/kW	$ 3,645.00	$ 3,645.00	$ 3,645.00	$ 3,645.00	$ 3,645.00	$ 4,860.00	$ 4,860.00	$ 4,860.00	$ 4,860.00	$ 6,075.00	$ 6,075.00	$ 6,075.00	$ 6,075.00	$ 7,290.00	$ 7,290.00	$ 7,290.00	$ 7,290.00
Sub-Total	$ 3,705.98	$ 3,705.98	$ 3,705.98	$ 3,705.98	$ 3,705.98	$ 4,920.98	$ 4,920.98	$ 4,920.98	$ 4,920.98	$ 6,135.98	$ 6,135.98	$ 6,135.98	$ 6,135.98	$ 7,350.98	$ 7,350.98	$ 7,350.98	$ 7,350.98
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,500.00	$ 1,500.00	$ 1,500.00	$ 1,500.00
Smart Meter Charge @ $2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40
Default Service Support Charge @$ 1.053 /kW NSPL	$ 1,579.50	$ 1,579.50	$ 1,579.50	$ 1,579.50	$ 1,579.50	$ 2,106.00	$ 2,106.00	$ 2,106.00	$ 2,106.00	$ 2,632.50	$ 2,632.50	$ 2,632.50	$ 2,632.50	$ 3,159.00	$ 3,159.00	$ 3,159.00	$ 3,159.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 33.00	$ 99.00	$ 165.00	$ 240.90	$ 44.00	$ 132.00	$ 220.00	$ 321.20	$ 55.00	$ 165.00	$ 275.00	$ 401.50	$ 66.00	$ 198.00	$ 330.00	$ 481.80
Sub-Total	$ 2,331.90	$ 2,364.90	$ 2,430.90	$ 2,496.90	$ 2,572.80	$ 3,152.40	$ 3,240.40	$ 3,328.40	$ 3,429.60	$ 3,939.90	$ 4,049.90	$ 4,159.90	$ 4,286.40	$ 4,727.40	$ 4,859.40	$ 4,991.40	$ 5,143.20
PTC Charge																	
All kWh @ $ 0.05442 /kWh	$ -	$ 8,163.00	$ 24,489.00	$ 40,815.00	$ 59,589.90	$ 10,884.00	$ 32,652.00	$ 54,420.00	$ 79,453.20	$ 13,605.00	$ 40,815.00	$ 68,025.00	$ 99,316.50	$ 16,326.00	$ 48,978.00	$ 81,630.00	$ 119,179.80
Sub Total	$ 6,037.88	$ 14,230.88	$ 30,616.88	$ 47,002.88	$ 65,846.78	$ 18,953.38	$ 40,801.38	$ 62,649.38	$ 87,774.58	$ 23,675.88	$ 50,985.88	$ 78,295.88	$ 109,702.38	$ 28,398.38	$ 61,170.38	$ 93,942.38	$ 131,630.18
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 6,037.88**	**$ 14,230.88**	**$ 30,616.88**	**$ 47,002.88**	**$ 65,846.78**	**$ 18,953.38**	**$ 40,801.38**	**$ 62,649.38**	**$ 87,774.58**	**$ 23,675.88**	**$ 50,985.88**	**$ 78,295.88**	**$ 109,702.38**	**$ 28,398.38**	**$ 61,170.38**	**$ 93,942.38**	**$ 131,630.18**

UNBUNDLED RATES - PROPOSED

NUG Charge																	
All kWh @ -0.002 ¢/kWh	$ -	$ (3.00)	$ (9.00)	$ (15.00)	$ (21.90)	$ (4.00)	$ (12.00)	$ (20.00)	$ (29.20)	$ (5.00)	$ (15.00)	$ (25.00)	$ (36.50)	$ (6.00)	$ (18.00)	$ (30.00)	$ (43.80)
Distribution																	
Distribution Charge @ $93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87
All kW @ $3.63/kW	$ 5,445.00	$ 5,445.00	$ 5,445.00	$ 5,445.00	$ 5,445.00	$ 7,260.00	$ 7,260.00	$ 7,260.00	$ 7,260.00	$ 9,075.00	$ 9,075.00	$ 9,075.00	$ 9,075.00	$ 10,890.00	$ 10,890.00	$ 10,890.00	$ 10,890.00
All rkVA @$ 0.20 /rkVA	$ 180.00	$ 180.00	$ 180.00	$ 180.00	$ 180.00	$ 240.00	$ 240.00	$ 240.00	$ 240.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 360.00	$ 360.00	$ 360.00	$ 360.00
Sub-Total	$ 5,718.87	$ 5,718.87	$ 5,718.87	$ 5,718.87	$ 5,718.87	$ 7,593.87	$ 7,593.87	$ 7,593.87	$ 7,593.87	$ 9,468.87	$ 9,468.87	$ 9,468.87	$ 9,468.87	$ 11,343.87	$ 11,343.87	$ 11,343.87	$ 11,343.87
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,500.00	$ 1,500.00	$ 1,500.00	$ 1,500.00
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @$ 1.053 /kW NSPL	$ 1,579.50	$ 1,579.50	$ 1,579.50	$ 1,579.50	$ 1,579.50	$ 2,106.00	$ 2,106.00	$ 2,106.00	$ 2,106.00	$ 2,632.50	$ 2,632.50	$ 2,632.50	$ 2,632.50	$ 3,159.00	$ 3,159.00	$ 3,159.00	$ 3,159.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 33.00	$ 99.00	$ 165.00	$ 240.90	$ 44.00	$ 132.00	$ 220.00	$ 321.20	$ 55.00	$ 165.00	$ 275.00	$ 401.50	$ 66.00	$ 198.00	$ 330.00	$ 481.80
Sub-Total	$ 2,329.50	$ 2,362.50	$ 2,428.50	$ 2,494.50	$ 2,570.40	$ 3,150.00	$ 3,238.00	$ 3,326.00	$ 3,427.20	$ 3,937.50	$ 4,047.50	$ 4,157.50	$ 4,284.00	$ 4,725.00	$ 4,857.00	$ 4,989.00	$ 5,140.80
PTC Charge																	
All kWh @ $ 0.05442 /kWh	$ -	$ 8,163.00	$ 24,489.00	$ 40,815.00	$ 59,589.90	$ 10,884.00	$ 32,652.00	$ 54,420.00	$ 79,453.20	$ 13,605.00	$ 40,815.00	$ 68,025.00	$ 99,316.50	$ 16,326.00	$ 48,978.00	$ 81,630.00	$ 119,179.80
Sub Total	$ 8,048.37	$ 16,241.37	$ 32,627.37	$ 49,013.37	$ 67,857.27	$ 21,623.87	$ 43,471.87	$ 65,319.87	$ 90,445.07	$ 27,006.37	$ 54,316.37	$ 81,626.37	$ 113,032.87	$ 32,388.87	$ 65,160.87	$ 97,932.87	$ 135,620.67
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 8,048.37**	**$ 16,241.37**	**$ 32,627.37**	**$ 49,013.37**	**$ 67,857.27**	**$ 21,623.87**	**$ 43,471.87**	**$ 65,319.87**	**$ 90,445.07**	**$ 27,006.37**	**$ 54,316.37**	**$ 81,626.37**	**$ 113,032.87**	**$ 32,388.87**	**$ 65,160.87**	**$ 97,932.87**	**$ 135,620.67**
% Increase	**33.30%**	**14.13%**	**6.57%**	**4.28%**	**3.05%**	**14.09%**	**6.55%**	**4.26%**	**3.04%**	**14.07%**	**6.53%**	**4.25%**	**3.04%**	**14.05%**	**6.52%**	**4.25%**	**3.03%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS - LARGE - 8 HOUR ON PEAK TIME OF DAY vs RATE GS-LARGE
With Demands of 500 - 1,000 KW
At Average Levels of kWh Use

KW Demand																
Total kW	500	500	500	500	500	500	750	750	750	750	750	1,000	1,000	1,000	1,000	1,000
Hrs Use	0	200	300	400	500	730	200	300	400	500	730	200	300	400	500	730
REACTIVE DEMAND																
rkVA	300	300	300	300	300	300	450	450	450	450	450	600	600	600	600	600
ENERGY USAGE																
Monthly Energy Usage	0	100,000	150,000	200,000	250,000	365,000	150,000	225,000	300,000	375,000	547,500	200,000	300,000	400,000	500,000	730,000
Total Energy Usage	0	100,000	150,000	200,000	250,000	365,000	150,000	225,000	300,000	375,000	547,500	200,000	300,000	400,000	500,000	730,000
UNBUNDLED RATES - CURRENT																
NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (2.00)	$ (3.00)	$ (4.00)	$ (5.00)	$ (7.30)	$ (3.00)	$ (4.50)	$ (6.00)	$ (7.50)	$ (10.95)	$ (4.00)	$ (6.00)	$ (8.00)	$ (10.00)	$ (14.60)
Distribution																
Distribution Charge @ $60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98
All kW @ $2.43/kW	$ 1,215.00	$ 1,215.00	$ 1,215.00	$ 1,215.00	$ 1,215.00	$ 1,215.00	$ 1,822.50	$ 1,822.50	$ 1,822.50	$ 1,822.50	$ 1,822.50	$ 2,430.00	$ 2,430.00	$ 2,430.00	$ 2,430.00	$ 2,430.00
Sub-Total	$ 1,275.98	$ 1,275.98	$ 1,275.98	$ 1,275.98	$ 1,275.98	$ 1,275.98	$ 1,883.48	$ 1,883.48	$ 1,883.48	$ 1,883.48	$ 1,883.48	$ 2,490.98	$ 2,490.98	$ 2,490.98	$ 2,490.98	$ 2,490.98
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 375.00	$ 375.00	$ 375.00	$ 375.00	$ 375.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00
Smart Meter Charge @ $2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40
Default Service Support Charge @$ 1.053 /kW NSPL	$ 526.50	$ 526.50	$ 526.50	$ 526.50	$ 526.50	$ 526.50	$ 789.75	$ 789.75	$ 789.75	$ 789.75	$ 789.75	$ 1,053.00	$ 1,053.00	$ 1,053.00	$ 1,053.00	$ 1,053.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 22.00	$ 33.00	$ 44.00	$ 55.00	$ 80.30	$ 33.00	$ 49.50	$ 66.00	$ 82.50	$ 120.45	$ 44.00	$ 66.00	$ 88.00	$ 110.00	$ 160.60
Sub-Total	$ 778.90	$ 800.90	$ 811.90	$ 822.90	$ 833.90	$ 859.20	$ 1,200.15	$ 1,216.65	$ 1,233.15	$ 1,249.65	$ 1,287.60	$ 1,599.40	$ 1,621.40	$ 1,643.40	$ 1,665.40	$ 1,716.00
PTC Charge																
All kWh @ $ 0.05442 /kWh	$ -	$ 5,442.00	$ 8,163.00	$ 10,884.00	$ 13,605.00	$ 19,863.30	$ 8,163.00	$ 12,244.50	$ 16,326.00	$ 20,407.50	$ 29,794.95	$ 10,884.00	$ 16,326.00	$ 21,768.00	$ 27,210.00	$ 39,726.60
Sub Total	$ 2,054.88	$ 7,516.88	$ 10,247.88	$ 12,978.88	$ 15,709.88	$ 21,991.18	$ 11,243.63	$ 15,340.13	$ 19,436.63	$ 23,533.13	$ 32,955.08	$ 14,970.38	$ 20,432.38	$ 25,894.38	$ 31,356.38	$ 43,918.98
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 2,054.88**	**$ 7,516.88**	**$ 10,247.88**	**$ 12,978.88**	**$ 15,709.88**	**$ 21,991.18**	**$ 11,243.63**	**$ 15,340.13**	**$ 19,436.63**	**$ 23,533.13**	**$ 32,955.08**	**$ 14,970.38**	**$ 20,432.38**	**$ 25,894.38**	**$ 31,356.38**	**$ 43,918.98**
UNBUNDLED RATES - PROPOSED																
NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (2.00)	$ (3.00)	$ (4.00)	$ (5.00)	$ (7.30)	$ (3.00)	$ (4.50)	$ (6.00)	$ (7.50)	$ (10.95)	$ (4.00)	$ (6.00)	$ (8.00)	$ (10.00)	$ (14.60)
Distribution																
Distribution Charge @ $93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87
All kW @ $3.63/kW	$ 1,815.00	$ 1,815.00	$ 1,815.00	$ 1,815.00	$ 1,815.00	$ 1,815.00	$ 2,722.50	$ 2,722.50	$ 2,722.50	$ 2,722.50	$ 2,722.50	$ 3,630.00	$ 3,630.00	$ 3,630.00	$ 3,630.00	$ 3,630.00
All rkVA @$ 0.20 /rkVA	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 90.00	$ 90.00	$ 90.00	$ 90.00	$ 90.00	$ 120.00	$ 120.00	$ 120.00	$ 120.00	$ 120.00
Sub-Total	$ 1,968.87	$ 1,968.87	$ 1,968.87	$ 1,968.87	$ 1,968.87	$ 1,968.87	$ 2,906.37	$ 2,906.37	$ 2,906.37	$ 2,906.37	$ 2,906.37	$ 3,843.87	$ 3,843.87	$ 3,843.87	$ 3,843.87	$ 3,843.87
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 375.00	$ 375.00	$ 375.00	$ 375.00	$ 375.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @$ 1.053 /kW NSPL	$ 526.50	$ 526.50	$ 526.50	$ 526.50	$ 526.50	$ 526.50	$ 789.75	$ 789.75	$ 789.75	$ 789.75	$ 789.75	$ 1,053.00	$ 1,053.00	$ 1,053.00	$ 1,053.00	$ 1,053.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 22.00	$ 33.00	$ 44.00	$ 55.00	$ 80.30	$ 33.00	$ 49.50	$ 66.00	$ 82.50	$ 120.45	$ 44.00	$ 66.00	$ 88.00	$ 110.00	$ 160.60
Sub-Total	$ 776.50	$ 798.50	$ 809.50	$ 820.50	$ 831.50	$ 856.80	$ 1,197.75	$ 1,214.25	$ 1,230.75	$ 1,247.25	$ 1,285.20	$ 1,597.00	$ 1,619.00	$ 1,641.00	$ 1,663.00	$ 1,713.60
PTC Charge																
All kWh @ $ 0.05442 /kWh	$ -	$ 5,442.00	$ 8,163.00	$ 10,884.00	$ 13,605.00	$ 19,863.30	$ 8,163.00	$ 12,244.50	$ 16,326.00	$ 20,407.50	$ 29,794.95	$ 10,884.00	$ 16,326.00	$ 21,768.00	$ 27,210.00	$ 39,726.60
Sub Total	$ 2,745.37	$ 8,207.37	$ 10,938.37	$ 13,669.37	$ 16,400.37	$ 22,681.67	$ 12,264.12	$ 16,360.62	$ 20,457.12	$ 24,553.62	$ 33,975.57	$ 16,320.87	$ 21,782.87	$ 27,244.87	$ 32,706.87	$ 45,269.47
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 2,745.37**	**$ 8,207.37**	**$ 10,938.37**	**$ 13,669.37**	**$ 16,400.37**	**$ 22,681.67**	**$ 12,264.12**	**$ 16,360.62**	**$ 20,457.12**	**$ 24,553.62**	**$ 33,975.57**	**$ 16,320.87**	**$ 21,782.87**	**$ 27,244.87**	**$ 32,706.87**	**$ 45,269.47**
% Increase	**33.60%**	**9.19%**	**6.74%**	**5.32%**	**4.40%**	**3.14%**	**9.08%**	**6.65%**	**5.25%**	**4.34%**	**3.10%**	**9.02%**	**6.61%**	**5.22%**	**4.31%**	**3.07%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GS - LARGE - 8 HOUR ON PEAK TIME OF DAY vs RATE GS-LARGE
With Demands of 1,500 - 3,000 KW
At Average Levels of kWh Use

KW Demand																	
Total kW	1,500	1,500	1,500	1,500	1,500	2,000	2,000	2,000	2,000	2,500	2,500	2,500	2,500	3,000	3,000	3,000	3,000
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730
REACTIVE DEMAND																	
rkVA	900	900	900	900	900	1,200	1,200	1,200	1,200	1,500	1,500	1,500	1,500	1,800	1,800	1,800	1,800
ENERGY USAGE																	
Monthly Energy Usage	0	150,000	450,000	750,000	1,095,000	200,000	600,000	1,000,000	1,460,000	250,000	750,000	1,250,000	1,825,000	300,000	900,000	1,500,000	2,190,000
Total Energy Usage	0	150,000	450,000	750,000	1,095,000	200,000	600,000	1,000,000	1,460,000	250,000	750,000	1,250,000	1,825,000	300,000	900,000	1,500,000	2,190,000

UNBUNDLED RATES - CURRENT

NUG Charge																	
All kWh @ -0.002 ¢/kWh	$ -	$ (3.00)	$ (9.00)	$ (15.00)	$ (21.90)	$ (4.00)	$ (12.00)	$ (20.00)	$ (29.20)	$ (5.00)	$ (15.00)	$ (25.00)	$ (36.50)	$ (6.00)	$ (18.00)	$ (30.00)	$ (43.80)
Distribution																	
Distribution Charge @ $60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98	$ 60.98
All kW @ $2.43/kW	$ 3,645.00	$ 3,645.00	$ 3,645.00	$ 3,645.00	$ 3,645.00	$ 4,860.00	$ 4,860.00	$ 4,860.00	$ 4,860.00	$ 6,075.00	$ 6,075.00	$ 6,075.00	$ 6,075.00	$ 7,290.00	$ 7,290.00	$ 7,290.00	$ 7,290.00
Sub-Total	$ 3,705.98	$ 3,705.98	$ 3,705.98	$ 3,705.98	$ 3,705.98	$ 4,920.98	$ 4,920.98	$ 4,920.98	$ 4,920.98	$ 6,135.98	$ 6,135.98	$ 6,135.98	$ 6,135.98	$ 7,350.98	$ 7,350.98	$ 7,350.98	$ 7,350.98
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,500.00	$ 1,500.00	$ 1,500.00	$ 1,500.00
Smart Meter Charge @ $2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40	$ 2.40
Default Service Support Charge @$ 1.053 /kW NSPL	$ 1,579.50	$ 1,579.50	$ 1,579.50	$ 1,579.50	$ 1,579.50	$ 2,106.00	$ 2,106.00	$ 2,106.00	$ 2,106.00	$ 2,632.50	$ 2,632.50	$ 2,632.50	$ 2,632.50	$ 3,159.00	$ 3,159.00	$ 3,159.00	$ 3,159.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 33.00	$ 99.00	$ 165.00	$ 240.90	$ 44.00	$ 132.00	$ 220.00	$ 321.20	$ 55.00	$ 165.00	$ 275.00	$ 401.50	$ 66.00	$ 198.00	$ 330.00	$ 481.80
Sub-Total	$ 2,331.90	$ 2,364.90	$ 2,430.90	$ 2,496.90	$ 2,572.80	$ 3,152.40	$ 3,240.40	$ 3,328.40	$ 3,429.60	$ 3,939.90	$ 4,049.90	$ 4,159.90	$ 4,286.40	$ 4,727.40	$ 4,859.40	$ 4,991.40	$ 5,143.20
PTC Charge																	
All kWh @ $ 0.05442 /kWh	$ -	$ 8,163.00	$ 24,489.00	$ 40,815.00	$ 59,589.90	$ 10,884.00	$ 32,652.00	$ 54,420.00	$ 79,453.20	$ 13,605.00	$ 40,815.00	$ 68,025.00	$ 99,316.50	$ 16,326.00	$ 48,978.00	$ 81,630.00	$ 119,179.80
Sub Total	$ 6,037.88	$ 14,230.88	$ 30,616.88	$ 47,002.88	$ 65,846.78	$ 18,953.38	$ 40,801.38	$ 62,649.38	$ 87,774.58	$ 23,675.88	$ 50,985.88	$ 78,295.88	$ 109,702.38	$ 28,398.38	$ 61,170.38	$ 93,942.38	$ 131,630.18
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 6,037.88**	**$ 14,230.88**	**$ 30,616.88**	**$ 47,002.88**	**$ 65,846.78**	**$ 18,953.38**	**$ 40,801.38**	**$ 62,649.38**	**$ 87,774.58**	**$ 23,675.88**	**$ 50,985.88**	**$ 78,295.88**	**$ 109,702.38**	**$ 28,398.38**	**$ 61,170.38**	**$ 93,942.38**	**$ 131,630.18**

UNBUNDLED RATES - PROPOSED

NUG Charge																	
All kWh @ -0.002 ¢/kWh	$ -	$ (3.00)	$ (9.00)	$ (15.00)	$ (21.90)	$ (4.00)	$ (12.00)	$ (20.00)	$ (29.20)	$ (5.00)	$ (15.00)	$ (25.00)	$ (36.50)	$ (6.00)	$ (18.00)	$ (30.00)	$ (43.80)
Distribution																	
Distribution Charge @ $93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87	$ 93.87
All kW @ $3.63/kW	$ 5,445.00	$ 5,445.00	$ 5,445.00	$ 5,445.00	$ 5,445.00	$ 7,260.00	$ 7,260.00	$ 7,260.00	$ 7,260.00	$ 9,075.00	$ 9,075.00	$ 9,075.00	$ 9,075.00	$ 10,890.00	$ 10,890.00	$ 10,890.00	$ 10,890.00
All rkVA @$ 0.20 /rkVA	$ 180.00	$ 180.00	$ 180.00	$ 180.00	$ 180.00	$ 240.00	$ 240.00	$ 240.00	$ 240.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 360.00	$ 360.00	$ 360.00	$ 360.00
Sub-Total	$ 5,718.87	$ 5,718.87	$ 5,718.87	$ 5,718.87	$ 5,718.87	$ 7,593.87	$ 7,593.87	$ 7,593.87	$ 7,593.87	$ 9,468.87	$ 9,468.87	$ 9,468.87	$ 9,468.87	$ 11,343.87	$ 11,343.87	$ 11,343.87	$ 11,343.87
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,500.00	$ 1,500.00	$ 1,500.00	$ 1,500.00
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @$ 1.053 /kW NSPL	$ 1,579.50	$ 1,579.50	$ 1,579.50	$ 1,579.50	$ 1,579.50	$ 2,106.00	$ 2,106.00	$ 2,106.00	$ 2,106.00	$ 2,632.50	$ 2,632.50	$ 2,632.50	$ 2,632.50	$ 3,159.00	$ 3,159.00	$ 3,159.00	$ 3,159.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 33.00	$ 99.00	$ 165.00	$ 240.90	$ 44.00	$ 132.00	$ 220.00	$ 321.20	$ 55.00	$ 165.00	$ 275.00	$ 401.50	$ 66.00	$ 198.00	$ 330.00	$ 481.80
Sub-Total	$ 2,329.50	$ 2,362.50	$ 2,428.50	$ 2,494.50	$ 2,570.40	$ 3,150.00	$ 3,238.00	$ 3,326.00	$ 3,427.20	$ 3,937.50	$ 4,047.50	$ 4,157.50	$ 4,284.00	$ 4,725.00	$ 4,857.00	$ 4,989.00	$ 5,140.80
PTC Charge																	
All kWh @ $ 0.05442 /kWh	$ -	$ 8,163.00	$ 24,489.00	$ 40,815.00	$ 59,589.90	$ 10,884.00	$ 32,652.00	$ 54,420.00	$ 79,453.20	$ 13,605.00	$ 40,815.00	$ 68,025.00	$ 99,316.50	$ 16,326.00	$ 48,978.00	$ 81,630.00	$ 119,179.80
Sub Total	$ 8,048.37	$ 16,241.37	$ 32,627.37	$ 49,013.37	$ 67,857.27	$ 21,623.87	$ 43,471.87	$ 65,319.87	$ 90,445.07	$ 27,006.37	$ 54,316.37	$ 81,626.37	$ 113,032.87	$ 32,388.87	$ 65,160.87	$ 97,932.87	$ 135,620.67
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 8,048.37**	**$ 16,241.37**	**$ 32,627.37**	**$ 49,013.37**	**$ 67,857.27**	**$ 21,623.87**	**$ 43,471.87**	**$ 65,319.87**	**$ 90,445.07**	**$ 27,006.37**	**$ 54,316.37**	**$ 81,626.37**	**$ 113,032.87**	**$ 32,388.87**	**$ 65,160.87**	**$ 97,932.87**	**$ 135,620.67**
% Increase	**33.30%**	**14.13%**	**6.57%**	**4.28%**	**3.05%**	**14.09%**	**6.55%**	**4.26%**	**3.04%**	**14.07%**	**6.53%**	**4.25%**	**3.04%**	**14.05%**	**6.52%**	**4.25%**	**3.03%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GP - 12 HOUR ON PEAK TIME OF DAY vs RATE GP
With Demands of 25 - 150 KW
At Average Levels of kWh Use

KW Demand																		
Total kW	25	25	25	25	25	50	50	50	50	100	100	100	100	150	150	150	150	
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730	
REACTIVE DEMAND																		
rkVA	13	13	13	13	13	25	25	25	25	50	50	50	50	75	75	75	75	
ENERGY USAGE																		
Monthly Energy Usage	0	2,500	7,500	12,500	18,250	5,000	15,000	25,000	36,500	10,000	30,000	50,000	73,000	15,000	45,000	75,000	109,500	
Total Energy Usage	0	2,500	7,500	12,500	18,250	5,000	15,000	25,000	36,500	10,000	30,000	50,000	73,000	15,000	45,000	75,000	109,500	

UNBUNDLED RATES - CURRENT

NUG Charge																		
All kWh @ 0.037 ¢/kWh	$ -	$ 0.93	$ 2.78	$ 4.63	$ 6.75	$ 1.85	$ 5.55	$ 9.25	$ 13.51	$ 3.70	$ 11.10	$ 18.50	$ 27.01	$ 5.55	$ 16.65	$ 27.75	$ 40.52	
Distribution																		
Distribution Charge @ $235.28	$235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	
All kW @ $1.46/kW	$ 36.50	$ 36.50	$ 36.50	$ 36.50	$ 36.50	$ 73.00	$ 73.00	$ 73.00	$ 73.00	$ 146.00	$ 146.00	$ 146.00	$ 146.00	$ 219.00	$ 219.00	$ 219.00	$ 219.00	
All kWh @ 0.066 ¢/kWh	$ -	$ 1.65	$ 4.95	$ 8.25	$ 12.05	$ 3.30	$ 9.90	$ 16.50	$ 24.09	$ 6.60	$ 19.80	$ 33.00	$ 48.18	$ 9.90	$ 29.70	$ 49.50	$ 72.27	
Sub-Total	$ 271.78	$ 273.43	$ 276.73	$ 280.03	$ 283.83	$ 311.58	$ 318.18	$ 324.78	$ 332.37	$ 387.88	$ 401.08	$ 414.28	$ 429.46	$ 464.18	$ 483.98	$ 503.78	$ 526.55	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 12.50	$ 12.50	$ 12.50	$ 12.50	$ 12.50	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 75.00	$ 75.00	$ 75.00	$ 75.00	
Smart Meter Charge @ $2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	
Default Service Support Charge @$ 1.006 /kW NSPL	$ 25.15	$ 25.15	$ 25.15	$ 25.15	$ 25.15	$ 50.30	$ 50.30	$ 50.30	$ 50.30	$ 100.60	$ 100.60	$ 100.60	$ 100.60	$ 150.90	$ 150.90	$ 150.90	$ 150.90	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.55	$ 1.65	$ 2.75	$ 4.02	$ 1.10	$ 3.30	$ 5.50	$ 8.03	$ 2.20	$ 6.60	$ 11.00	$ 16.06	$ 3.30	$ 9.90	$ 16.50	$ 24.09	
Sub-Total	$ 39.97	$ 40.52	$ 41.62	$ 42.72	$ 43.99	$ 78.72	$ 80.92	$ 83.12	$ 85.65	$ 155.12	$ 159.52	$ 163.92	$ 168.98	$ 231.52	$ 238.12	$ 244.72	$ 252.31	
PTC Charge																		
All kWh @ $ 0.05262 /kWh	$ -	$ 131.55	$ 394.65	$ 657.75	$ 960.32	$ 263.10	$ 789.30	$ 1,315.50	$ 1,920.63	$ 526.20	$ 1,578.60	$ 2,631.00	$ 3,841.26	$ 789.30	$ 2,367.90	$ 3,946.50	$ 5,761.89	
Sub Total	$ 311.75	$ 446.43	$ 715.78	$ 985.13	$ 1,294.88	$ 655.25	$ 1,193.95	$ 1,732.65	$ 2,352.16	$ 1,072.90	$ 2,150.30	$ 3,227.70	$ 4,466.71	$ 1,490.55	$ 3,106.65	$ 4,722.75	$ 6,581.27	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 311.75**	**$ 446.43**	**$ 715.78**	**$ 985.13**	**$ 1,294.88**	**$ 655.25**	**$ 1,193.95**	**$ 1,732.65**	**$ 2,352.16**	**$ 1,072.90**	**$ 2,150.30**	**$ 3,227.70**	**$ 4,466.71**	**$ 1,490.55**	**$ 3,106.65**	**$ 4,722.75**	**$ 6,581.27**	

UNBUNDLED RATES - PROPOSED

NUG Charge																		
All kWh @ 0.037 ¢/kWh	$ -	$ 0.93	$ 2.78	$ 4.63	$ 6.75	$ 1.85	$ 5.55	$ 9.25	$ 13.51	$ 3.70	$ 11.10	$ 18.50	$ 27.01	$ 5.55	$ 16.65	$ 27.75	$ 40.52	
Distribution																		
Distribution Charge @ $308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	
All kW @ $3.35/kW	$ 83.75	$ 83.75	$ 83.75	$ 83.75	$ 83.75	$ 167.50	$ 167.50	$ 167.50	$ 167.50	$ 335.00	$ 335.00	$ 335.00	$ 335.00	$ 502.50	$ 502.50	$ 502.50	$ 502.50	
All rkVA @$ 0.20 /rkVA	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 10.00	$ 10.00	$ 10.00	$ 10.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	
Sub-Total	$ 394.44	$ 394.44	$ 394.44	$ 394.44	$ 394.44	$ 480.69	$ 480.69	$ 480.69	$ 480.69	$ 653.19	$ 653.19	$ 653.19	$ 653.19	$ 825.69	$ 825.69	$ 825.69	$ 825.69	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 12.50	$ 12.50	$ 12.50	$ 12.50	$ 12.50	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 75.00	$ 75.00	$ 75.00	$ 75.00	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @$ 1.006 /kW NSPL	$ 25.15	$ 25.15	$ 25.15	$ 25.15	$ 25.15	$ 50.30	$ 50.30	$ 50.30	$ 50.30	$ 100.60	$ 100.60	$ 100.60	$ 100.60	$ 150.90	$ 150.90	$ 150.90	$ 150.90	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.55	$ 1.65	$ 2.75	$ 4.02	$ 1.10	$ 3.30	$ 5.50	$ 8.03	$ 2.20	$ 6.60	$ 11.00	$ 16.06	$ 3.30	$ 9.90	$ 16.50	$ 24.09	
Sub-Total	$ 37.65	$ 38.20	$ 39.30	$ 40.40	$ 41.67	$ 76.40	$ 78.60	$ 80.80	$ 83.33	$ 152.80	$ 157.20	$ 161.60	$ 166.66	$ 229.20	$ 235.80	$ 242.40	$ 249.99	
PTC Charge																		
All kWh @ $ 0.05262 /kWh	$ -	$ 131.55	$ 394.65	$ 657.75	$ 960.32	$ 263.10	$ 789.30	$ 1,315.50	$ 1,920.63	$ 526.20	$ 1,578.60	$ 2,631.00	$ 3,841.26	$ 789.30	$ 2,367.90	$ 3,946.50	$ 5,761.89	
Sub Total	$ 432.09	$ 565.12	$ 831.17	$ 1,097.22	$ 1,403.17	$ 822.04	$ 1,354.14	$ 1,886.24	$ 2,498.16	$ 1,335.89	$ 2,400.09	$ 3,464.29	$ 4,688.12	$ 1,849.74	$ 3,446.04	$ 5,042.34	$ 6,878.09	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 432.09**	**$ 565.12**	**$ 831.17**	**$ 1,097.22**	**$ 1,403.17**	**$ 822.04**	**$ 1,354.14**	**$ 1,886.24**	**$ 2,498.16**	**$ 1,335.89**	**$ 2,400.09**	**$ 3,464.29**	**$ 4,688.12**	**$ 1,849.74**	**$ 3,446.04**	**$ 5,042.34**	**$ 6,878.09**	
% Increase	**38.60%**	**26.59%**	**16.12%**	**11.38%**	**8.36%**	**25.45%**	**13.42%**	**8.86%**	**6.21%**	**24.51%**	**11.62%**	**7.33%**	**4.96%**	**24.10%**	**10.92%**	**6.77%**	**4.51%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GP - 12 HOUR ON PEAK TIME OF DAY vs RATE GP
With Demands of 250 - 1,000 KW
At Average Levels of kWh Use

KW Demand																		
Total kW	250	250	250	250	250	500	500	500	500	750	750	750	750	1,000	1,000	1,000	1,000	
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730	
REACTIVE DEMAND																		
rkVA	125	125	125	125	125	250	250	250	250	375	375	375	375	500	500	500	500	
ENERGY USAGE																		
Monthly Energy Usage	0	25,000	75,000	125,000	182,500	50,000	150,000	250,000	365,000	75,000	225,000	375,000	547,500	100,000	300,000	500,000	730,000	
Total Energy Usage	0	25,000	75,000	125,000	182,500	50,000	150,000	250,000	365,000	75,000	225,000	375,000	547,500	100,000	300,000	500,000	730,000	
UNBUNDLED RATES - CURRENT																		
NUG Charge																		
All kWh @ 0.037 ¢/kWh	$ -	$ 9.25	$ 27.75	$ 46.25	$ 67.53	$ 18.50	$ 55.50	$ 92.50	$ 135.05	$ 27.75	$ 83.25	$ 138.75	$ 202.58	$ 37.00	$ 111.00	$ 185.00	$ 270.10	
Distribution																		
Distribution Charge @ $235.28	$235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	
All kW @ $1.46/kW	$ 365.00	$ 365.00	$ 365.00	$ 365.00	$ 365.00	$ 730.00	$ 730.00	$ 730.00	$ 730.00	$ 1,095.00	$ 1,095.00	$ 1,095.00	$ 1,095.00	$ 1,460.00	$ 1,460.00	$ 1,460.00	$ 1,460.00	
All kWh @ 0.066 ¢/kWh	$ -	$ 16.50	$ 49.50	$ 82.50	$ 120.45	$ 33.00	$ 99.00	$ 165.00	$ 240.90	$ 49.50	$ 148.50	$ 247.50	$ 361.35	$ 66.00	$ 198.00	$ 330.00	$ 481.80	
Sub-Total	$ 600.28	$ 616.78	$ 649.78	$ 682.78	$ 720.73	$ 998.28	$ 1,064.28	$ 1,130.28	$ 1,206.18	$ 1,379.78	$ 1,478.78	$ 1,577.78	$ 1,691.63	$ 1,761.28	$ 1,893.28	$ 2,025.28	$ 2,177.08	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 125.00	$ 125.00	$ 125.00	$ 125.00	$ 125.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 375.00	$ 375.00	$ 375.00	$ 375.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	
Smart Meter Charge @ $2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	
Default Service Support Charge @$ 1.006 /kW NSPL	$ 251.50	$ 251.50	$ 251.50	$ 251.50	$ 251.50	$ 503.00	$ 503.00	$ 503.00	$ 503.00	$ 754.50	$ 754.50	$ 754.50	$ 754.50	$ 1,006.00	$ 1,006.00	$ 1,006.00	$ 1,006.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 5.50	$ 16.50	$ 27.50	$ 40.15	$ 11.00	$ 33.00	$ 55.00	$ 80.30	$ 16.50	$ 49.50	$ 82.50	$ 120.45	$ 22.00	$ 66.00	$ 110.00	$ 160.60	
Sub-Total	$ 378.82	$ 384.32	$ 395.32	$ 406.32	$ 418.97	$ 766.32	$ 788.32	$ 810.32	$ 835.62	$ 1,148.32	$ 1,181.32	$ 1,214.32	$ 1,252.27	$ 1,530.32	$ 1,574.32	$ 1,618.32	$ 1,668.92	
PTC Charge																		
All kWh @ $ 0.05262 /kWh	$ -	$ 1,315.50	$ 3,946.50	$ 6,577.50	$ 9,603.15	$ 2,631.00	$ 7,893.00	$ 13,155.00	$ 19,206.30	$ 3,946.50	$ 11,839.50	$ 19,732.50	$ 28,809.45	$ 5,262.00	$ 15,786.00	$ 26,310.00	$ 38,412.60	
Sub Total	$ 979.10	$ 2,325.85	$ 5,019.35	$ 7,712.85	$ 10,810.38	$ 4,414.10	$ 9,801.10	$ 15,188.10	$ 21,383.15	$ 6,502.35	$ 14,582.85	$ 22,663.35	$ 31,955.93	$ 8,590.60	$ 19,364.60	$ 30,138.60	$ 42,528.70	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 979.10**	**$ 2,325.85**	**$ 5,019.35**	**$ 7,712.85**	**$ 10,810.38**	**$ 4,414.10**	**$ 9,801.10**	**$ 15,188.10**	**$ 21,383.15**	**$ 6,502.35**	**$ 14,582.85**	**$ 22,663.35**	**$ 31,955.93**	**$ 8,590.60**	**$ 19,364.60**	**$ 30,138.60**	**$ 42,528.70**	
UNBUNDLED RATES - PROPOSED																		
NUG Charge																		
All kWh @ 0.037 ¢/kWh	$ -	$ 9.25	$ 27.75	$ 46.25	$ 67.53	$ 18.50	$ 55.50	$ 92.50	$ 135.05	$ 27.75	$ 83.25	$ 138.75	$ 202.58	$ 37.00	$ 111.00	$ 185.00	$ 270.10	
Distribution																		
Distribution Charge @ $308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	
All kW @ $3.35/kW	$ 837.50	$ 837.50	$ 837.50	$ 837.50	$ 837.50	$ 1,675.00	$ 1,675.00	$ 1,675.00	$ 1,675.00	$ 2,512.50	$ 2,512.50	$ 2,512.50	$ 2,512.50	$ 3,350.00	$ 3,350.00	$ 3,350.00	$ 3,350.00	
All rkVA @$ 0.20 /rkVA	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 75.00	$ 75.00	$ 75.00	$ 75.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	
Sub-Total	$ 1,170.69	$ 1,170.69	$ 1,170.69	$ 1,170.69	$ 1,170.69	$ 2,033.19	$ 2,033.19	$ 2,033.19	$ 2,033.19	$ 2,895.69	$ 2,895.69	$ 2,895.69	$ 2,895.69	$ 3,758.19	$ 3,758.19	$ 3,758.19	$ 3,758.19	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 125.00	$ 125.00	$ 125.00	$ 125.00	$ 125.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 375.00	$ 375.00	$ 375.00	$ 375.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @$ 1.006 /kW NSPL	$ 251.50	$ 251.50	$ 251.50	$ 251.50	$ 251.50	$ 503.00	$ 503.00	$ 503.00	$ 503.00	$ 754.50	$ 754.50	$ 754.50	$ 754.50	$ 1,006.00	$ 1,006.00	$ 1,006.00	$ 1,006.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 5.50	$ 16.50	$ 27.50	$ 40.15	$ 11.00	$ 33.00	$ 55.00	$ 80.30	$ 16.50	$ 49.50	$ 82.50	$ 120.45	$ 22.00	$ 66.00	$ 110.00	$ 160.60	
Sub-Total	$ 376.50	$ 382.00	$ 393.00	$ 404.00	$ 416.65	$ 764.00	$ 786.00	$ 808.00	$ 833.30	$ 1,146.00	$ 1,179.00	$ 1,212.00	$ 1,249.95	$ 1,528.00	$ 1,572.00	$ 1,616.00	$ 1,666.60	
PTC Charge																		
All kWh @ $ 0.05262 /kWh	$ -	$ 1,315.50	$ 3,946.50	$ 6,577.50	$ 9,603.15	$ 2,631.00	$ 7,893.00	$ 13,155.00	$ 19,206.30	$ 3,946.50	$ 11,839.50	$ 19,732.50	$ 28,809.45	$ 5,262.00	$ 15,786.00	$ 26,310.00	$ 38,412.60	
Sub Total	$ 1,547.19	$ 2,877.44	$ 5,537.94	$ 8,198.44	$ 11,258.02	$ 5,446.69	$ 10,767.69	$ 16,088.69	$ 22,207.84	$ 8,015.94	$ 15,997.44	$ 23,978.94	$ 33,157.67	$ 10,585.19	$ 21,227.19	$ 31,869.19	$ 44,107.49	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 1,547.19**	**$ 2,877.44**	**$ 5,537.94**	**$ 8,198.44**	**$ 11,258.02**	**$ 5,446.69**	**$ 10,767.69**	**$ 16,088.69**	**$ 22,207.84**	**$ 8,015.94**	**$ 15,997.44**	**$ 23,978.94**	**$ 33,157.67**	**$ 10,585.19**	**$ 21,227.19**	**$ 31,869.19**	**$ 44,107.49**	
% Increase	**58.02%**	**23.72%**	**10.33%**	**6.30%**	**4.14%**	**23.39%**	**9.86%**	**5.93%**	**3.86%**	**23.28%**	**9.70%**	**5.80%**	**3.76%**	**23.22%**	**9.62%**	**5.74%**	**3.71%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GP - 12 HOUR ON PEAK TIME OF DAY vs RATE GP
With Demands of 1,500 - 3,000 KW
At Average Levels of kWh Use

KW Demand																		
Total kW	1,500	1,500	1,500	1,500	1,500	2,000	2,000	2,000	2,000	2,500	2,500	2,500	2,500	3,000	3,000	3,000	3,000	
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730	
REACTIVE DEMAND																		
rkVA	750	750	750	750	750	1,000	1,000	1,000	1,000	1,250	1,250	1,250	1,250	1,500	1,500	1,500	1,500	
ENERGY USAGE																		
Monthly Energy Usage	0	150,000	450,000	750,000	1,095,000	200,000	600,000	1,000,000	1,460,000	250,000	750,000	1,250,000	1,825,000	300,000	900,000	1,500,000	2,190,000	
Total Energy Usage	0	150,000	450,000	750,000	1,095,000	200,000	600,000	1,000,000	1,460,000	250,000	750,000	1,250,000	1,825,000	300,000	900,000	1,500,000	2,190,000	

UNBUNDLED RATES - CURRENT

NUG Charge																		
All kWh @ 0.037 ¢/kWh	$ -	$ 55.50	$ 166.50	$ 277.50	$ 405.15	$ 74.00	$ 222.00	$ 370.00	$ 540.20	$ 92.50	$ 277.50	$ 462.50	$ 675.25	$ 111.00	$ 333.00	$ 555.00	$ 810.30	
Distribution																		
Distribution Charge @ $235.28	$235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	
All kW @ $1.46/kW	$ 2,190.00	$ 2,190.00	$ 2,190.00	$ 2,190.00	$ 2,190.00	$ 2,920.00	$ 2,920.00	$ 2,920.00	$ 2,920.00	$ 3,650.00	$ 3,650.00	$ 3,650.00	$ 3,650.00	$ 4,380.00	$ 4,380.00	$ 4,380.00	$ 4,380.00	
All kWh @ 0.066 ¢/kWh	$ -	$ 99.00	$ 297.00	$ 495.00	$ 722.70	$ 132.00	$ 396.00	$ 660.00	$ 963.60	$ 165.00	$ 495.00	$ 825.00	$ 1,204.50	$ 198.00	$ 594.00	$ 990.00	$ 1,445.40	
Sub-Total	$ 2,425.28	$ 2,524.28	$ 2,722.28	$ 2,920.28	$ 3,147.98	$ 3,287.28	$ 3,551.28	$ 3,815.28	$ 4,118.88	$ 4,050.28	$ 4,380.28	$ 4,710.28	$ 5,089.78	$ 4,813.28	$ 5,209.28	$ 5,605.28	$ 6,060.68	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,500.00	$ 1,500.00	$ 1,500.00	$ 1,500.00	
Smart Meter Charge @ $2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	
Default Service Support Charge @$ 1.006 /kW NSPL	$ 1,509.00	$ 1,509.00	$ 1,509.00	$ 1,509.00	$ 1,509.00	$ 2,012.00	$ 2,012.00	$ 2,012.00	$ 2,012.00	$ 2,515.00	$ 2,515.00	$ 2,515.00	$ 2,515.00	$ 3,018.00	$ 3,018.00	$ 3,018.00	$ 3,018.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 33.00	$ 99.00	$ 165.00	$ 240.90	$ 44.00	$ 132.00	$ 220.00	$ 321.20	$ 55.00	$ 165.00	$ 275.00	$ 401.50	$ 66.00	$ 198.00	$ 330.00	$ 481.80	
Sub-Total	$ 2,261.32	$ 2,294.32	$ 2,360.32	$ 2,426.32	$ 2,502.22	$ 3,058.32	$ 3,146.32	$ 3,234.32	$ 3,335.52	$ 3,822.32	$ 3,932.32	$ 4,042.32	$ 4,168.82	$ 4,586.32	$ 4,718.32	$ 4,850.32	$ 5,002.12	
PTC Charge																		
All kWh @ $ 0.05262 /kWh	$ -	$ 7,893.00	$ 23,679.00	$ 39,465.00	$ 57,618.90	$ 10,524.00	$ 31,572.00	$ 52,620.00	$ 76,825.20	$ 13,155.00	$ 39,465.00	$ 65,775.00	$ 96,031.50	$ 15,786.00	$ 47,358.00	$ 78,930.00	$ 115,237.80	
Sub Total	$ 4,686.60	$ 12,767.10	$ 28,928.10	$ 45,089.10	$ 63,674.25	$ 16,943.60	$ 38,491.60	$ 60,039.60	$ 84,819.80	$ 21,120.10	$ 48,055.10	$ 74,990.10	$ 105,965.35	$ 25,296.60	$ 57,618.60	$ 89,940.60	$ 127,110.90	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 4,686.60**	**$ 12,767.10**	**$ 28,928.10**	**$ 45,089.10**	**$ 63,674.25**	**$ 16,943.60**	**$ 38,491.60**	**$ 60,039.60**	**$ 84,819.80**	**$ 21,120.10**	**$ 48,055.10**	**$ 74,990.10**	**$ 105,965.35**	**$ 25,296.60**	**$ 57,618.60**	**$ 89,940.60**	**$ 127,110.90**	

UNBUNDLED RATES - PROPOSED

NUG Charge																		
All kWh @ 0.037 ¢/kWh	$ -	$ 55.50	$ 166.50	$ 277.50	$ 405.15	$ 74.00	$ 222.00	$ 370.00	$ 540.20	$ 92.50	$ 277.50	$ 462.50	$ 675.25	$ 111.00	$ 333.00	$ 555.00	$ 810.30	
Distribution																		
Distribution Charge @ $308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	
All kW @ $3.35/kW	$ 5,025.00	$ 5,025.00	$ 5,025.00	$ 5,025.00	$ 5,025.00	$ 6,700.00	$ 6,700.00	$ 6,700.00	$ 6,700.00	$ 8,375.00	$ 8,375.00	$ 8,375.00	$ 8,375.00	$ 10,050.00	$ 10,050.00	$ 10,050.00	$ 10,050.00	
All rkVA @$ 0.20 /rkVA	$ 150.00	$ 150.00	$ 150.00	$ 150.00	$ 150.00	$ 200.00	$ 200.00	$ 200.00	$ 200.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	
Sub-Total	$ 5,483.19	$ 5,483.19	$ 5,483.19	$ 5,483.19	$ 5,483.19	$ 7,208.19	$ 7,208.19	$ 7,208.19	$ 7,208.19	$ 8,933.19	$ 8,933.19	$ 8,933.19	$ 8,933.19	$ 10,658.19	$ 10,658.19	$ 10,658.19	$ 10,658.19	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,500.00	$ 1,500.00	$ 1,500.00	$ 1,500.00	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @$ 1.006 /kW NSPL	$ 1,509.00	$ 1,509.00	$ 1,509.00	$ 1,509.00	$ 1,509.00	$ 2,012.00	$ 2,012.00	$ 2,012.00	$ 2,012.00	$ 2,515.00	$ 2,515.00	$ 2,515.00	$ 2,515.00	$ 3,018.00	$ 3,018.00	$ 3,018.00	$ 3,018.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 33.00	$ 99.00	$ 165.00	$ 240.90	$ 44.00	$ 132.00	$ 220.00	$ 321.20	$ 55.00	$ 165.00	$ 275.00	$ 401.50	$ 66.00	$ 198.00	$ 330.00	$ 481.80	
Sub-Total	$ 2,259.00	$ 2,292.00	$ 2,358.00	$ 2,424.00	$ 2,499.90	$ 3,056.00	$ 3,144.00	$ 3,232.00	$ 3,333.20	$ 3,820.00	$ 3,930.00	$ 4,040.00	$ 4,166.50	$ 4,584.00	$ 4,716.00	$ 4,848.00	$ 4,999.80	
PTC Charge																		
All kWh @ $ 0.05262 /kWh	$ -	$ 7,893.00	$ 23,679.00	$ 39,465.00	$ 57,618.90	$ 10,524.00	$ 31,572.00	$ 52,620.00	$ 76,825.20	$ 13,155.00	$ 39,465.00	$ 65,775.00	$ 96,031.50	$ 15,786.00	$ 47,358.00	$ 78,930.00	$ 115,237.80	
Sub Total	$ 7,742.19	$ 15,723.69	$ 31,686.69	$ 47,649.69	$ 66,007.14	$ 20,862.19	$ 42,146.19	$ 63,430.19	$ 87,906.79	$ 26,000.69	$ 52,605.69	$ 79,210.69	$ 109,806.44	$ 31,139.19	$ 63,065.19	$ 94,991.19	$ 131,706.09	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 7,742.19**	**$ 15,723.69**	**$ 31,686.69**	**$ 47,649.69**	**$ 66,007.14**	**$ 20,862.19**	**$ 42,146.19**	**$ 63,430.19**	**$ 87,906.79**	**$ 26,000.69**	**$ 52,605.69**	**$ 79,210.69**	**$ 109,806.44**	**$ 31,139.19**	**$ 63,065.19**	**$ 94,991.19**	**$ 131,706.09**	
% Increase	**65.20%**	**23.16%**	**9.54%**	**5.68%**	**3.66%**	**23.13%**	**9.49%**	**5.65%**	**3.64%**	**23.11%**	**9.47%**	**5.63%**	**3.62%**	**23.10%**	**9.45%**	**5.62%**	**3.62%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GP - 8 HOUR ON PEAK TIME OF DAY vs RATE GP
With Demands of 25 - 150 KW
At Average Levels of kWh Use

KW Demand																		
Total kW	25	25	25	25	25	50	50	50	50	100	100	100	100	150	150	150	150	
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730	
REACTIVE DEMAND																		
rkVA	13	13	13	13	13	25	25	25	25	50	50	50	50	75	75	75	75	
ENERGY USAGE																		
Monthly Energy Usage	0	2,500	7,500	12,500	18,250	5,000	15,000	25,000	36,500	10,000	30,000	50,000	73,000	15,000	45,000	75,000	109,500	
Total Energy Usage	0	2,500	7,500	12,500	18,250	5,000	15,000	25,000	36,500	10,000	30,000	50,000	73,000	15,000	45,000	75,000	109,500	

UNBUNDLED RATES - CURRENT

NUG Charge																		
All kWh @ 0.037 ¢/kWh	$ -	$ 0.93	$ 2.78	$ 4.63	$ 6.75	$ 1.85	$ 5.55	$ 9.25	$ 13.51	$ 3.70	$ 11.10	$ 18.50	$ 27.01	$ 5.55	$ 16.65	$ 27.75	$ 40.52	
Distribution																		
Distribution Charge @ $235.28	$235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	
All kW @ $1.46/kW	$ 36.50	$ 36.50	$ 36.50	$ 36.50	$ 36.50	$ 73.00	$ 73.00	$ 73.00	$ 73.00	$ 146.00	$ 146.00	$ 146.00	$ 146.00	$ 219.00	$ 219.00	$ 219.00	$ 219.00	
All kWh @ 0.066 ¢/kWh	$ -	$ 1.65	$ 4.95	$ 8.25	$ 12.05	$ 3.30	$ 9.90	$ 16.50	$ 24.09	$ 6.60	$ 19.80	$ 33.00	$ 48.18	$ 9.90	$ 29.70	$ 49.50	$ 72.27	
Sub-Total	$ 271.78	$ 273.43	$ 276.73	$ 280.03	$ 283.83	$ 311.58	$ 318.18	$ 324.78	$ 332.37	$ 387.88	$ 401.08	$ 414.28	$ 429.46	$ 464.18	$ 483.98	$ 503.78	$ 526.55	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 12.50	$ 12.50	$ 12.50	$ 12.50	$ 12.50	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 75.00	$ 75.00	$ 75.00	$ 75.00	
Smart Meter Charge @ $2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	
Default Service Support Charge @$ 1.006 /kW NSPL	$ 25.15	$ 25.15	$ 25.15	$ 25.15	$ 25.15	$ 50.30	$ 50.30	$ 50.30	$ 50.30	$ 100.60	$ 100.60	$ 100.60	$ 100.60	$ 150.90	$ 150.90	$ 150.90	$ 150.90	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.55	$ 1.65	$ 2.75	$ 4.02	$ 1.10	$ 3.30	$ 5.50	$ 8.03	$ 2.20	$ 6.60	$ 11.00	$ 16.06	$ 3.30	$ 9.90	$ 16.50	$ 24.09	
Sub-Total	$ 39.97	$ 40.52	$ 41.62	$ 42.72	$ 43.99	$ 78.72	$ 80.92	$ 83.12	$ 85.65	$ 155.12	$ 159.52	$ 163.92	$ 168.98	$ 231.52	$ 238.12	$ 244.72	$ 252.31	
PTC Charge																		
All kWh @ $ 0.05262 /kWh	$ -	$ 131.55	$ 394.65	$ 657.75	$ 960.32	$ 263.10	$ 789.30	$ 1,315.50	$ 1,920.63	$ 526.20	$ 1,578.60	$ 2,631.00	$ 3,841.26	$ 789.30	$ 2,367.90	$ 3,946.50	$ 5,761.89	
Sub Total	$ 311.75	$ 446.43	$ 715.78	$ 985.13	$ 1,294.88	$ 655.25	$ 1,193.95	$ 1,732.65	$ 2,352.16	$ 1,072.90	$ 2,150.30	$ 3,227.70	$ 4,466.71	$ 1,490.55	$ 3,106.65	$ 4,722.75	$ 6,581.27	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 311.75**	**$ 446.43**	**$ 715.78**	**$ 985.13**	**$ 1,294.88**	**$ 655.25**	**$ 1,193.95**	**$ 1,732.65**	**$ 2,352.16**	**$ 1,072.90**	**$ 2,150.30**	**$ 3,227.70**	**$ 4,466.71**	**$ 1,490.55**	**$ 3,106.65**	**$ 4,722.75**	**$ 6,581.27**	

UNBUNDLED RATES - PROPOSED

NUG Charge																		
All kWh @ 0.037 ¢/kWh	$ -	$ 0.93	$ 2.78	$ 4.63	$ 6.75	$ 1.85	$ 5.55	$ 9.25	$ 13.51	$ 3.70	$ 11.10	$ 18.50	$ 27.01	$ 5.55	$ 16.65	$ 27.75	$ 40.52	
Distribution																		
Distribution Charge @ $308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	
All kW @ $3.35/kW	$ 83.75	$ 83.75	$ 83.75	$ 83.75	$ 83.75	$ 167.50	$ 167.50	$ 167.50	$ 167.50	$ 335.00	$ 335.00	$ 335.00	$ 335.00	$ 502.50	$ 502.50	$ 502.50	$ 502.50	
All rkVA @$ 0.20 /rkVA	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 10.00	$ 10.00	$ 10.00	$ 10.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	
Sub-Total	$ 394.44	$ 394.44	$ 394.44	$ 394.44	$ 394.44	$ 480.69	$ 480.69	$ 480.69	$ 480.69	$ 653.19	$ 653.19	$ 653.19	$ 653.19	$ 825.69	$ 825.69	$ 825.69	$ 825.69	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 12.50	$ 12.50	$ 12.50	$ 12.50	$ 12.50	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 75.00	$ 75.00	$ 75.00	$ 75.00	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @$ 1.006 /kW NSPL	$ 25.15	$ 25.15	$ 25.15	$ 25.15	$ 25.15	$ 50.30	$ 50.30	$ 50.30	$ 50.30	$ 100.60	$ 100.60	$ 100.60	$ 100.60	$ 150.90	$ 150.90	$ 150.90	$ 150.90	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.55	$ 1.65	$ 2.75	$ 4.02	$ 1.10	$ 3.30	$ 5.50	$ 8.03	$ 2.20	$ 6.60	$ 11.00	$ 16.06	$ 3.30	$ 9.90	$ 16.50	$ 24.09	
Sub-Total	$ 37.65	$ 38.20	$ 39.30	$ 40.40	$ 41.67	$ 76.40	$ 78.60	$ 80.80	$ 83.33	$ 152.80	$ 157.20	$ 161.60	$ 166.66	$ 229.20	$ 235.80	$ 242.40	$ 249.99	
PTC Charge																		
All kWh @ $ 0.05262 /kWh	$ -	$ 131.55	$ 394.65	$ 657.75	$ 960.32	$ 263.10	$ 789.30	$ 1,315.50	$ 1,920.63	$ 526.20	$ 1,578.60	$ 2,631.00	$ 3,841.26	$ 789.30	$ 2,367.90	$ 3,946.50	$ 5,761.89	
Sub Total	$ 432.09	$ 565.12	$ 831.17	$ 1,097.22	$ 1,403.17	$ 822.04	$ 1,354.14	$ 1,886.24	$ 2,498.16	$ 1,335.89	$ 2,400.09	$ 3,464.29	$ 4,688.12	$ 1,849.74	$ 3,446.04	$ 5,042.34	$ 6,878.09	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 432.09**	**$ 565.12**	**$ 831.17**	**$ 1,097.22**	**$ 1,403.17**	**$ 822.04**	**$ 1,354.14**	**$ 1,886.24**	**$ 2,498.16**	**$ 1,335.89**	**$ 2,400.09**	**$ 3,464.29**	**$ 4,688.12**	**$ 1,849.74**	**$ 3,446.04**	**$ 5,042.34**	**$ 6,878.09**	
% Increase	**38.60%**	**26.59%**	**16.12%**	**11.38%**	**8.36%**	**25.45%**	**13.42%**	**8.86%**	**6.21%**	**24.51%**	**11.62%**	**7.33%**	**4.96%**	**24.10%**	**10.92%**	**6.77%**	**4.51%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GP - 8 HOUR ON PEAK TIME OF DAY vs RATE GP
With Demands of 250 - 1,000 KW
At Average Levels of kWh Use

KW Demand																		
Total kW	250	250	250	250	250	500	500	500	500	750	750	750	750	1,000	1,000	1,000	1,000	
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730	
REACTIVE DEMAND																		
rkVA	125	125	125	125	125	250	250	250	250	375	375	375	375	500	500	500	500	
ENERGY USAGE																		
Monthly Energy Usage	0	25,000	75,000	125,000	182,500	50,000	150,000	250,000	365,000	75,000	225,000	375,000	547,500	100,000	300,000	500,000	730,000	
Total Energy Usage	0	25,000	75,000	125,000	182,500	50,000	150,000	250,000	365,000	75,000	225,000	375,000	547,500	100,000	300,000	500,000	730,000	

UNBUNDLED RATES - CURRENT

NUG Charge																		
All kWh @ 0.037 ¢/kWh	$ -	$ 9.25	$ 27.75	$ 46.25	$ 67.53	$ 18.50	$ 55.50	$ 92.50	$ 135.05	$ 27.75	$ 83.25	$ 138.75	$ 202.58	$ 37.00	$ 111.00	$ 185.00	$ 270.10	
Distribution																		
Distribution Charge @ $235.28	$235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	
All kW @ $1.46/kW	$ 365.00	$ 365.00	$ 365.00	$ 365.00	$ 365.00	$ 730.00	$ 730.00	$ 730.00	$ 730.00	$ 1,095.00	$ 1,095.00	$ 1,095.00	$ 1,095.00	$ 1,460.00	$ 1,460.00	$ 1,460.00	$ 1,460.00	
All kWh @ 0.066 ¢/kWh	$ -	$ 16.50	$ 49.50	$ 82.50	$ 120.45	$ 33.00	$ 99.00	$ 165.00	$ 240.90	$ 49.50	$ 148.50	$ 247.50	$ 361.35	$ 66.00	$ 198.00	$ 330.00	$ 481.80	
Sub-Total	$ 600.28	$ 616.78	$ 649.78	$ 682.78	$ 720.73	$ 998.28	$ 1,064.28	$ 1,130.28	$ 1,206.18	$ 1,379.78	$ 1,478.78	$ 1,577.78	$ 1,691.63	$ 1,761.28	$ 1,893.28	$ 2,025.28	$ 2,177.08	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 125.00	$ 125.00	$ 125.00	$ 125.00	$ 125.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 375.00	$ 375.00	$ 375.00	$ 375.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	
Smart Meter Charge @ $2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	
Default Service Support Charge @$ 1.006 /kW NSPL	$ 251.50	$ 251.50	$ 251.50	$ 251.50	$ 251.50	$ 503.00	$ 503.00	$ 503.00	$ 503.00	$ 754.50	$ 754.50	$ 754.50	$ 754.50	$ 1,006.00	$ 1,006.00	$ 1,006.00	$ 1,006.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 5.50	$ 16.50	$ 27.50	$ 40.15	$ 11.00	$ 33.00	$ 55.00	$ 80.30	$ 16.50	$ 49.50	$ 82.50	$ 120.45	$ 22.00	$ 66.00	$ 110.00	$ 160.60	
Sub-Total	$ 378.82	$ 384.32	$ 395.32	$ 406.32	$ 418.97	$ 766.32	$ 788.32	$ 810.32	$ 835.62	$ 1,148.32	$ 1,181.32	$ 1,214.32	$ 1,252.27	$ 1,530.32	$ 1,574.32	$ 1,618.32	$ 1,668.92	
PTC Charge																		
All kWh @ $ 0.05262 /kWh	$ -	$ 1,315.50	$ 3,946.50	$ 6,577.50	$ 9,603.15	$ 2,631.00	$ 7,893.00	$ 13,155.00	$ 19,206.30	$ 3,946.50	$ 11,839.50	$ 19,732.50	$ 28,809.45	$ 5,262.00	$ 15,786.00	$ 26,310.00	$ 38,412.60	
Sub Total	$ 979.10	$ 2,325.85	$ 5,019.35	$ 7,712.85	$ 10,810.38	$ 4,414.10	$ 9,801.10	$ 15,188.10	$ 21,383.15	$ 6,502.35	$ 14,582.85	$ 22,663.35	$ 31,955.93	$ 8,590.60	$ 19,364.60	$ 30,138.60	$ 42,528.70	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 979.10**	**$ 2,325.85**	**$ 5,019.35**	**$ 7,712.85**	**$ 10,810.38**	**$ 4,414.10**	**$ 9,801.10**	**$ 15,188.10**	**$ 21,383.15**	**$ 6,502.35**	**$ 14,582.85**	**$ 22,663.35**	**$ 31,955.93**	**$ 8,590.60**	**$ 19,364.60**	**$ 30,138.60**	**$ 42,528.70**	

UNBUNDLED RATES - PROPOSED

NUG Charge																		
All kWh @ 0.037 ¢/kWh	$ -	$ 9.25	$ 27.75	$ 46.25	$ 67.53	$ 18.50	$ 55.50	$ 92.50	$ 135.05	$ 27.75	$ 83.25	$ 138.75	$ 202.58	$ 37.00	$ 111.00	$ 185.00	$ 270.10	
Distribution																		
Distribution Charge @ $308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	
All kW @ $3.35/kW	$ 837.50	$ 837.50	$ 837.50	$ 837.50	$ 837.50	$ 1,675.00	$ 1,675.00	$ 1,675.00	$ 1,675.00	$ 2,512.50	$ 2,512.50	$ 2,512.50	$ 2,512.50	$ 3,350.00	$ 3,350.00	$ 3,350.00	$ 3,350.00	
All rkVA @$ 0.20 /rkVA	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 75.00	$ 75.00	$ 75.00	$ 75.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	
Sub-Total	$ 1,170.69	$ 1,170.69	$ 1,170.69	$ 1,170.69	$ 1,170.69	$ 2,033.19	$ 2,033.19	$ 2,033.19	$ 2,033.19	$ 2,895.69	$ 2,895.69	$ 2,895.69	$ 2,895.69	$ 3,758.19	$ 3,758.19	$ 3,758.19	$ 3,758.19	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 125.00	$ 125.00	$ 125.00	$ 125.00	$ 125.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 375.00	$ 375.00	$ 375.00	$ 375.00	$ 500.00	$ 500.00	$ 500.00	$ 500.00	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @$ 1.006 /kW NSPL	$ 251.50	$ 251.50	$ 251.50	$ 251.50	$ 251.50	$ 503.00	$ 503.00	$ 503.00	$ 503.00	$ 754.50	$ 754.50	$ 754.50	$ 754.50	$ 1,006.00	$ 1,006.00	$ 1,006.00	$ 1,006.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 5.50	$ 16.50	$ 27.50	$ 40.15	$ 11.00	$ 33.00	$ 55.00	$ 80.30	$ 16.50	$ 49.50	$ 82.50	$ 120.45	$ 22.00	$ 66.00	$ 110.00	$ 160.60	
Sub-Total	$ 376.50	$ 382.00	$ 393.00	$ 404.00	$ 416.65	$ 764.00	$ 786.00	$ 808.00	$ 833.30	$ 1,146.00	$ 1,179.00	$ 1,212.00	$ 1,249.95	$ 1,528.00	$ 1,572.00	$ 1,616.00	$ 1,666.60	
PTC Charge																		
All kWh @ $ 0.05262 /kWh	$ -	$ 1,315.50	$ 3,946.50	$ 6,577.50	$ 9,603.15	$ 2,631.00	$ 7,893.00	$ 13,155.00	$ 19,206.30	$ 3,946.50	$ 11,839.50	$ 19,732.50	$ 28,809.45	$ 5,262.00	$ 15,786.00	$ 26,310.00	$ 38,412.60	
Sub Total	$ 1,547.19	$ 2,877.44	$ 5,537.94	$ 8,198.44	$ 11,258.02	$ 5,446.69	$ 10,767.69	$ 16,088.69	$ 22,207.84	$ 8,015.94	$ 15,997.44	$ 23,978.94	$ 33,157.67	$ 10,585.19	$ 21,227.19	$ 31,869.19	$ 44,107.49	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 1,547.19**	**$ 2,877.44**	**$ 5,537.94**	**$ 8,198.44**	**$ 11,258.02**	**$ 5,446.69**	**$ 10,767.69**	**$ 16,088.69**	**$ 22,207.84**	**$ 8,015.94**	**$ 15,997.44**	**$ 23,978.94**	**$ 33,157.67**	**$ 10,585.19**	**$ 21,227.19**	**$ 31,869.19**	**$ 44,107.49**	
% Increase	**58.02%**	**23.72%**	**10.33%**	**6.30%**	**4.14%**	**23.39%**	**9.86%**	**5.93%**	**3.86%**	**23.28%**	**9.70%**	**5.80%**	**3.76%**	**23.22%**	**9.62%**	**5.74%**	**3.71%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE GP - 8 HOUR ON PEAK TIME OF DAY vs RATE GP
With Demands of 1,500 - 3,000 KW
At Average Levels of kWh Use

KW Demand																		
Total kW	1,500	1,500	1,500	1,500	1,500	2,000	2,000	2,000	2,000	2,500	2,500	2,500	2,500	3,000	3,000	3,000	3,000	
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730	
REACTIVE DEMAND																		
rkVA	750	750	750	750	750	1,000	1,000	1,000	1,000	1,250	1,250	1,250	1,250	1,500	1,500	1,500	1,500	
ENERGY USAGE																		
Monthly Energy Usage	0	150,000	450,000	750,000	1,095,000	200,000	600,000	1,000,000	1,460,000	250,000	750,000	1,250,000	1,825,000	300,000	900,000	1,500,000	2,190,000	
Total Energy Usage	0	150,000	450,000	750,000	1,095,000	200,000	600,000	1,000,000	1,460,000	250,000	750,000	1,250,000	1,825,000	300,000	900,000	1,500,000	2,190,000	

UNBUNDLED RATES - CURRENT

NUG Charge																		
All kWh @ 0.037 ¢/kWh	$ -	$ 55.50	$ 166.50	$ 277.50	$ 405.15	$ 74.00	$ 222.00	$ 370.00	$ 540.20	$ 92.50	$ 277.50	$ 462.50	$ 675.25	$ 111.00	$ 333.00	$ 555.00	$ 810.30	
Distribution																		
Distribution Charge @ $235.28	$235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	$ 235.28	
All kW @ $1.46/kW	$ 2,190.00	$ 2,190.00	$ 2,190.00	$ 2,190.00	$ 2,190.00	$ 2,920.00	$ 2,920.00	$ 2,920.00	$ 2,920.00	$ 3,650.00	$ 3,650.00	$ 3,650.00	$ 3,650.00	$ 4,380.00	$ 4,380.00	$ 4,380.00	$ 4,380.00	
All kWh @ 0.066 ¢/kWh	$ -	$ 99.00	$ 297.00	$ 495.00	$ 722.70	$ 132.00	$ 396.00	$ 660.00	$ 963.60	$ 165.00	$ 495.00	$ 825.00	$ 1,204.50	$ 198.00	$ 594.00	$ 990.00	$ 1,445.40	
Sub-Total	$ 2,425.28	$ 2,524.28	$ 2,722.28	$ 2,920.28	$ 3,147.98	$ 3,287.28	$ 3,551.28	$ 3,815.28	$ 4,118.88	$ 4,050.28	$ 4,380.28	$ 4,710.28	$ 5,089.78	$ 4,813.28	$ 5,209.28	$ 5,605.28	$ 6,060.68	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,500.00	$ 1,500.00	$ 1,500.00	$ 1,500.00	
Smart Meter Charge @ $2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	$ 2.32	
Default Service Support Charge @$ 1.006 /kW NSPL	$ 1,509.00	$ 1,509.00	$ 1,509.00	$ 1,509.00	$ 1,509.00	$ 2,012.00	$ 2,012.00	$ 2,012.00	$ 2,012.00	$ 2,515.00	$ 2,515.00	$ 2,515.00	$ 2,515.00	$ 3,018.00	$ 3,018.00	$ 3,018.00	$ 3,018.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 33.00	$ 99.00	$ 165.00	$ 240.90	$ 44.00	$ 132.00	$ 220.00	$ 321.20	$ 55.00	$ 165.00	$ 275.00	$ 401.50	$ 66.00	$ 198.00	$ 330.00	$ 481.80	
Sub-Total	$ 2,261.32	$ 2,294.32	$ 2,360.32	$ 2,426.32	$ 2,502.22	$ 3,058.32	$ 3,146.32	$ 3,234.32	$ 3,335.52	$ 3,822.32	$ 3,932.32	$ 4,042.32	$ 4,168.82	$ 4,586.32	$ 4,718.32	$ 4,850.32	$ 5,002.12	
PTC Charge																		
All kWh @ $ 0.05262 /kWh	$ -	$ 7,893.00	$ 23,679.00	$ 39,465.00	$ 57,618.90	$ 10,524.00	$ 31,572.00	$ 52,620.00	$ 76,825.20	$ 13,155.00	$ 39,465.00	$ 65,775.00	$ 96,031.50	$ 15,786.00	$ 47,358.00	$ 78,930.00	$ 115,237.80	
Sub Total	$ 4,686.60	$ 12,767.10	$ 28,928.10	$ 45,089.10	$ 63,674.25	$ 16,943.60	$ 38,491.60	$ 60,039.60	$ 84,819.80	$ 21,120.10	$ 48,055.10	$ 74,990.10	$ 105,965.35	$ 25,296.60	$ 57,618.60	$ 89,940.60	$ 127,110.90	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 4,686.60**	**$ 12,767.10**	**$ 28,928.10**	**$ 45,089.10**	**$ 63,674.25**	**$ 16,943.60**	**$ 38,491.60**	**$ 60,039.60**	**$ 84,819.80**	**$ 21,120.10**	**$ 48,055.10**	**$ 74,990.10**	**$ 105,965.35**	**$ 25,296.60**	**$ 57,618.60**	**$ 89,940.60**	**$ 127,110.90**	

UNBUNDLED RATES - PROPOSED

NUG Charge																		
All kWh @ 0.037 ¢/kWh	$ -	$ 55.50	$ 166.50	$ 277.50	$ 405.15	$ 74.00	$ 222.00	$ 370.00	$ 540.20	$ 92.50	$ 277.50	$ 462.50	$ 675.25	$ 111.00	$ 333.00	$ 555.00	$ 810.30	
Distribution																		
Distribution Charge @ $308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	$ 308.19	
All kW @ $3.35/kW	$ 5,025.00	$ 5,025.00	$ 5,025.00	$ 5,025.00	$ 5,025.00	$ 6,700.00	$ 6,700.00	$ 6,700.00	$ 6,700.00	$ 8,375.00	$ 8,375.00	$ 8,375.00	$ 8,375.00	$ 10,050.00	$ 10,050.00	$ 10,050.00	$ 10,050.00	
All rkVA @$ 0.20 /rkVA	$ 150.00	$ 150.00	$ 150.00	$ 150.00	$ 150.00	$ 200.00	$ 200.00	$ 200.00	$ 200.00	$ 250.00	$ 250.00	$ 250.00	$ 250.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	
Sub-Total	$ 5,483.19	$ 5,483.19	$ 5,483.19	$ 5,483.19	$ 5,483.19	$ 7,208.19	$ 7,208.19	$ 7,208.19	$ 7,208.19	$ 8,933.19	$ 8,933.19	$ 8,933.19	$ 8,933.19	$ 10,658.19	$ 10,658.19	$ 10,658.19	$ 10,658.19	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,000.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,500.00	$ 1,500.00	$ 1,500.00	$ 1,500.00	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @$ 1.006 /kW NSPL	$ 1,509.00	$ 1,509.00	$ 1,509.00	$ 1,509.00	$ 1,509.00	$ 2,012.00	$ 2,012.00	$ 2,012.00	$ 2,012.00	$ 2,515.00	$ 2,515.00	$ 2,515.00	$ 2,515.00	$ 3,018.00	$ 3,018.00	$ 3,018.00	$ 3,018.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 33.00	$ 99.00	$ 165.00	$ 240.90	$ 44.00	$ 132.00	$ 220.00	$ 321.20	$ 55.00	$ 165.00	$ 275.00	$ 401.50	$ 66.00	$ 198.00	$ 330.00	$ 481.80	
Sub-Total	$ 2,259.00	$ 2,292.00	$ 2,358.00	$ 2,424.00	$ 2,499.90	$ 3,056.00	$ 3,144.00	$ 3,232.00	$ 3,333.20	$ 3,820.00	$ 3,930.00	$ 4,040.00	$ 4,166.50	$ 4,584.00	$ 4,716.00	$ 4,848.00	$ 4,999.80	
PTC Charge																		
All kWh @ $ 0.05262 /kWh	$ -	$ 7,893.00	$ 23,679.00	$ 39,465.00	$ 57,618.90	$ 10,524.00	$ 31,572.00	$ 52,620.00	$ 76,825.20	$ 13,155.00	$ 39,465.00	$ 65,775.00	$ 96,031.50	$ 15,786.00	$ 47,358.00	$ 78,930.00	$ 115,237.80	
Sub Total	$ 7,742.19	$ 15,723.69	$ 31,686.69	$ 47,649.69	$ 66,007.14	$ 20,862.19	$ 42,146.19	$ 63,430.19	$ 87,906.79	$ 26,000.69	$ 52,605.69	$ 79,210.69	$ 109,806.44	$ 31,139.19	$ 63,065.19	$ 94,991.19	$ 131,706.09	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 7,742.19**	**$ 15,723.69**	**$ 31,686.69**	**$ 47,649.69**	**$ 66,007.14**	**$ 20,862.19**	**$ 42,146.19**	**$ 63,430.19**	**$ 87,906.79**	**$ 26,000.69**	**$ 52,605.69**	**$ 79,210.69**	**$ 109,806.44**	**$ 31,139.19**	**$ 63,065.19**	**$ 94,991.19**	**$ 131,706.09**	
% Increase	**65.20%**	**23.16%**	**9.54%**	**5.68%**	**3.66%**	**23.13%**	**9.49%**	**5.65%**	**3.64%**	**23.11%**	**9.47%**	**5.63%**	**3.62%**	**23.10%**	**9.45%**	**5.62%**	**3.62%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE TP - 12 HOUR ON PEAK TIME OF DAY
With Demands Up to 20,000 KW
At Average Levels of kWh Use

KW Demand																		
Total kW	5,000	5,000	5,000	5,000	5,000	10,000	10,000	10,000	10,000	15,000	15,000	15,000	15,000	20,000	20,000	20,000	20,000	
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730	
REACTIVE DEMAND																		
rkVA	284	284	284	284	284	567	567	567	567	851	851	851	851	1,134	1,134	1,134	1,134	
ENERGY USAGE																		
Monthly Energy Usage	0	500,000	1,500,000	2,500,000	3,650,000	1,000,000	3,000,000	5,000,000	7,300,000	1,500,000	4,500,000	7,500,000	10,950,000	2,000,000	6,000,000	10,000,000	14,600,000	
Total Energy Usage	0	500,000	1,500,000	2,500,000	3,650,000	1,000,000	3,000,000	5,000,000	7,300,000	1,500,000	4,500,000	7,500,000	10,950,000	2,000,000	6,000,000	10,000,000	14,600,000	

UNBUNDLED RATES - CURRENT

NUG Charge																		
All kWh @ 0.045 ¢/kWh	$ -	$ 225.00	$ 675.00	$ 1,125.00	$ 1,642.50	$ 450.00	$ 1,350.00	$ 2,250.00	$ 3,285.00	$ 675.00	$ 2,025.00	$ 3,375.00	$ 4,927.50	$ 900.00	$ 2,700.00	$ 4,500.00	$ 6,570.00	
Distribution																		
Distribution Charge @ $882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	
All kW @ $0.64/kW	$ 3,200.00	$ 3,200.00	$ 3,200.00	$ 3,200.00	$ 3,200.00	$ 6,400.00	$ 6,400.00	$ 6,400.00	$ 6,400.00	$ 9,600.00	$ 9,600.00	$ 9,600.00	$ 9,600.00	$ 12,800.00	$ 12,800.00	$ 12,800.00	$ 12,800.00	
Sub-Total	$ 4,082.16	$ 4,082.16	$ 4,082.16	$ 4,082.16	$ 4,082.16	$ 7,282.16	$ 7,282.16	$ 7,282.16	$ 7,282.16	$ 10,482.16	$ 10,482.16	$ 10,482.16	$ 10,482.16	$ 13,682.16	$ 13,682.16	$ 13,682.16	$ 13,682.16	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	
Smart Meter Charge @ $2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	
Default Service Support Charge @ $ 0.973 /kW NSPL	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 110.00	$ 330.00	$ 550.00	$ 803.00	$ 220.00	$ 660.00	$ 1,100.00	$ 1,606.00	$ 330.00	$ 990.00	$ 1,650.00	$ 2,409.00	$ 440.00	$ 1,320.00	$ 2,200.00	$ 3,212.00	
Sub-Total	$ 7,367.34	$ 7,477.34	$ 7,697.34	$ 7,917.34	$ 8,170.34	$ 14,952.34	$ 15,392.34	$ 15,832.34	$ 16,338.34	$ 22,427.34	$ 23,087.34	$ 23,747.34	$ 24,506.34	$ 29,902.34	$ 30,782.34	$ 31,662.34	$ 32,674.34	
PTC Charge																		
All kWh @ $ 0.04277 /kWh	$ -	$ 21,385.00	$ 64,155.00	$ 106,925.00	$ 156,110.50	$ 42,770.00	$ 128,310.00	$ 213,850.00	$ 312,221.00	$ 64,155.00	$ 192,465.00	$ 320,775.00	$ 468,331.50	$ 85,540.00	$ 256,620.00	$ 427,700.00	$ 624,442.00	
Sub Total	$ 11,449.50	$ 33,169.50	$ 76,609.50	$ 120,049.50	$ 170,005.50	$ 65,454.50	$ 152,334.50	$ 239,214.50	$ 339,126.50	$ 97,739.50	$ 228,059.50	$ 358,379.50	$ 508,247.50	$ 130,024.50	$ 303,784.50	$ 477,544.50	$ 677,368.50	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 11,449.50**	**$ 33,169.50**	**$ 76,609.50**	**$ 120,049.50**	**$ 170,005.50**	**$ 65,454.50**	**$ 152,334.50**	**$ 239,214.50**	**$ 339,126.50**	**$ 97,739.50**	**$ 228,059.50**	**$ 358,379.50**	**$ 508,247.50**	**$ 130,024.50**	**$ 303,784.50**	**$ 477,544.50**	**$ 677,368.50**	

UNBUNDLED RATES - PROPOSED

NUG Charge																		
All kWh @ 0.045 ¢/kWh	$ -	$ 225.00	$ 675.00	$ 1,125.00	$ 1,642.50	$ 450.00	$ 1,350.00	$ 2,250.00	$ 3,285.00	$ 675.00	$ 2,025.00	$ 3,375.00	$ 4,927.50	$ 900.00	$ 2,700.00	$ 4,500.00	$ 6,570.00	
Distribution																		
Distribution Charge @ $1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	
All kW @ $1.03/kW	$ 5,150.00	$ 5,150.00	$ 5,150.00	$ 5,150.00	$ 5,150.00	$ 10,300.00	$ 10,300.00	$ 10,300.00	$ 10,300.00	$ 15,450.00	$ 15,450.00	$ 15,450.00	$ 15,450.00	$ 20,600.00	$ 20,600.00	$ 20,600.00	$ 20,600.00	
Sub-Total	$ 6,299.15	$ 6,299.15	$ 6,299.15	$ 6,299.15	$ 6,299.15	$ 11,449.15	$ 11,449.15	$ 11,449.15	$ 11,449.15	$ 16,599.15	$ 16,599.15	$ 16,599.15	$ 16,599.15	$ 21,749.15	$ 21,749.15	$ 21,749.15	$ 21,749.15	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @$ 0.973 /kW NSPL	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 110.00	$ 330.00	$ 550.00	$ 803.00	$ 220.00	$ 660.00	$ 1,100.00	$ 1,606.00	$ 330.00	$ 990.00	$ 1,650.00	$ 2,409.00	$ 440.00	$ 1,320.00	$ 2,200.00	$ 3,212.00	
Sub-Total	$ 7,365.00	$ 7,475.00	$ 7,695.00	$ 7,915.00	$ 8,168.00	$ 14,950.00	$ 15,390.00	$ 15,830.00	$ 16,336.00	$ 22,425.00	$ 23,085.00	$ 23,745.00	$ 24,504.00	$ 29,900.00	$ 30,780.00	$ 31,660.00	$ 32,672.00	
PTC Charge																		
All kWh @ $ 0.04277 /kWh	$ -	$ 21,385.00	$ 64,155.00	$ 106,925.00	$ 156,110.50	$ 42,770.00	$ 128,310.00	$ 213,850.00	$ 312,221.00	$ 64,155.00	$ 192,465.00	$ 320,775.00	$ 468,331.50	$ 85,540.00	$ 256,620.00	$ 427,700.00	$ 624,442.00	
Sub Total	$ 13,664.15	$ 35,384.15	$ 78,824.15	$ 122,264.15	$ 172,220.15	$ 69,619.15	$ 156,499.15	$ 243,379.15	$ 343,291.15	$ 103,854.15	$ 234,174.15	$ 364,494.15	$ 514,362.15	$ 138,089.15	$ 311,849.15	$ 485,609.15	$ 685,433.15	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 13,664.15**	**$ 35,384.15**	**$ 78,824.15**	**$ 122,264.15**	**$ 172,220.15**	**$ 69,619.15**	**$ 156,499.15**	**$ 243,379.15**	**$ 343,291.15**	**$ 103,854.15**	**$ 234,174.15**	**$ 364,494.15**	**$ 514,362.15**	**$ 138,089.15**	**$ 311,849.15**	**$ 485,609.15**	**$ 685,433.15**	
% Increase	**19.34%**	**6.68%**	**2.89%**	**1.84%**	**1.30%**	**6.36%**	**2.73%**	**1.74%**	**1.23%**	**6.26%**	**2.68%**	**1.71%**	**1.20%**	**6.20%**	**2.65%**	**1.69%**	**1.19%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE TP - 12 HOUR ON PEAK TIME OF DAY
With Demands Over 20,000 KW
At Average Levels of kWh Use

KW Demand																	
Total kW	25,000	25,000	25,000	25,000	25,000	30,000	30,000	30,000	30,000	35,000	35,000	35,000	35,000	40,000	40,000	40,000	40,000
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730
REACTIVE DEMAND																	
rkVA	1,418	1,418	1,418	1,418	1,418	1,701	1,701	1,701	1,701	1,985	1,985	1,985	1,985	2,268	2,268	2,268	2,268
ENERGY USAGE																	
Monthly Energy Usage	0	2,500,000	7,500,000	12,500,000	18,250,000	3,000,000	9,000,000	15,000,000	21,900,000	3,500,000	10,500,000	17,500,000	25,550,000	4,000,000	12,000,000	20,000,000	29,200,000
Total Energy Usage	0	2,500,000	7,500,000	12,500,000	18,250,000	3,000,000	9,000,000	15,000,000	21,900,000	3,500,000	10,500,000	17,500,000	25,550,000	4,000,000	12,000,000	20,000,000	29,200,000

UNBUNDLED RATES - CURRENT

NUG Charge																	
All kWh @ 0.045 ¢/kWh	$ -	$ 1,125.00	$ 3,375.00	$ 5,625.00	$ 8,212.50	$ 1,350.00	$ 4,050.00	$ 6,750.00	$ 9,855.00	$ 1,575.00	$ 4,725.00	$ 7,875.00	$ 11,497.50	$ 1,800.00	$ 5,400.00	$ 9,000.00	$ 13,140.00
Distribution																	
Distribution Charge @ $882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16
All kW @ $0.64/kW	$ 16,000.00	$ 16,000.00	$ 16,000.00	$ 16,000.00	$ 16,000.00	$ 19,200.00	$ 19,200.00	$ 19,200.00	$ 19,200.00	$ 22,400.00	$ 22,400.00	$ 22,400.00	$ 22,400.00	$ 25,600.00	$ 25,600.00	$ 25,600.00	$ 25,600.00
Sub-Total	$ 16,882.16	$ 16,882.16	$ 16,882.16	$ 16,882.16	$ 16,882.16	$ 20,082.16	$ 20,082.16	$ 20,082.16	$ 20,082.16	$ 23,282.16	$ 23,282.16	$ 23,282.16	$ 23,282.16	$ 26,482.16	$ 26,482.16	$ 26,482.16	$ 26,482.16
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ 20,000.00
Smart Meter Charge @ $2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34
Default Service Support Charge @ $ 0.973 /kW NSPL	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 38,920.00	$ 38,920.00	$ 38,920.00	$ 38,920.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 550.00	$ 1,650.00	$ 2,750.00	$ 4,015.00	$ 660.00	$ 1,980.00	$ 3,300.00	$ 4,818.00	$ 770.00	$ 2,310.00	$ 3,850.00	$ 5,621.00	$ 880.00	$ 2,640.00	$ 4,400.00	$ 6,424.00
Sub-Total	$ 36,827.34	$ 37,377.34	$ 38,477.34	$ 39,577.34	$ 40,842.34	$ 44,852.34	$ 46,172.34	$ 47,492.34	$ 49,010.34	$ 52,327.34	$ 53,867.34	$ 55,407.34	$ 57,178.34	$ 59,802.34	$ 61,562.34	$ 63,322.34	$ 65,346.34
PTC Charge																	
All kWh @ $ 0.04277 /kWh	$ -	$ 106,925.00	$ 320,775.00	$ 534,625.00	$ 780,552.50	$ 128,310.00	$ 384,930.00	$ 641,550.00	$ 936,663.00	$ 149,695.00	$ 449,085.00	$ 748,475.00	$ 1,092,773.50	$ 171,080.00	$ 513,240.00	$ 855,400.00	$ 1,248,884.00
Sub Total	$ 53,709.50	$ 162,309.50	$ 379,509.50	$ 596,709.50	$ 846,489.50	$ 194,594.50	$ 455,234.50	$ 715,874.50	$ 1,015,610.50	$ 226,879.50	$ 530,959.50	$ 835,039.50	$ 1,184,731.50	$ 259,164.50	$ 606,684.50	$ 954,204.50	$ 1,353,852.50
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 53,709.50**	**$ 162,309.50**	**$ 379,509.50**	**$ 596,709.50**	**$ 846,489.50**	**$ 194,594.50**	**$ 455,234.50**	**$ 715,874.50**	**$ 1,015,610.50**	**$ 226,879.50**	**$ 530,959.50**	**$ 835,039.50**	**$ 1,184,731.50**	**$ 259,164.50**	**$ 606,684.50**	**$ 954,204.50**	**$ 1,353,852.50**

UNBUNDLED RATES - PROPOSED

NUG Charge																	
All kWh @ 0.045 ¢/kWh	$ -	$ 1,125.00	$ 3,375.00	$ 5,625.00	$ 8,212.50	$ 1,350.00	$ 4,050.00	$ 6,750.00	$ 9,855.00	$ 1,575.00	$ 4,725.00	$ 7,875.00	$ 11,497.50	$ 1,800.00	$ 5,400.00	$ 9,000.00	$ 13,140.00
Distribution																	
Distribution Charge @ $1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15
All kW @ $1.03/kW	$ 25,750.00	$ 25,750.00	$ 25,750.00	$ 25,750.00	$ 25,750.00	$ 30,900.00	$ 30,900.00	$ 30,900.00	$ 30,900.00	$ 36,050.00	$ 36,050.00	$ 36,050.00	$ 36,050.00	$ 41,200.00	$ 41,200.00	$ 41,200.00	$ 41,200.00
Sub-Total	$ 26,899.15	$ 26,899.15	$ 26,899.15	$ 26,899.15	$ 26,899.15	$ 32,049.15	$ 32,049.15	$ 32,049.15	$ 32,049.15	$ 37,199.15	$ 37,199.15	$ 37,199.15	$ 37,199.15	$ 42,349.15	$ 42,349.15	$ 42,349.15	$ 42,349.15
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ 20,000.00
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @$ 0.973 /kW NSPL	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 38,920.00	$ 38,920.00	$ 38,920.00	$ 38,920.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 550.00	$ 1,650.00	$ 2,750.00	$ 4,015.00	$ 660.00	$ 1,980.00	$ 3,300.00	$ 4,818.00	$ 770.00	$ 2,310.00	$ 3,850.00	$ 5,621.00	$ 880.00	$ 2,640.00	$ 4,400.00	$ 6,424.00
Sub-Total	$ 36,825.00	$ 37,375.00	$ 38,475.00	$ 39,575.00	$ 40,840.00	$ 44,850.00	$ 46,170.00	$ 47,490.00	$ 49,008.00	$ 52,325.00	$ 53,865.00	$ 55,405.00	$ 57,176.00	$ 59,800.00	$ 61,560.00	$ 63,320.00	$ 65,344.00
PTC Charge																	
All kWh @ $ 0.04277 /kWh	$ -	$ 106,925.00	$ 320,775.00	$ 534,625.00	$ 780,552.50	$ 128,310.00	$ 384,930.00	$ 641,550.00	$ 936,663.00	$ 149,695.00	$ 449,085.00	$ 748,475.00	$ 1,092,773.50	$ 171,080.00	$ 513,240.00	$ 855,400.00	$ 1,248,884.00
Sub Total	$ 63,724.15	$ 172,324.15	$ 389,524.15	$ 606,724.15	$ 856,504.15	$ 206,559.15	$ 467,199.15	$ 727,839.15	$ 1,027,575.15	$ 240,794.15	$ 544,874.15	$ 848,954.15	$ 1,198,646.15	$ 275,029.15	$ 622,549.15	$ 970,069.15	$ 1,369,717.15
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 63,724.15**	**$ 172,324.15**	**$ 389,524.15**	**$ 606,724.15**	**$ 856,504.15**	**$ 206,559.15**	**$ 467,199.15**	**$ 727,839.15**	**$ 1,027,575.15**	**$ 240,794.15**	**$ 544,874.15**	**$ 848,954.15**	**$ 1,198,646.15**	**$ 275,029.15**	**$ 622,549.15**	**$ 970,069.15**	**$ 1,369,717.15**
% Increase	**18.65%**	**6.17%**	**2.64%**	**1.68%**	**1.18%**	**6.15%**	**2.63%**	**1.67%**	**1.18%**	**6.13%**	**2.62%**	**1.67%**	**1.17%**	**6.12%**	**2.61%**	**1.66%**	**1.17%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE TP - 12 HOUR ON PEAK TIME OF DAY - 115 KV OR GREATER DISCOUNT
With Demands Up to 20,000 KW
At Average Levels of kWh Use

KW Demand																		
Total kW	5,000	5,000	5,000	5,000	5,000	10,000	10,000	10,000	10,000	15,000	15,000	15,000	15,000	20,000	20,000	20,000	20,000	
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730	
REACTIVE DEMAND																		
rkVA	284	284	284	284	284	567	567	567	567	851	851	851	851	1,134	1,134	1,134	1,134	
ENERGY USAGE																		
Monthly Energy Usage	0	500,000	1,500,000	2,500,000	3,650,000	1,000,000	3,000,000	5,000,000	7,300,000	1,500,000	4,500,000	7,500,000	10,950,000	2,000,000	6,000,000	10,000,000	14,600,000	
Total Energy Usage	0	500,000	1,500,000	2,500,000	3,650,000	1,000,000	3,000,000	5,000,000	7,300,000	1,500,000	4,500,000	7,500,000	10,950,000	2,000,000	6,000,000	10,000,000	14,600,000	
UNBUNDLED RATES - CURRENT																		
NUG Charge																		
All kWh @ 0.045 ¢/kWh	$ -	$ 225.00	$ 675.00	$ 1,125.00	$ 1,642.50	$ 450.00	$ 1,350.00	$ 2,250.00	$ 3,285.00	$ 675.00	$ 2,025.00	$ 3,375.00	$ 4,927.50	$ 900.00	$ 2,700.00	$ 4,500.00	$ 6,570.00	
Distribution																		
Distribution Charge @ $882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	
All kW @ $0.37/kW	$ 1,850.00	$ 1,850.00	$ 1,850.00	$ 1,850.00	$ 1,850.00	$ 3,700.00	$ 3,700.00	$ 3,700.00	$ 3,700.00	$ 5,550.00	$ 5,550.00	$ 5,550.00	$ 5,550.00	$ 7,400.00	$ 7,400.00	$ 7,400.00	$ 7,400.00	
Sub-Total	$ 2,732.16	$ 2,732.16	$ 2,732.16	$ 2,732.16	$ 2,732.16	$ 4,582.16	$ 4,582.16	$ 4,582.16	$ 4,582.16	$ 6,432.16	$ 6,432.16	$ 6,432.16	$ 6,432.16	$ 8,282.16	$ 8,282.16	$ 8,282.16	$ 8,282.16	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	
Smart Meter Charge @ $2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	
Default Service Support Charge @$ 0.973 /kW NSPL	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 110.00	$ 330.00	$ 550.00	$ 803.00	$ 220.00	$ 660.00	$ 1,100.00	$ 1,606.00	$ 330.00	$ 990.00	$ 1,650.00	$ 2,409.00	$ 440.00	$ 1,320.00	$ 2,200.00	$ 3,212.00	
Sub-Total	$ 7,367.34	$ 7,477.34	$ 7,697.34	$ 7,917.34	$ 8,170.34	$ 14,952.34	$ 15,392.34	$ 15,832.34	$ 16,338.34	$ 22,427.34	$ 23,087.34	$ 23,747.34	$ 24,506.34	$ 29,902.34	$ 30,782.34	$ 31,662.34	$ 32,674.34	
PTC Charge																		
All kWh @ $ 0.04277 /kWh	$ -	$ 21,385.00	$ 64,155.00	$ 106,925.00	$ 156,110.50	$ 42,770.00	$ 128,310.00	$ 213,850.00	$ 312,221.00	$ 64,155.00	$ 192,465.00	$ 320,775.00	$ 468,331.50	$ 85,540.00	$ 256,620.00	$ 427,700.00	$ 624,442.00	
Sub Total	$ 10,099.50	$ 31,819.50	$ 75,259.50	$ 118,699.50	$ 168,655.50	$ 62,754.50	$ 149,634.50	$ 236,514.50	$ 336,426.50	$ 93,689.50	$ 224,009.50	$ 354,329.50	$ 504,197.50	$ 124,624.50	$ 298,384.50	$ 472,144.50	$ 671,968.50	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 10,099.50**	**$ 31,819.50**	**$ 75,259.50**	**$ 118,699.50**	**$ 168,655.50**	**$ 62,754.50**	**$ 149,634.50**	**$ 236,514.50**	**$ 336,426.50**	**$ 93,689.50**	**$ 224,009.50**	**$ 354,329.50**	**$ 504,197.50**	**$ 124,624.50**	**$ 298,384.50**	**$ 472,144.50**	**$ 671,968.50**	
UNBUNDLED RATES - PROPOSED																		
NUG Charge																		
All kWh @ 0.045 ¢/kWh	$ -	$ 225.00	$ 675.00	$ 1,125.00	$ 1,642.50	$ 450.00	$ 1,350.00	$ 2,250.00	$ 3,285.00	$ 675.00	$ 2,025.00	$ 3,375.00	$ 4,927.50	$ 900.00	$ 2,700.00	$ 4,500.00	$ 6,570.00	
Distribution																		
Distribution Charge @ $1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	
All kW @ $0.72/kW	$ 3,600.00	$ 3,600.00	$ 3,600.00	$ 3,600.00	$ 3,600.00	$ 7,200.00	$ 7,200.00	$ 7,200.00	$ 7,200.00	$ 10,800.00	$ 10,800.00	$ 10,800.00	$ 10,800.00	$ 14,400.00	$ 14,400.00	$ 14,400.00	$ 14,400.00	
Sub-Total	$ 4,749.15	$ 4,749.15	$ 4,749.15	$ 4,749.15	$ 4,749.15	$ 8,349.15	$ 8,349.15	$ 8,349.15	$ 8,349.15	$ 11,949.15	$ 11,949.15	$ 11,949.15	$ 11,949.15	$ 15,549.15	$ 15,549.15	$ 15,549.15	$ 15,549.15	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @$ 0.973 /kW NSPL	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 110.00	$ 330.00	$ 550.00	$ 803.00	$ 220.00	$ 660.00	$ 1,100.00	$ 1,606.00	$ 330.00	$ 990.00	$ 1,650.00	$ 2,409.00	$ 440.00	$ 1,320.00	$ 2,200.00	$ 3,212.00	
Sub-Total	$ 7,365.00	$ 7,475.00	$ 7,695.00	$ 7,915.00	$ 8,168.00	$ 14,950.00	$ 15,390.00	$ 15,830.00	$ 16,336.00	$ 22,425.00	$ 23,085.00	$ 23,745.00	$ 24,504.00	$ 29,900.00	$ 30,780.00	$ 31,660.00	$ 32,672.00	
PTC Charge																		
All kWh @ $ 0.04277 /kWh	$ -	$ 21,385.00	$ 64,155.00	$ 106,925.00	$ 156,110.50	$ 42,770.00	$ 128,310.00	$ 213,850.00	$ 312,221.00	$ 64,155.00	$ 192,465.00	$ 320,775.00	$ 468,331.50	$ 85,540.00	$ 256,620.00	$ 427,700.00	$ 624,442.00	
Sub Total	$ 12,114.15	$ 33,834.15	$ 77,274.15	$ 120,714.15	$ 170,670.15	$ 66,519.15	$ 153,399.15	$ 240,279.15	$ 340,191.15	$ 99,204.15	$ 229,524.15	$ 359,844.15	$ 509,712.15	$ 131,889.15	$ 305,649.15	$ 479,409.15	$ 679,233.15	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 12,114.15**	**$ 33,834.15**	**$ 77,274.15**	**$ 120,714.15**	**$ 170,670.15**	**$ 66,519.15**	**$ 153,399.15**	**$ 240,279.15**	**$ 340,191.15**	**$ 99,204.15**	**$ 229,524.15**	**$ 359,844.15**	**$ 509,712.15**	**$ 131,889.15**	**$ 305,649.15**	**$ 479,409.15**	**$ 679,233.15**	
% Increase	**19.95%**	**6.33%**	**2.68%**	**1.70%**	**1.19%**	**6.00%**	**2.52%**	**1.59%**	**1.12%**	**5.89%**	**2.46%**	**1.56%**	**1.09%**	**5.83%**	**2.43%**	**1.54%**	**1.08%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE TP - 12 HOUR ON PEAK TIME OF DAY - 115 KV OR GREATER DISCOUNT
With Demands Over 20,000 KW
At Average Levels of kWh Use

KW Demand																	
Total kW	25,000	25,000	25,000	25,000	25,000	30,000	30,000	30,000	30,000	35,000	35,000	35,000	35,000	40,000	40,000	40,000	40,000
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730
REACTIVE DEMAND																	
rkVA	1,418	1,418	1,418	1,418	1,418	1,701	1,701	1,701	1,701	1,985	1,985	1,985	1,985	2,268	2,268	2,268	2,268
ENERGY USAGE																	
Monthly Energy Usage	0	2,500,000	7,500,000	12,500,000	18,250,000	3,000,000	9,000,000	15,000,000	21,900,000	3,500,000	10,500,000	17,500,000	25,550,000	4,000,000	12,000,000	20,000,000	29,200,000
Total Energy Usage	0	2,500,000	7,500,000	12,500,000	18,250,000	3,000,000	9,000,000	15,000,000	21,900,000	3,500,000	10,500,000	17,500,000	25,550,000	4,000,000	12,000,000	20,000,000	29,200,000

UNBUNDLED RATES - CURRENT

NUG Charge																	
All kWh @ 0.045 ¢/kWh	$ -	$ 1,125.00	$ 3,375.00	$ 5,625.00	$ 8,212.50	$ 1,350.00	$ 4,050.00	$ 6,750.00	$ 9,855.00	$ 1,575.00	$ 4,725.00	$ 7,875.00	$ 11,497.50	$ 1,800.00	$ 5,400.00	$ 9,000.00	$ 13,140.00
Distribution																	
Distribution Charge @ $882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16
All kW @ $0.37/kW	$ 9,250.00	$ 9,250.00	$ 9,250.00	$ 9,250.00	$ 9,250.00	$ 11,100.00	$ 11,100.00	$ 11,100.00	$ 11,100.00	$ 12,950.00	$ 12,950.00	$ 12,950.00	$ 12,950.00	$ 14,800.00	$ 14,800.00	$ 14,800.00	$ 14,800.00
Sub-Total	$ 10,132.16	$ 10,132.16	$ 10,132.16	$ 10,132.16	$ 10,132.16	$ 11,982.16	$ 11,982.16	$ 11,982.16	$ 11,982.16	$ 13,832.16	$ 13,832.16	$ 13,832.16	$ 13,832.16	$ 15,682.16	$ 15,682.16	$ 15,682.16	$ 15,682.16
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ 20,000.00
Smart Meter Charge @ $2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34
Default Service Support Charge @$ 0.973 /kW NSPL	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 38,920.00	$ 38,920.00	$ 38,920.00	$ 38,920.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 550.00	$ 1,650.00	$ 2,750.00	$ 4,015.00	$ 660.00	$ 1,980.00	$ 3,300.00	$ 4,818.00	$ 770.00	$ 2,310.00	$ 3,850.00	$ 5,621.00	$ 880.00	$ 2,640.00	$ 4,400.00	$ 6,424.00
Sub-Total	$ 36,827.34	$ 37,377.34	$ 38,477.34	$ 39,577.34	$ 40,842.34	$ 44,852.34	$ 46,172.34	$ 47,492.34	$ 49,010.34	$ 52,327.34	$ 53,867.34	$ 55,407.34	$ 57,178.34	$ 59,802.34	$ 61,562.34	$ 63,322.34	$ 65,346.34
PTC Charge																	
All kWh @ $ 0.04277 /kWh	$ -	$ 106,925.00	$ 320,775.00	$ 534,625.00	$ 780,552.50	$ 128,310.00	$ 384,930.00	$ 641,550.00	$ 936,663.00	$ 149,695.00	$ 449,085.00	$ 748,475.00	$ 1,092,773.50	$ 171,080.00	$ 513,240.00	$ 855,400.00	$ 1,248,884.00
Sub Total	$ 46,959.50	$ 155,559.50	$ 372,759.50	$ 589,959.50	$ 839,739.50	$ 186,494.50	$ 447,134.50	$ 707,774.50	$ 1,007,510.50	$ 217,429.50	$ 521,509.50	$ 825,589.50	$ 1,175,281.50	$ 248,364.50	$ 595,884.50	$ 943,404.50	$ 1,343,052.50
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 46,959.50**	**$ 155,559.50**	**$ 372,759.50**	**$ 589,959.50**	**$ 839,739.50**	**$ 186,494.50**	**$ 447,134.50**	**$ 707,774.50**	**$ 1,007,510.50**	**$ 217,429.50**	**$ 521,509.50**	**$ 825,589.50**	**$ 1,175,281.50**	**$ 248,364.50**	**$ 595,884.50**	**$ 943,404.50**	**$ 1,343,052.50**

UNBUNDLED RATES - PROPOSED

NUG Charge																	
All kWh @ 0.045 ¢/kWh	$ -	$ 1,125.00	$ 3,375.00	$ 5,625.00	$ 8,212.50	$ 1,350.00	$ 4,050.00	$ 6,750.00	$ 9,855.00	$ 1,575.00	$ 4,725.00	$ 7,875.00	$ 11,497.50	$ 1,800.00	$ 5,400.00	$ 9,000.00	$ 13,140.00
Distribution																	
Distribution Charge @ $1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15
All kW @ $0.72/kW	$ 18,000.00	$ 18,000.00	$ 18,000.00	$ 18,000.00	$ 18,000.00	$ 21,600.00	$ 21,600.00	$ 21,600.00	$ 21,600.00	$ 25,200.00	$ 25,200.00	$ 25,200.00	$ 25,200.00	$ 28,800.00	$ 28,800.00	$ 28,800.00	$ 28,800.00
Sub-Total	$ 19,149.15	$ 19,149.15	$ 19,149.15	$ 19,149.15	$ 19,149.15	$ 22,749.15	$ 22,749.15	$ 22,749.15	$ 22,749.15	$ 26,349.15	$ 26,349.15	$ 26,349.15	$ 26,349.15	$ 29,949.15	$ 29,949.15	$ 29,949.15	$ 29,949.15
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ 20,000.00
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @$ 0.973 /kW NSPL	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 38,920.00	$ 38,920.00	$ 38,920.00	$ 38,920.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 550.00	$ 1,650.00	$ 2,750.00	$ 4,015.00	$ 660.00	$ 1,980.00	$ 3,300.00	$ 4,818.00	$ 770.00	$ 2,310.00	$ 3,850.00	$ 5,621.00	$ 880.00	$ 2,640.00	$ 4,400.00	$ 6,424.00
Sub-Total	$ 36,825.00	$ 37,375.00	$ 38,475.00	$ 39,575.00	$ 40,840.00	$ 44,850.00	$ 46,170.00	$ 47,490.00	$ 49,008.00	$ 52,325.00	$ 53,865.00	$ 55,405.00	$ 57,176.00	$ 59,800.00	$ 61,560.00	$ 63,320.00	$ 65,344.00
PTC Charge																	
All kWh @ $ 0.04277 /kWh	$ -	$ 106,925.00	$ 320,775.00	$ 534,625.00	$ 780,552.50	$ 128,310.00	$ 384,930.00	$ 641,550.00	$ 936,663.00	$ 149,695.00	$ 449,085.00	$ 748,475.00	$ 1,092,773.50	$ 171,080.00	$ 513,240.00	$ 855,400.00	$ 1,248,884.00
Sub Total	$ 55,974.15	$ 164,574.15	$ 381,774.15	$ 598,974.15	$ 848,754.15	$ 197,259.15	$ 457,899.15	$ 718,539.15	$ 1,018,275.15	$ 229,944.15	$ 534,024.15	$ 838,104.15	$ 1,187,796.15	$ 262,629.15	$ 610,149.15	$ 957,669.15	$ 1,357,317.15
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 55,974.15**	**$ 164,574.15**	**$ 381,774.15**	**$ 598,974.15**	**$ 848,754.15**	**$ 197,259.15**	**$ 457,899.15**	**$ 718,539.15**	**$ 1,018,275.15**	**$ 229,944.15**	**$ 534,024.15**	**$ 838,104.15**	**$ 1,187,796.15**	**$ 262,629.15**	**$ 610,149.15**	**$ 957,669.15**	**$ 1,357,317.15**
% Increase	**19.20%**	**5.79%**	**2.42%**	**1.53%**	**1.07%**	**5.77%**	**2.41%**	**1.52%**	**1.07%**	**5.76%**	**2.40%**	**1.52%**	**1.06%**	**5.74%**	**2.39%**	**1.51%**	**1.06%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE TP - 8 HOUR ON PEAK TIME OF DAY vs RATE TP
With Demands Up to 20,000 KW
At Average Levels of kWh Use

KW Demand																		
Total kW	5,000	5,000	5,000	5,000	5,000	10,000	10,000	10,000	10,000	15,000	15,000	15,000	15,000	20,000	20,000	20,000	20,000	
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730	
REACTIVE DEMAND																		
rkVA	284	284	284	284	284	567	567	567	567	851	851	851	851	1,134	1,134	1,134	1,134	
ENERGY USAGE																		
Monthly Energy Usage	0	500,000	1,500,000	2,500,000	3,650,000	1,000,000	3,000,000	5,000,000	7,300,000	1,500,000	4,500,000	7,500,000	10,950,000	2,000,000	6,000,000	10,000,000	14,600,000	
Total Energy Usage	0	500,000	1,500,000	2,500,000	3,650,000	1,000,000	3,000,000	5,000,000	7,300,000	1,500,000	4,500,000	7,500,000	10,950,000	2,000,000	6,000,000	10,000,000	14,600,000	

UNBUNDLED RATES - CURRENT

NUG Charge																		
All kWh @ 0.045 ¢/kWh	$ -	$ 225.00	$ 675.00	$ 1,125.00	$ 1,642.50	$ 450.00	$ 1,350.00	$ 2,250.00	$ 3,285.00	$ 675.00	$ 2,025.00	$ 3,375.00	$ 4,927.50	$ 900.00	$ 2,700.00	$ 4,500.00	$ 6,570.00	
Distribution																		
Distribution Charge @ $882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	
All kW @ $0.64/kW	$ 3,200.00	$ 3,200.00	$ 3,200.00	$ 3,200.00	$ 3,200.00	$ 6,400.00	$ 6,400.00	$ 6,400.00	$ 6,400.00	$ 9,600.00	$ 9,600.00	$ 9,600.00	$ 9,600.00	$ 12,800.00	$ 12,800.00	$ 12,800.00	$ 12,800.00	
Sub-Total	$ 4,082.16	$ 4,082.16	$ 4,082.16	$ 4,082.16	$ 4,082.16	$ 7,282.16	$ 7,282.16	$ 7,282.16	$ 7,282.16	$ 10,482.16	$ 10,482.16	$ 10,482.16	$ 10,482.16	$ 13,682.16	$ 13,682.16	$ 13,682.16	$ 13,682.16	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	
Smart Meter Charge @ $2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	
Default Service Support Charge @ $ 0.973 /kW NSPL	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 110.00	$ 330.00	$ 550.00	$ 803.00	$ 220.00	$ 660.00	$ 1,100.00	$ 1,606.00	$ 330.00	$ 990.00	$ 1,650.00	$ 2,409.00	$ 440.00	$ 1,320.00	$ 2,200.00	$ 3,212.00	
Sub-Total	$ 7,367.34	$ 7,477.34	$ 7,697.34	$ 7,917.34	$ 8,170.34	$ 14,952.34	$ 15,392.34	$ 15,832.34	$ 16,338.34	$ 22,427.34	$ 23,087.34	$ 23,747.34	$ 24,506.34	$ 29,902.34	$ 30,782.34	$ 31,662.34	$ 32,674.34	
PTC Charge																		
All kWh @ $ 0.04277 /kWh	$ -	$ 21,385.00	$ 64,155.00	$ 106,925.00	$ 156,110.50	$ 42,770.00	$ 128,310.00	$ 213,850.00	$ 312,221.00	$ 64,155.00	$ 192,465.00	$ 320,775.00	$ 468,331.50	$ 85,540.00	$ 256,620.00	$ 427,700.00	$ 624,442.00	
Sub Total	$ 11,449.50	$ 33,169.50	$ 76,609.50	$ 120,049.50	$ 170,005.50	$ 65,454.50	$ 152,334.50	$ 239,214.50	$ 339,126.50	$ 97,739.50	$ 228,059.50	$ 358,379.50	$ 508,247.50	$ 130,024.50	$ 303,784.50	$ 477,544.50	$ 677,368.50	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 11,449.50**	**$ 33,169.50**	**$ 76,609.50**	**$ 120,049.50**	**$ 170,005.50**	**$ 65,454.50**	**$ 152,334.50**	**$ 239,214.50**	**$ 339,126.50**	**$ 97,739.50**	**$ 228,059.50**	**$ 358,379.50**	**$ 508,247.50**	**$ 130,024.50**	**$ 303,784.50**	**$ 477,544.50**	**$ 677,368.50**	

UNBUNDLED RATES - PROPOSED

NUG Charge																		
All kWh @ 0.045 ¢/kWh	$ -	$ 225.00	$ 675.00	$ 1,125.00	$ 1,642.50	$ 450.00	$ 1,350.00	$ 2,250.00	$ 3,285.00	$ 675.00	$ 2,025.00	$ 3,375.00	$ 4,927.50	$ 900.00	$ 2,700.00	$ 4,500.00	$ 6,570.00	
Distribution																		
Distribution Charge @ $1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	
All kW @ $1.03/kW	$ 5,150.00	$ 5,150.00	$ 5,150.00	$ 5,150.00	$ 5,150.00	$ 10,300.00	$ 10,300.00	$ 10,300.00	$ 10,300.00	$ 15,450.00	$ 15,450.00	$ 15,450.00	$ 15,450.00	$ 20,600.00	$ 20,600.00	$ 20,600.00	$ 20,600.00	
Sub-Total	$ 6,299.15	$ 6,299.15	$ 6,299.15	$ 6,299.15	$ 6,299.15	$ 11,449.15	$ 11,449.15	$ 11,449.15	$ 11,449.15	$ 16,599.15	$ 16,599.15	$ 16,599.15	$ 16,599.15	$ 21,749.15	$ 21,749.15	$ 21,749.15	$ 21,749.15	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @$ 0.973 /kW NSPL	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 110.00	$ 330.00	$ 550.00	$ 803.00	$ 220.00	$ 660.00	$ 1,100.00	$ 1,606.00	$ 330.00	$ 990.00	$ 1,650.00	$ 2,409.00	$ 440.00	$ 1,320.00	$ 2,200.00	$ 3,212.00	
Sub-Total	$ 7,365.00	$ 7,475.00	$ 7,695.00	$ 7,915.00	$ 8,168.00	$ 14,950.00	$ 15,390.00	$ 15,830.00	$ 16,336.00	$ 22,425.00	$ 23,085.00	$ 23,745.00	$ 24,504.00	$ 29,900.00	$ 30,780.00	$ 31,660.00	$ 32,672.00	
PTC Charge																		
All kWh @ $ 0.04277 /kWh	$ -	$ 21,385.00	$ 64,155.00	$ 106,925.00	$ 156,110.50	$ 42,770.00	$ 128,310.00	$ 213,850.00	$ 312,221.00	$ 64,155.00	$ 192,465.00	$ 320,775.00	$ 468,331.50	$ 85,540.00	$ 256,620.00	$ 427,700.00	$ 624,442.00	
Sub Total	$ 13,664.15	$ 35,384.15	$ 78,824.15	$ 122,264.15	$ 172,220.15	$ 69,619.15	$ 156,499.15	$ 243,379.15	$ 343,291.15	$ 103,854.15	$ 234,174.15	$ 364,494.15	$ 514,362.15	$ 138,089.15	$ 311,849.15	$ 485,609.15	$ 685,433.15	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 13,664.15**	**$ 35,384.15**	**$ 78,824.15**	**$ 122,264.15**	**$ 172,220.15**	**$ 69,619.15**	**$ 156,499.15**	**$ 243,379.15**	**$ 343,291.15**	**$ 103,854.15**	**$ 234,174.15**	**$ 364,494.15**	**$ 514,362.15**	**$ 138,089.15**	**$ 311,849.15**	**$ 485,609.15**	**$ 685,433.15**	
% Increase	**19.34%**	**6.68%**	**2.89%**	**1.84%**	**1.30%**	**6.36%**	**2.73%**	**1.74%**	**1.23%**	**6.26%**	**2.68%**	**1.71%**	**1.20%**	**6.20%**	**2.65%**	**1.69%**	**1.19%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE TP - 8 HOUR ON PEAK TIME OF DAY vs RATE TP
With Demands Over 20,000 KW
At Average Levels of kWh Use

KW Demand																	
Total kW	25,000	25,000	25,000	25,000	25,000	30,000	30,000	30,000	30,000	35,000	35,000	35,000	35,000	40,000	40,000	40,000	40,000
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730
REACTIVE DEMAND																	
rkVA	1,418	1,418	1,418	1,418	1,418	1,701	1,701	1,701	1,701	1,985	1,985	1,985	1,985	2,268	2,268	2,268	2,268
ENERGY USAGE																	
Monthly Energy Usage	0	2,500,000	7,500,000	12,500,000	18,250,000	3,000,000	9,000,000	15,000,000	21,900,000	3,500,000	10,500,000	17,500,000	25,550,000	4,000,000	12,000,000	20,000,000	29,200,000
Total Energy Usage	0	2,500,000	7,500,000	12,500,000	18,250,000	3,000,000	9,000,000	15,000,000	21,900,000	3,500,000	10,500,000	17,500,000	25,550,000	4,000,000	12,000,000	20,000,000	29,200,000

UNBUNDLED RATES - CURRENT

NUG Charge																	
All kWh @ 0.045 ¢/kWh	$ -	$ 1,125.00	$ 3,375.00	$ 5,625.00	$ 8,212.50	$ 1,350.00	$ 4,050.00	$ 6,750.00	$ 9,855.00	$ 1,575.00	$ 4,725.00	$ 7,875.00	$ 11,497.50	$ 1,800.00	$ 5,400.00	$ 9,000.00	$ 13,140.00
Distribution																	
Distribution Charge @ $882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16
All kW @ $0.64/kW	$ 16,000.00	$ 16,000.00	$ 16,000.00	$ 16,000.00	$ 16,000.00	$ 19,200.00	$ 19,200.00	$ 19,200.00	$ 19,200.00	$ 22,400.00	$ 22,400.00	$ 22,400.00	$ 22,400.00	$ 25,600.00	$ 25,600.00	$ 25,600.00	$ 25,600.00
Sub-Total	$ 16,882.16	$ 16,882.16	$ 16,882.16	$ 16,882.16	$ 16,882.16	$ 20,082.16	$ 20,082.16	$ 20,082.16	$ 20,082.16	$ 23,282.16	$ 23,282.16	$ 23,282.16	$ 23,282.16	$ 26,482.16	$ 26,482.16	$ 26,482.16	$ 26,482.16
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ 20,000.00
Smart Meter Charge @ $2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34
Default Service Support Charge @ $ 0.973 /kW NSPL	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 38,920.00	$ 38,920.00	$ 38,920.00	$ 38,920.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 550.00	$ 1,650.00	$ 2,750.00	$ 4,015.00	$ 660.00	$ 1,980.00	$ 3,300.00	$ 4,818.00	$ 770.00	$ 2,310.00	$ 3,850.00	$ 5,621.00	$ 880.00	$ 2,640.00	$ 4,400.00	$ 6,424.00
Sub-Total	$ 36,827.34	$ 37,377.34	$ 38,477.34	$ 39,577.34	$ 40,842.34	$ 44,852.34	$ 46,172.34	$ 47,492.34	$ 49,010.34	$ 52,327.34	$ 53,867.34	$ 55,407.34	$ 57,178.34	$ 59,802.34	$ 61,562.34	$ 63,322.34	$ 65,346.34
PTC Charge																	
All kWh @ $ 0.04277 /kWh	$ -	$ 106,925.00	$ 320,775.00	$ 534,625.00	$ 780,552.50	$ 128,310.00	$ 384,930.00	$ 641,550.00	$ 936,663.00	$ 149,695.00	$ 449,085.00	$ 748,475.00	$ 1,092,773.50	$ 171,080.00	$ 513,240.00	$ 855,400.00	$ 1,248,884.00
Sub Total	$ 53,709.50	$ 162,309.50	$ 379,509.50	$ 596,709.50	$ 846,489.50	$ 194,594.50	$ 455,234.50	$ 715,874.50	$ 1,015,610.50	$ 226,879.50	$ 530,959.50	$ 835,039.50	$ 1,184,731.50	$ 259,164.50	$ 606,684.50	$ 954,204.50	$ 1,353,852.50
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 53,709.50**	**$ 162,309.50**	**$ 379,509.50**	**$ 596,709.50**	**$ 846,489.50**	**$ 194,594.50**	**$ 455,234.50**	**$ 715,874.50**	**$ 1,015,610.50**	**$ 226,879.50**	**$ 530,959.50**	**$ 835,039.50**	**$ 1,184,731.50**	**$ 259,164.50**	**$ 606,684.50**	**$ 954,204.50**	**$ 1,353,852.50**

UNBUNDLED RATES - PROPOSED

NUG Charge																	
All kWh @ 0.045 ¢/kWh	$ -	$ 1,125.00	$ 3,375.00	$ 5,625.00	$ 8,212.50	$ 1,350.00	$ 4,050.00	$ 6,750.00	$ 9,855.00	$ 1,575.00	$ 4,725.00	$ 7,875.00	$ 11,497.50	$ 1,800.00	$ 5,400.00	$ 9,000.00	$ 13,140.00
Distribution																	
Distribution Charge @ $1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15
All kW @ $1.03/kW	$ 25,750.00	$ 25,750.00	$ 25,750.00	$ 25,750.00	$ 25,750.00	$ 30,900.00	$ 30,900.00	$ 30,900.00	$ 30,900.00	$ 36,050.00	$ 36,050.00	$ 36,050.00	$ 36,050.00	$ 41,200.00	$ 41,200.00	$ 41,200.00	$ 41,200.00
Sub-Total	$ 26,899.15	$ 26,899.15	$ 26,899.15	$ 26,899.15	$ 26,899.15	$ 32,049.15	$ 32,049.15	$ 32,049.15	$ 32,049.15	$ 37,199.15	$ 37,199.15	$ 37,199.15	$ 37,199.15	$ 42,349.15	$ 42,349.15	$ 42,349.15	$ 42,349.15
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ 20,000.00
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @$ 0.973 /kW NSPL	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 38,920.00	$ 38,920.00	$ 38,920.00	$ 38,920.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 550.00	$ 1,650.00	$ 2,750.00	$ 4,015.00	$ 660.00	$ 1,980.00	$ 3,300.00	$ 4,818.00	$ 770.00	$ 2,310.00	$ 3,850.00	$ 5,621.00	$ 880.00	$ 2,640.00	$ 4,400.00	$ 6,424.00
Sub-Total	$ 36,825.00	$ 37,375.00	$ 38,475.00	$ 39,575.00	$ 40,840.00	$ 44,850.00	$ 46,170.00	$ 47,490.00	$ 49,008.00	$ 52,325.00	$ 53,865.00	$ 55,405.00	$ 57,176.00	$ 59,800.00	$ 61,560.00	$ 63,320.00	$ 65,344.00
PTC Charge																	
All kWh @ $ 0.04277 /kWh	$ -	$ 106,925.00	$ 320,775.00	$ 534,625.00	$ 780,552.50	$ 128,310.00	$ 384,930.00	$ 641,550.00	$ 936,663.00	$ 149,695.00	$ 449,085.00	$ 748,475.00	$ 1,092,773.50	$ 171,080.00	$ 513,240.00	$ 855,400.00	$ 1,248,884.00
Sub Total	$ 63,724.15	$ 172,324.15	$ 389,524.15	$ 606,724.15	$ 856,504.15	$ 206,559.15	$ 467,199.15	$ 727,839.15	$ 1,027,575.15	$ 240,794.15	$ 544,874.15	$ 848,954.15	$ 1,198,646.15	$ 275,029.15	$ 622,549.15	$ 970,069.15	$ 1,369,717.15
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 63,724.15**	**$ 172,324.15**	**$ 389,524.15**	**$ 606,724.15**	**$ 856,504.15**	**$ 206,559.15**	**$ 467,199.15**	**$ 727,839.15**	**$ 1,027,575.15**	**$ 240,794.15**	**$ 544,874.15**	**$ 848,954.15**	**$ 1,198,646.15**	**$ 275,029.15**	**$ 622,549.15**	**$ 970,069.15**	**$ 1,369,717.15**
% Increase	**18.65%**	**6.17%**	**2.64%**	**1.68%**	**1.18%**	**6.15%**	**2.63%**	**1.67%**	**1.18%**	**6.13%**	**2.62%**	**1.67%**	**1.17%**	**6.12%**	**2.61%**	**1.66%**	**1.17%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE TP - 8 HOUR ON PEAK TIME OF DAY 115KV DISCOUNT vs RATE TP 115 KV DISCOUNT
With Demands Up to 20,000 KW
At Average Levels of kWh Use

KW Demand																		
Total kW	5,000	5,000	5,000	5,000	5,000	10,000	10,000	10,000	10,000	15,000	15,000	15,000	15,000	20,000	20,000	20,000	20,000	
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730	
REACTIVE DEMAND																		
rkVA	284	284	284	284	284	567	567	567	567	851	851	851	851	1,134	1,134	1,134	1,134	
ENERGY USAGE																		
Monthly Energy Usage	0	500,000	1,500,000	2,500,000	3,650,000	1,000,000	3,000,000	5,000,000	7,300,000	1,500,000	4,500,000	7,500,000	10,950,000	2,000,000	6,000,000	10,000,000	14,600,000	
Total Energy Usage	0	500,000	1,500,000	2,500,000	3,650,000	1,000,000	3,000,000	5,000,000	7,300,000	1,500,000	4,500,000	7,500,000	10,950,000	2,000,000	6,000,000	10,000,000	14,600,000	

UNBUNDLED RATES - CURRENT

NUG Charge																		
All kWh @ 0.045 ¢/kWh	$ -	$ 225.00	$ 675.00	$ 1,125.00	$ 1,642.50	$ 450.00	$ 1,350.00	$ 2,250.00	$ 3,285.00	$ 675.00	$ 2,025.00	$ 3,375.00	$ 4,927.50	$ 900.00	$ 2,700.00	$ 4,500.00	$ 6,570.00	
Distribution																		
Distribution Charge @ $882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	
All kW @ $0.37/kW	$ 1,850.00	$ 1,850.00	$ 1,850.00	$ 1,850.00	$ 1,850.00	$ 3,700.00	$ 3,700.00	$ 3,700.00	$ 3,700.00	$ 5,550.00	$ 5,550.00	$ 5,550.00	$ 5,550.00	$ 7,400.00	$ 7,400.00	$ 7,400.00	$ 7,400.00	
Sub-Total	$ 2,732.16	$ 2,732.16	$ 2,732.16	$ 2,732.16	$ 2,732.16	$ 4,582.16	$ 4,582.16	$ 4,582.16	$ 4,582.16	$ 6,432.16	$ 6,432.16	$ 6,432.16	$ 6,432.16	$ 8,282.16	$ 8,282.16	$ 8,282.16	$ 8,282.16	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	
Smart Meter Charge @ $2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	
Default Service Support Charge @ $ 0.973 /kW NSPL	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 110.00	$ 330.00	$ 550.00	$ 803.00	$ 220.00	$ 660.00	$ 1,100.00	$ 1,606.00	$ 330.00	$ 990.00	$ 1,650.00	$ 2,409.00	$ 440.00	$ 1,320.00	$ 2,200.00	$ 3,212.00	
Sub-Total	$ 7,367.34	$ 7,477.34	$ 7,697.34	$ 7,917.34	$ 8,170.34	$ 14,952.34	$ 15,392.34	$ 15,832.34	$ 16,338.34	$ 22,427.34	$ 23,087.34	$ 23,747.34	$ 24,506.34	$ 29,902.34	$ 30,782.34	$ 31,662.34	$ 32,674.34	
PTC Charge																		
All kWh @ $ 0.04277 /kWh	$ -	$ 21,385.00	$ 64,155.00	$ 106,925.00	$ 156,110.50	$ 42,770.00	$ 128,310.00	$ 213,850.00	$ 312,221.00	$ 64,155.00	$ 192,465.00	$ 320,775.00	$ 468,331.50	$ 85,540.00	$ 256,620.00	$ 427,700.00	$ 624,442.00	
Sub Total	$ 10,099.50	$ 31,819.50	$ 75,259.50	$ 118,699.50	$ 168,655.50	$ 62,754.50	$ 149,634.50	$ 236,514.50	$ 336,426.50	$ 93,689.50	$ 224,009.50	$ 354,329.50	$ 504,197.50	$ 124,624.50	$ 298,384.50	$ 472,144.50	$ 671,968.50	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 10,099.50**	**$ 31,819.50**	**$ 75,259.50**	**$ 118,699.50**	**$ 168,655.50**	**$ 62,754.50**	**$ 149,634.50**	**$ 236,514.50**	**$ 336,426.50**	**$ 93,689.50**	**$ 224,009.50**	**$ 354,329.50**	**$ 504,197.50**	**$ 124,624.50**	**$ 298,384.50**	**$ 472,144.50**	**$ 671,968.50**	

UNBUNDLED RATES - PROPOSED

NUG Charge																		
All kWh @ 0.045 ¢/kWh	$ -	$ 225.00	$ 675.00	$ 1,125.00	$ 1,642.50	$ 450.00	$ 1,350.00	$ 2,250.00	$ 3,285.00	$ 675.00	$ 2,025.00	$ 3,375.00	$ 4,927.50	$ 900.00	$ 2,700.00	$ 4,500.00	$ 6,570.00	
Distribution																		
Distribution Charge @ $1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	
All kW @ $0.72/kW	$ 3,600.00	$ 3,600.00	$ 3,600.00	$ 3,600.00	$ 3,600.00	$ 7,200.00	$ 7,200.00	$ 7,200.00	$ 7,200.00	$ 10,800.00	$ 10,800.00	$ 10,800.00	$ 10,800.00	$ 14,400.00	$ 14,400.00	$ 14,400.00	$ 14,400.00	
Sub-Total	$ 4,749.15	$ 4,749.15	$ 4,749.15	$ 4,749.15	$ 4,749.15	$ 8,349.15	$ 8,349.15	$ 8,349.15	$ 8,349.15	$ 11,949.15	$ 11,949.15	$ 11,949.15	$ 11,949.15	$ 15,549.15	$ 15,549.15	$ 15,549.15	$ 15,549.15	
Riders																		
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 2,500.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 5,000.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 7,500.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Default Service Support Charge @$ 0.973 /kW NSPL	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 4,865.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 9,730.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 14,595.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	$ 19,460.00	
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 110.00	$ 330.00	$ 550.00	$ 803.00	$ 220.00	$ 660.00	$ 1,100.00	$ 1,606.00	$ 330.00	$ 990.00	$ 1,650.00	$ 2,409.00	$ 440.00	$ 1,320.00	$ 2,200.00	$ 3,212.00	
Sub-Total	$ 7,365.00	$ 7,475.00	$ 7,695.00	$ 7,915.00	$ 8,168.00	$ 14,950.00	$ 15,390.00	$ 15,830.00	$ 16,336.00	$ 22,425.00	$ 23,085.00	$ 23,745.00	$ 24,504.00	$ 29,900.00	$ 30,780.00	$ 31,660.00	$ 32,672.00	
PTC Charge																		
All kWh @ $ 0.04277 /kWh	$ -	$ 21,385.00	$ 64,155.00	$ 106,925.00	$ 156,110.50	$ 42,770.00	$ 128,310.00	$ 213,850.00	$ 312,221.00	$ 64,155.00	$ 192,465.00	$ 320,775.00	$ 468,331.50	$ 85,540.00	$ 256,620.00	$ 427,700.00	$ 624,442.00	
Sub Total	$ 12,114.15	$ 33,834.15	$ 77,274.15	$ 120,714.15	$ 170,670.15	$ 66,519.15	$ 153,399.15	$ 240,279.15	$ 340,191.15	$ 99,204.15	$ 229,524.15	$ 359,844.15	$ 509,712.15	$ 131,889.15	$ 305,649.15	$ 479,409.15	$ 679,233.15	
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Bill	**$ 12,114.15**	**$ 33,834.15**	**$ 77,274.15**	**$ 120,714.15**	**$ 170,670.15**	**$ 66,519.15**	**$ 153,399.15**	**$ 240,279.15**	**$ 340,191.15**	**$ 99,204.15**	**$ 229,524.15**	**$ 359,844.15**	**$ 509,712.15**	**$ 131,889.15**	**$ 305,649.15**	**$ 479,409.15**	**$ 679,233.15**	
% Increase	**19.95%**	**6.33%**	**2.68%**	**1.70%**	**1.19%**	**6.00%**	**2.52%**	**1.59%**	**1.12%**	**5.89%**	**2.46%**	**1.56%**	**1.09%**	**5.83%**	**2.43%**	**1.54%**	**1.08%**	

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE TP - 8 HOUR ON PEAK TIME OF DAY 115KV DISCOUNT vs RATE TP 115 KV DISCOUNT
With Demands Over 20,000 KW
At Average Levels of kWh Use

KW Demand																	
Total kW	25,000	25,000	25,000	25,000	25,000	30,000	30,000	30,000	30,000	35,000	35,000	35,000	35,000	40,000	40,000	40,000	40,000
Hrs Use	0	100	300	500	730	100	300	500	730	100	300	500	730	100	300	500	730
REACTIVE DEMAND																	
rkVA	1,418	1,418	1,418	1,418	1,418	1,701	1,701	1,701	1,701	1,985	1,985	1,985	1,985	2,268	2,268	2,268	2,268
ENERGY USAGE																	
Monthly Energy Usage	0	2,500,000	7,500,000	12,500,000	18,250,000	3,000,000	9,000,000	15,000,000	21,900,000	3,500,000	10,500,000	17,500,000	25,550,000	4,000,000	12,000,000	20,000,000	29,200,000
Total Energy Usage	0	2,500,000	7,500,000	12,500,000	18,250,000	3,000,000	9,000,000	15,000,000	21,900,000	3,500,000	10,500,000	17,500,000	25,550,000	4,000,000	12,000,000	20,000,000	29,200,000

UNBUNDLED RATES - CURRENT

NUG Charge																	
All kWh @ 0.045 ¢/kWh	$ -	$ 1,125.00	$ 3,375.00	$ 5,625.00	$ 8,212.50	$ 1,350.00	$ 4,050.00	$ 6,750.00	$ 9,855.00	$ 1,575.00	$ 4,725.00	$ 7,875.00	$ 11,497.50	$ 1,800.00	$ 5,400.00	$ 9,000.00	$ 13,140.00
Distribution																	
Distribution Charge @ $882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16	$ 882.16
All kW @ $0.37/kW	$ 9,250.00	$ 9,250.00	$ 9,250.00	$ 9,250.00	$ 9,250.00	$ 11,100.00	$ 11,100.00	$ 11,100.00	$ 11,100.00	$ 12,950.00	$ 12,950.00	$ 12,950.00	$ 12,950.00	$ 14,800.00	$ 14,800.00	$ 14,800.00	$ 14,800.00
Sub-Total	$ 10,132.16	$ 10,132.16	$ 10,132.16	$ 10,132.16	$ 10,132.16	$ 11,982.16	$ 11,982.16	$ 11,982.16	$ 11,982.16	$ 13,832.16	$ 13,832.16	$ 13,832.16	$ 13,832.16	$ 15,682.16	$ 15,682.16	$ 15,682.16	$ 15,682.16
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ 20,000.00
Smart Meter Charge @ $2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34
Default Service Support Charge @ $ 0.973 /kW NSPL	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 38,920.00	$ 38,920.00	$ 38,920.00	$ 38,920.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 550.00	$ 1,650.00	$ 2,750.00	$ 4,015.00	$ 660.00	$ 1,980.00	$ 3,300.00	$ 4,818.00	$ 770.00	$ 2,310.00	$ 3,850.00	$ 5,621.00	$ 880.00	$ 2,640.00	$ 4,400.00	$ 6,424.00
Sub-Total	$ 36,827.34	$ 37,377.34	$ 38,477.34	$ 39,577.34	$ 40,842.34	$ 44,852.34	$ 46,172.34	$ 47,492.34	$ 49,010.34	$ 52,327.34	$ 53,867.34	$ 55,407.34	$ 57,178.34	$ 59,802.34	$ 61,562.34	$ 63,322.34	$ 65,346.34
PTC Charge																	
All kWh @ $ 0.04277 /kWh	$ -	$ 106,925.00	$ 320,775.00	$ 534,625.00	$ 780,552.50	$ 128,310.00	$ 384,930.00	$ 641,550.00	$ 936,663.00	$ 149,695.00	$ 449,085.00	$ 748,475.00	$ 1,092,773.50	$ 171,080.00	$ 513,240.00	$ 855,400.00	$ 1,248,884.00
Sub Total	$ 46,959.50	$ 155,559.50	$ 372,759.50	$ 589,959.50	$ 839,739.50	$ 186,494.50	$ 447,134.50	$ 707,774.50	$ 1,007,510.50	$ 217,429.50	$ 521,509.50	$ 825,589.50	$ 1,175,281.50	$ 248,364.50	$ 595,884.50	$ 943,404.50	$ 1,343,052.50
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 46,959.50**	**$ 155,559.50**	**$ 372,759.50**	**$ 589,959.50**	**$ 839,739.50**	**$ 186,494.50**	**$ 447,134.50**	**$ 707,774.50**	**$ 1,007,510.50**	**$ 217,429.50**	**$ 521,509.50**	**$ 825,589.50**	**$ 1,175,281.50**	**$ 248,364.50**	**$ 595,884.50**	**$ 943,404.50**	**$ 1,343,052.50**

UNBUNDLED RATES - PROPOSED

NUG Charge																	
All kWh @ 0.045 ¢/kWh	$ -	$ 1,125.00	$ 3,375.00	$ 5,625.00	$ 8,212.50	$ 1,350.00	$ 4,050.00	$ 6,750.00	$ 9,855.00	$ 1,575.00	$ 4,725.00	$ 7,875.00	$ 11,497.50	$ 1,800.00	$ 5,400.00	$ 9,000.00	$ 13,140.00
Distribution																	
Distribution Charge @ $1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15	$ 1,149.15
All kW @ $0.72/kW	$ 18,000.00	$ 18,000.00	$ 18,000.00	$ 18,000.00	$ 18,000.00	$ 21,600.00	$ 21,600.00	$ 21,600.00	$ 21,600.00	$ 25,200.00	$ 25,200.00	$ 25,200.00	$ 25,200.00	$ 28,800.00	$ 28,800.00	$ 28,800.00	$ 28,800.00
Sub-Total	$ 19,149.15	$ 19,149.15	$ 19,149.15	$ 19,149.15	$ 19,149.15	$ 22,749.15	$ 22,749.15	$ 22,749.15	$ 22,749.15	$ 26,349.15	$ 26,349.15	$ 26,349.15	$ 26,349.15	$ 29,949.15	$ 29,949.15	$ 29,949.15	$ 29,949.15
Riders																	
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ $ 0.00 /kW PLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ $ 0.50 /kW PLC	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 17,500.00	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ 20,000.00
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @$ 0.973 /kW NSPL	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 24,325.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 29,190.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 34,055.00	$ 38,920.00	$ 38,920.00	$ 38,920.00	$ 38,920.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 550.00	$ 1,650.00	$ 2,750.00	$ 4,015.00	$ 660.00	$ 1,980.00	$ 3,300.00	$ 4,818.00	$ 770.00	$ 2,310.00	$ 3,850.00	$ 5,621.00	$ 880.00	$ 2,640.00	$ 4,400.00	$ 6,424.00
Sub-Total	$ 36,825.00	$ 37,375.00	$ 38,475.00	$ 39,575.00	$ 40,840.00	$ 44,850.00	$ 46,170.00	$ 47,490.00	$ 49,008.00	$ 52,325.00	$ 53,865.00	$ 55,405.00	$ 57,176.00	$ 59,800.00	$ 61,560.00	$ 63,320.00	$ 65,344.00
PTC Charge																	
All kWh @ $ 0.04277 /kWh	$ -	$ 106,925.00	$ 320,775.00	$ 534,625.00	$ 780,552.50	$ 128,310.00	$ 384,930.00	$ 641,550.00	$ 936,663.00	$ 149,695.00	$ 449,085.00	$ 748,475.00	$ 1,092,773.50	$ 171,080.00	$ 513,240.00	$ 855,400.00	$ 1,248,884.00
Sub Total	$ 55,974.15	$ 164,574.15	$ 381,774.15	$ 598,974.15	$ 848,754.15	$ 197,259.15	$ 457,899.15	$ 718,539.15	$ 1,018,275.15	$ 229,944.15	$ 534,024.15	$ 838,104.15	$ 1,187,796.15	$ 262,629.15	$ 610,149.15	$ 957,669.15	$ 1,357,317.15
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 55,974.15**	**$ 164,574.15**	**$ 381,774.15**	**$ 598,974.15**	**$ 848,754.15**	**$ 197,259.15**	**$ 457,899.15**	**$ 718,539.15**	**$ 1,018,275.15**	**$ 229,944.15**	**$ 534,024.15**	**$ 838,104.15**	**$ 1,187,796.15**	**$ 262,629.15**	**$ 610,149.15**	**$ 957,669.15**	**$ 1,357,317.15**
% Increase	**19.20%**	**5.79%**	**2.42%**	**1.53%**	**1.07%**	**5.77%**	**2.41%**	**1.52%**	**1.07%**	**5.76%**	**2.40%**	**1.52%**	**1.06%**	**5.74%**	**2.39%**	**1.51%**	**1.06%**

METROPOLITAN EDISON COMPANY
COMPARISON BETWEEN PRESENT AND PROPOSED RATES
RATE MS

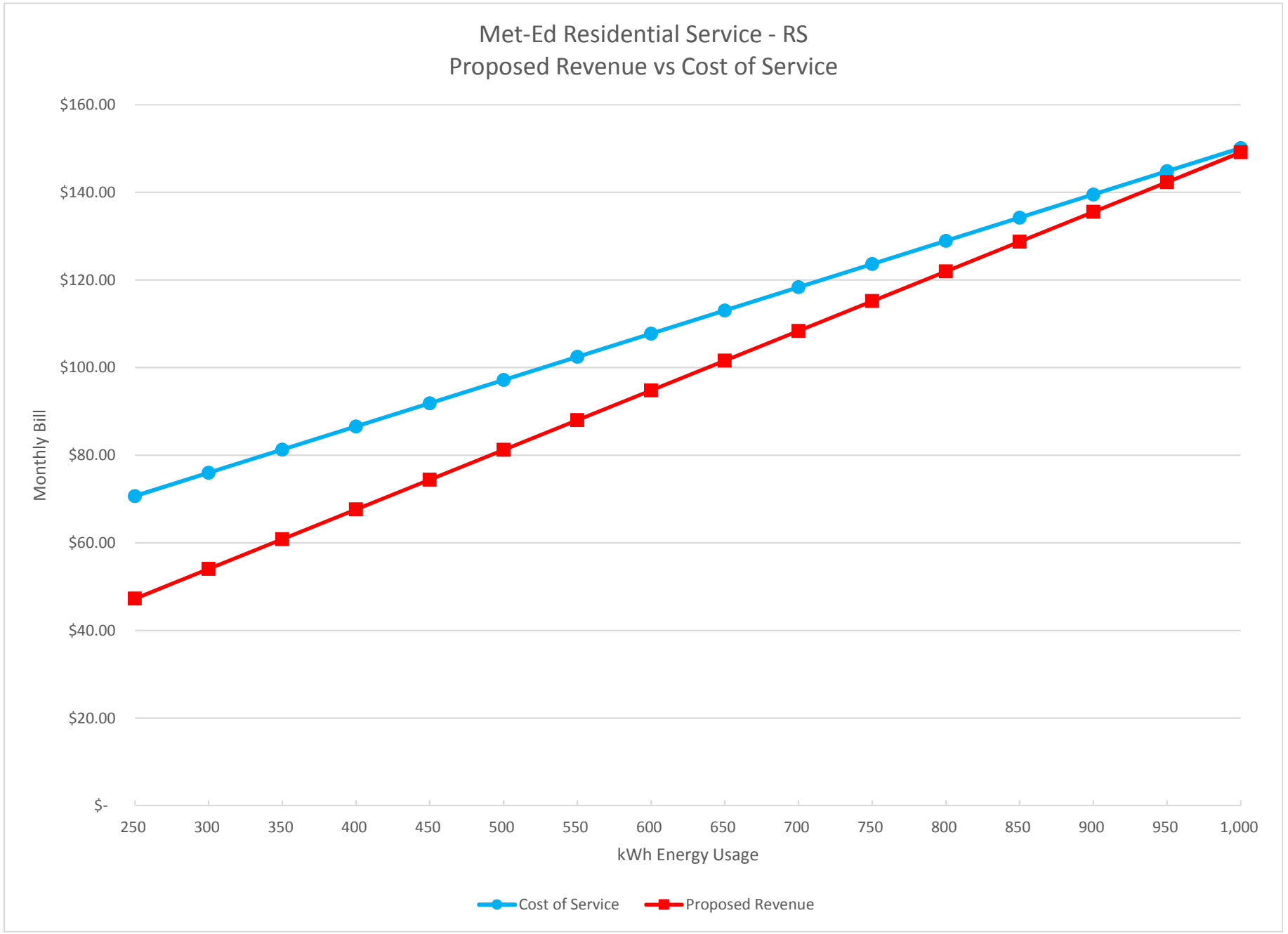
ENERGY USAGE																
All kWh	0	100	200	400	600	1,000	1,500	2,000	3,000	5,000	7,000	9,000	12,000	15,000	20,000	25,000
Total Energy Usage	0	100	200	400	600	1,000	1,500	2,000	3,000	5,000	7,000	9,000	12,000	15,000	20,000	25,000

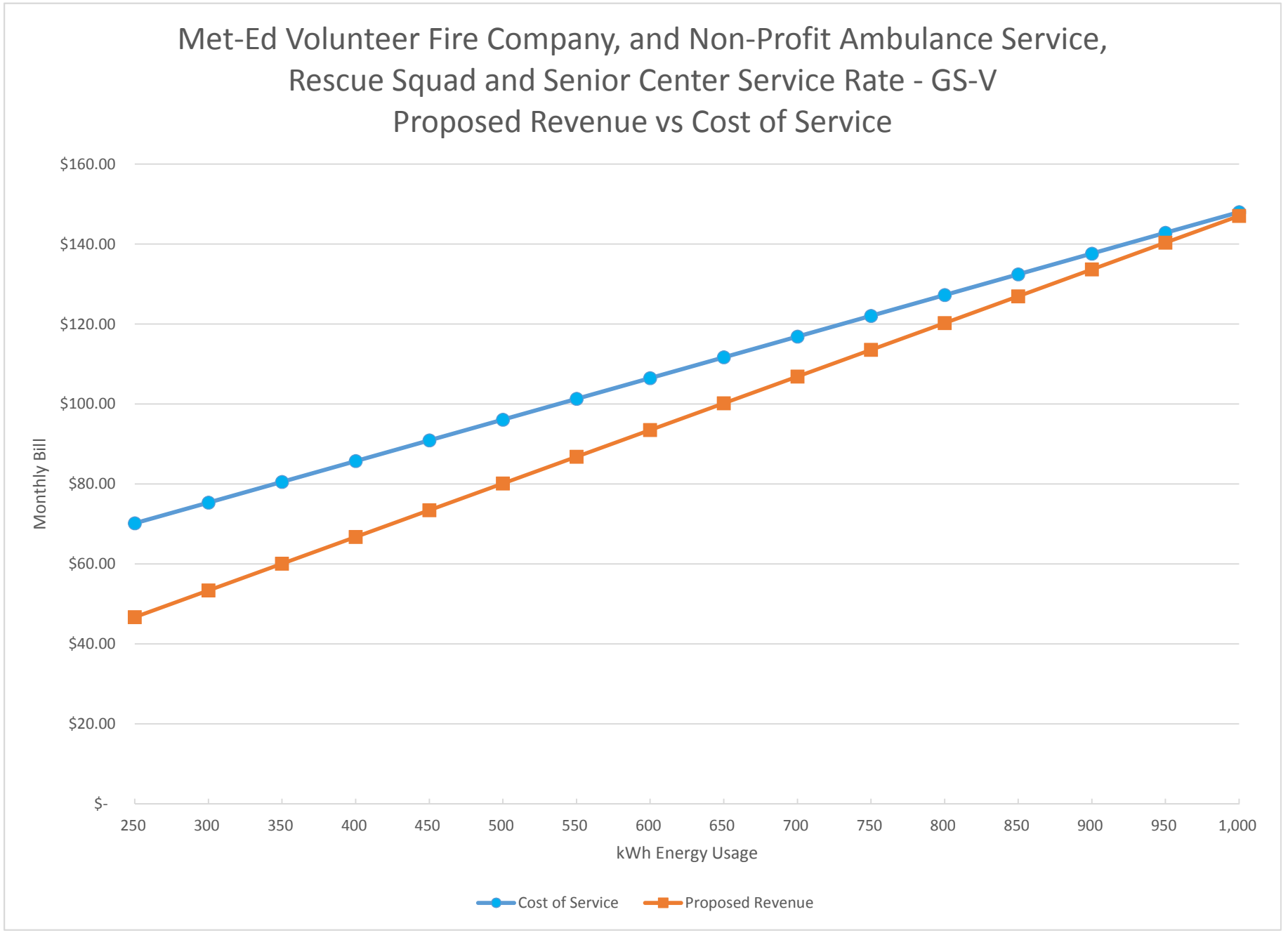
UNBUNDLED RATES - CURRENT

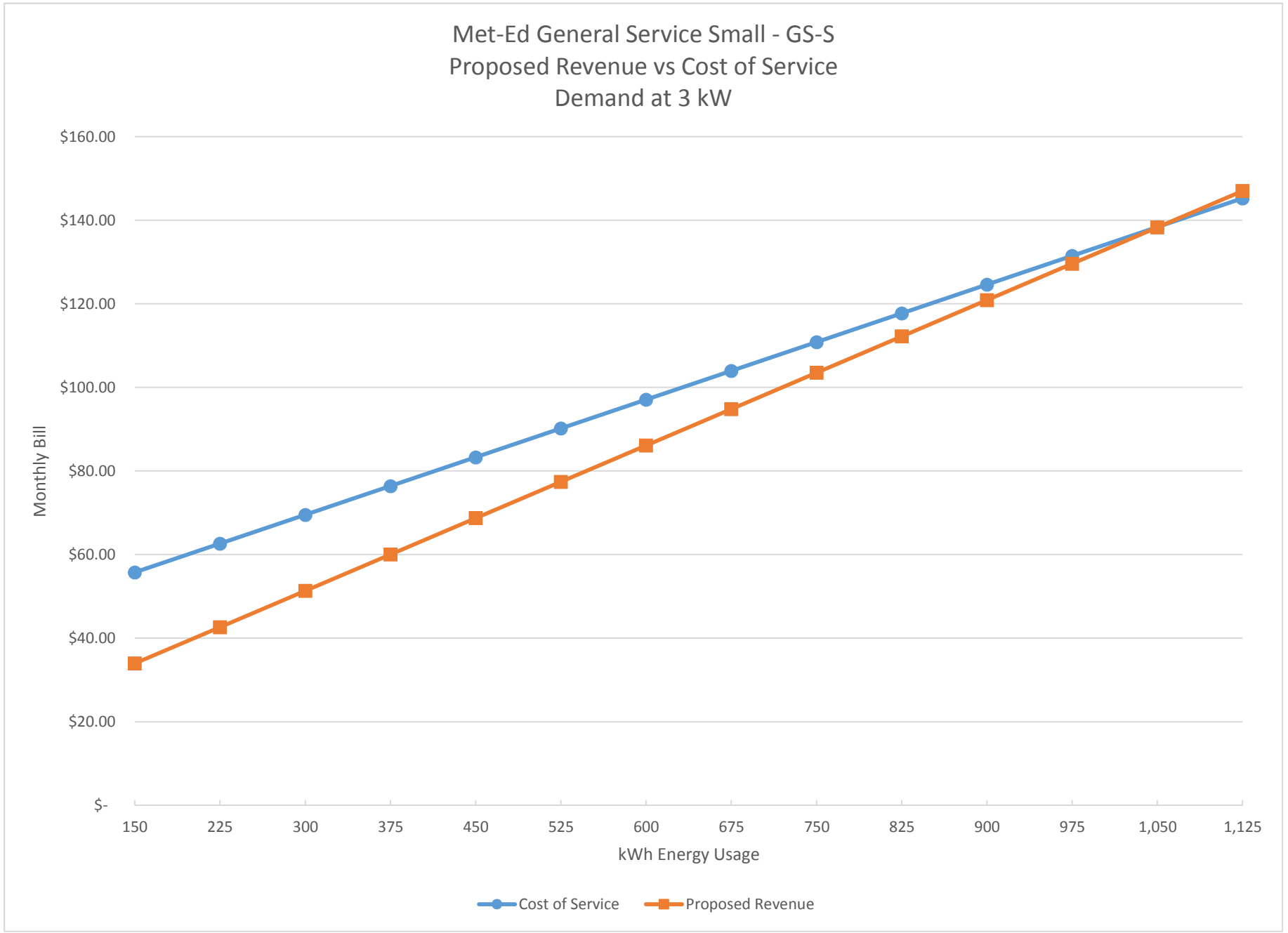
NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (0.00)	$ (0.00)	$ (0.01)	$ (0.01)	$ (0.02)	$ (0.03)	$ (0.04)	$ (0.06)	$ (0.10)	$ (0.14)	$ (0.18)	$ (0.24)	$ (0.30)	$ (0.40)	$ (0.50)
Distribution																
Distribution Charge @ $24.82	$ 24.82	$ 24.82	$ 24.82	$ 24.82	$ 24.82	$ 24.82	$ 24.82	$ 24.82	$ 24.82	$ 24.82	$ 24.82	$ 24.82	$ 24.82	$ 24.82	$ 24.82	$ 24.82
All kWh @ 2.674 ¢/kWh	$ -	$ 2.67	$ 5.35	$ 10.70	$ 16.04	$ 26.74	$ 40.11	$ 53.48	$ 80.22	$ 133.70	$ 187.18	$ 240.66	$ 320.88	$ 401.10	$ 534.80	$ 668.50
Sub-Total	$ 24.82	$ 27.49	$ 30.17	$ 35.52	$ 40.86	$ 51.56	$ 64.93	$ 78.30	$ 105.04	$ 158.52	$ 212.00	$ 265.48	$ 345.70	$ 425.92	$ 559.62	$ 693.32
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.103 ¢/kWh	$ -	$ 0.10	$ 0.21	$ 0.41	$ 0.62	$ 1.03	$ 1.55	$ 2.06	$ 3.09	$ 5.15	$ 7.21	$ 9.27	$ 12.36	$ 15.45	$ 20.60	$ 25.75
Smart Meter Charge @ $3.32	$ 3.32	$3.32	$ 3.32	$ 3.32	$ 3.32	$ 3.32	$ 3.32	$ 3.32	$ 3.32	$ 3.32	$ 3.32	$ 3.32	$ 3.32	$ 3.32	$ 3.32	$ 3.32
Default Service Support Charge @ 0.236 ¢/kWh	$ -	$ 0.24	$ 0.47	$ 0.94	$ 1.42	$ 2.36	$ 3.54	$ 4.72	$ 7.08	$ 11.80	$ 16.52	$ 21.24	$ 28.32	$ 35.40	$ 47.20	$ 59.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.02	$ 0.04	$ 0.09	$ 0.13	$ 0.22	$ 0.33	$ 0.44	$ 0.66	$ 1.10	$ 1.54	$ 1.98	$ 2.64	$ 3.30	$ 4.40	$ 5.50
Sub-Total	$ 3.32	$ 3.68	$ 4.04	$ 4.76	$ 5.49	$ 6.93	$ 8.74	$ 10.54	$ 14.15	$ 21.37	$ 28.59	$ 35.81	$ 46.64	$ 57.47	$ 75.52	$ 93.57
PTC Charge																
All kWh @ $ 0.08048 /kWh	$ -	$ 8.05	$ 16.10	$ 32.19	$ 48.29	$ 80.48	$ 120.72	$ 160.96	$ 241.44	$ 402.40	$ 563.36	$ 724.32	$ 965.76	$ 1,207.20	$ 1,609.60	$ 2,012.00
Sub Total	$ 28.14	$ 39.22	$ 50.30	$ 72.46	$ 94.63	$ 138.95	$ 194.36	$ 249.76	$ 360.57	$ 582.19	$ 803.81	$ 1,025.43	$ 1,357.86	$ 1,690.29	$ 2,244.34	$ 2,798.39
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 28.14**	**$ 39.22**	**$ 50.30**	**$ 72.46**	**$ 94.63**	**$ 138.95**	**$ 194.36**	**$ 249.76**	**$ 360.57**	**$ 582.19**	**$ 803.81**	**$ 1,025.43**	**$ 1,357.86**	**$ 1,690.29**	**$ 2,244.34**	**$ 2,798.39**

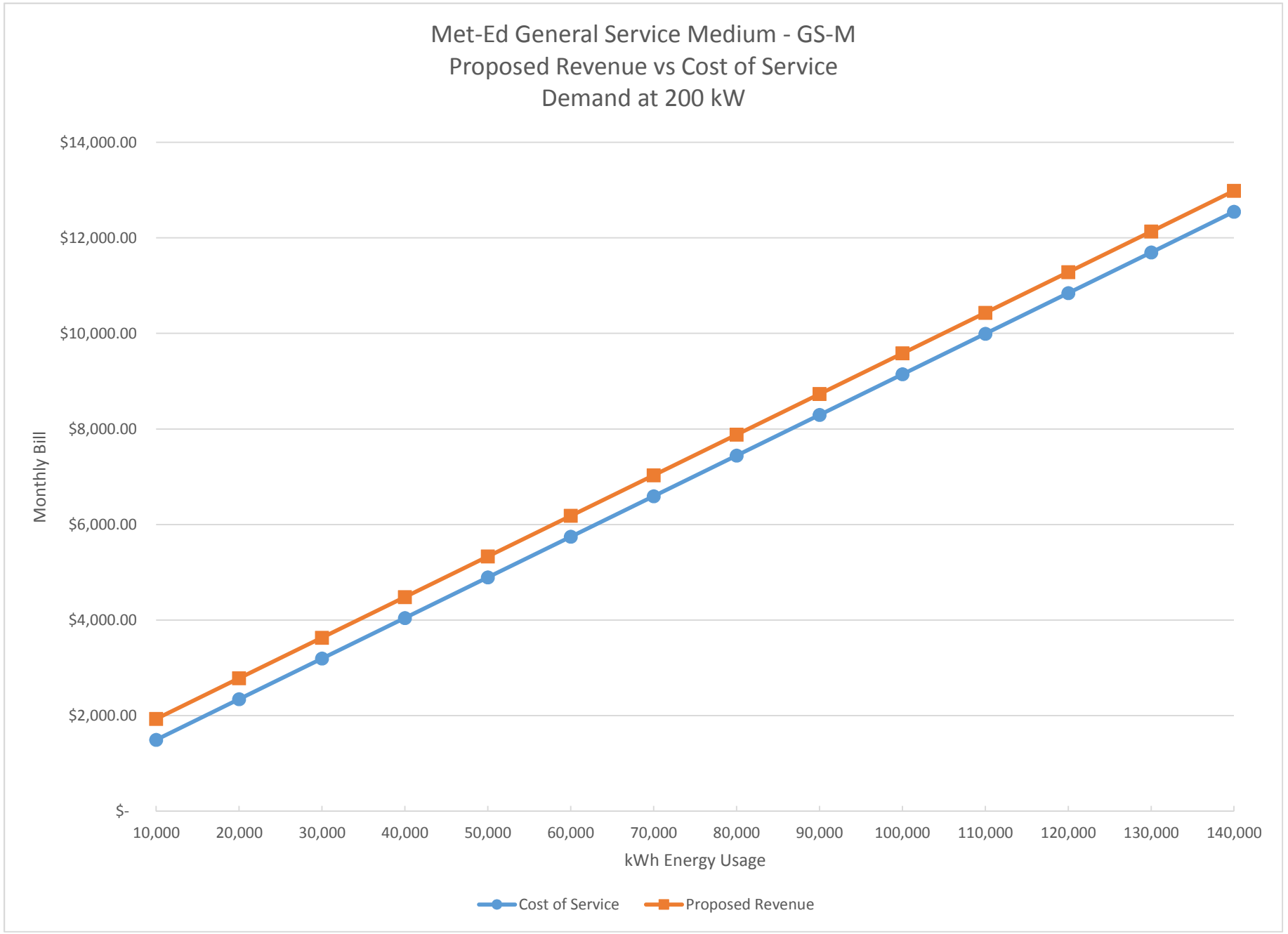
UNBUNDLED RATES - PROPOSED

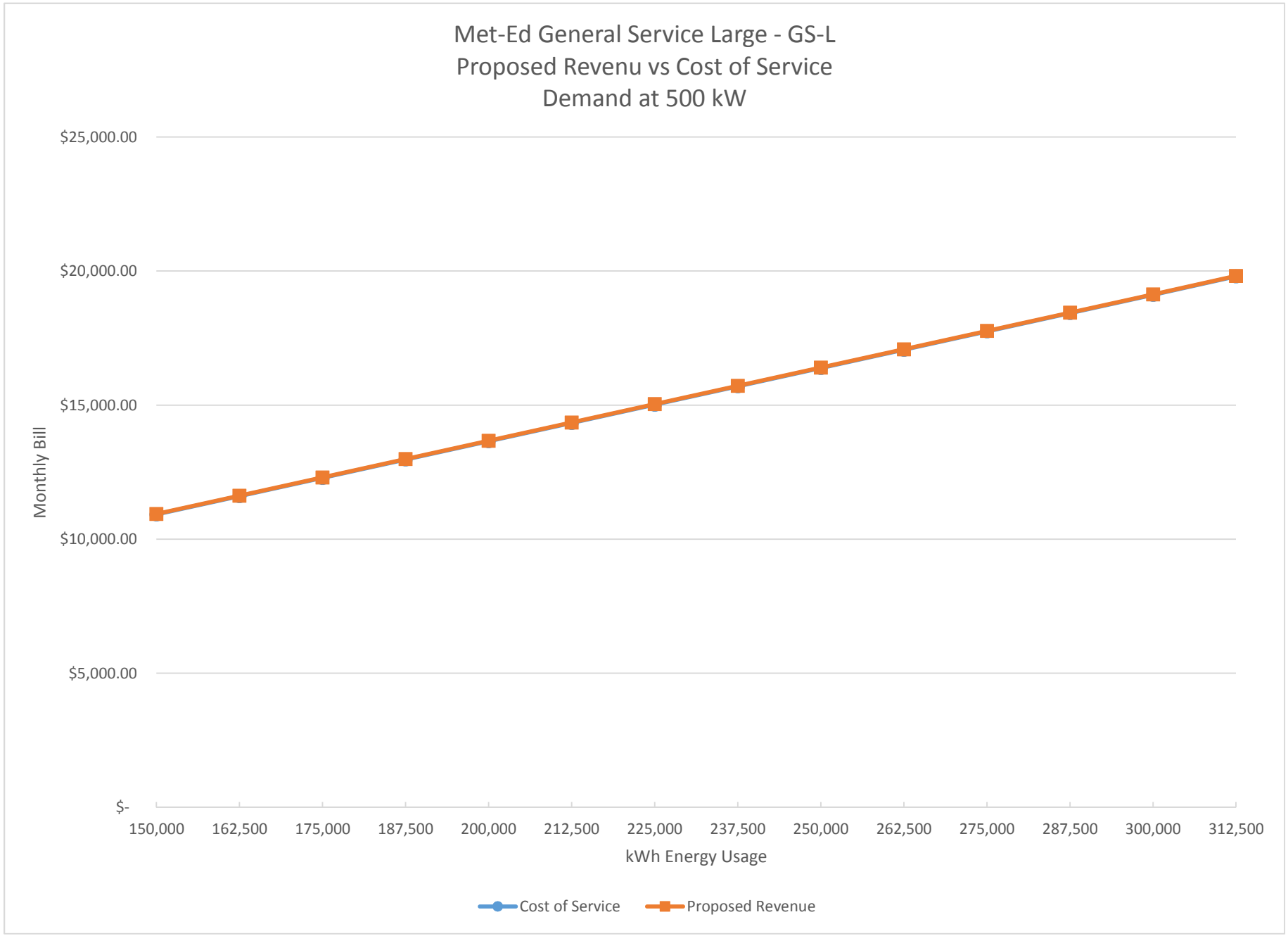
NUG Charge																
All kWh @ -0.002 ¢/kWh	$ -	$ (0.00)	$ (0.00)	$ (0.01)	$ (0.01)	$ (0.02)	$ (0.03)	$ (0.04)	$ (0.06)	$ (0.10)	$ (0.14)	$ (0.18)	$ (0.24)	$ (0.30)	$ (0.40)	$ (0.50)
Distribution																
Distribution Charge @ $34.34	$ 34.34	$ 34.34	$ 34.34	$ 34.34	$ 34.34	$ 34.34	$ 34.34	$ 34.34	$ 34.34	$ 34.34	$ 34.34	$ 34.34	$ 34.34	$ 34.34	$ 34.34	$ 34.34
All kWh @ 4.488 ¢/kWh	$ -	$ 4.49	$ 8.98	$ 17.95	$ 26.93	$ 44.88	$ 67.32	$ 89.76	$ 134.64	$ 224.40	$ 314.16	$ 403.92	$ 538.56	$ 673.20	$ 897.60	$ 1,122.00
Sub-Total	$ 34.34	$ 38.83	$ 43.32	$ 52.29	$ 61.27	$ 79.22	$ 101.66	$ 124.10	$ 168.98	$ 258.74	$ 348.50	$ 438.26	$ 572.90	$ 707.54	$ 931.94	$ 1,156.34
Riders																
Consumer Education Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Efficiency Charge @ 0.000 ¢/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Phase II Energy Efficiency Charge @ 0.103 ¢/kWh	$ -	$ 0.10	$ 0.21	$ 0.41	$ 0.62	$ 1.03	$ 1.55	$ 2.06	$ 3.09	$ 5.15	$ 7.21	$ 9.27	$ 12.36	$ 15.45	$ 20.60	$ 25.75
Smart Meter Charge @ $0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Default Service Support Charge @ 0.236 ¢/kWh	$ -	$ 0.24	$ 0.47	$ 0.94	$ 1.42	$ 2.36	$ 3.54	$ 4.72	$ 7.08	$ 11.80	$ 16.52	$ 21.24	$ 28.32	$ 35.40	$ 47.20	$ 59.00
Solar Photovoltaic Requirements Charge @ 0.022 ¢/kWh	$ -	$ 0.02	$ 0.04	$ 0.09	$ 0.13	$ 0.22	$ 0.33	$ 0.44	$ 0.66	$ 1.10	$ 1.54	$ 1.98	$ 2.64	$ 3.30	$ 4.40	$ 5.50
Sub-Total	$ -	$ 0.36	$ 0.72	$ 1.44	$ 2.17	$ 3.61	$ 5.42	$ 7.22	$ 10.83	$ 18.05	$ 25.27	$ 32.49	$ 43.32	$ 54.15	$ 72.20	$ 90.25
PTC Charge																
All kWh @ $ 0.08048 /kWh	$ -	$ 8.05	$ 16.10	$ 32.19	$ 48.29	$ 80.48	$ 120.72	$ 160.96	$ 241.44	$ 402.40	$ 563.36	$ 724.32	$ 965.76	$ 1,207.20	$ 1,609.60	$ 2,012.00
Sub Total	$ 34.34	$ 47.24	$ 60.13	$ 85.92	$ 111.71	$ 163.29	$ 227.77	$ 292.24	$ 421.19	$ 679.09	$ 936.99	$ 1,194.89	$ 1,581.74	$ 1,968.59	$ 2,613.34	$ 3,258.09
STAS @ 0.00 %	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Bill	**$ 34.34**	**$ 47.24**	**$ 60.13**	**$ 85.92**	**$ 111.71**	**$ 163.29**	**$ 227.77**	**$ 292.24**	**$ 421.19**	**$ 679.09**	**$ 936.99**	**$ 1,194.89**	**$ 1,581.74**	**$ 1,968.59**	**$ 2,613.34**	**$ 3,258.09**
% Increase	**22.03%**	**20.43%**	**19.54%**	**18.57%**	**18.05%**	**17.52%**	**17.19%**	**17.01%**	**16.81%**	**16.64%**	**16.57%**	**16.53%**	**16.49%**	**16.46%**	**16.44%**	**16.43%**

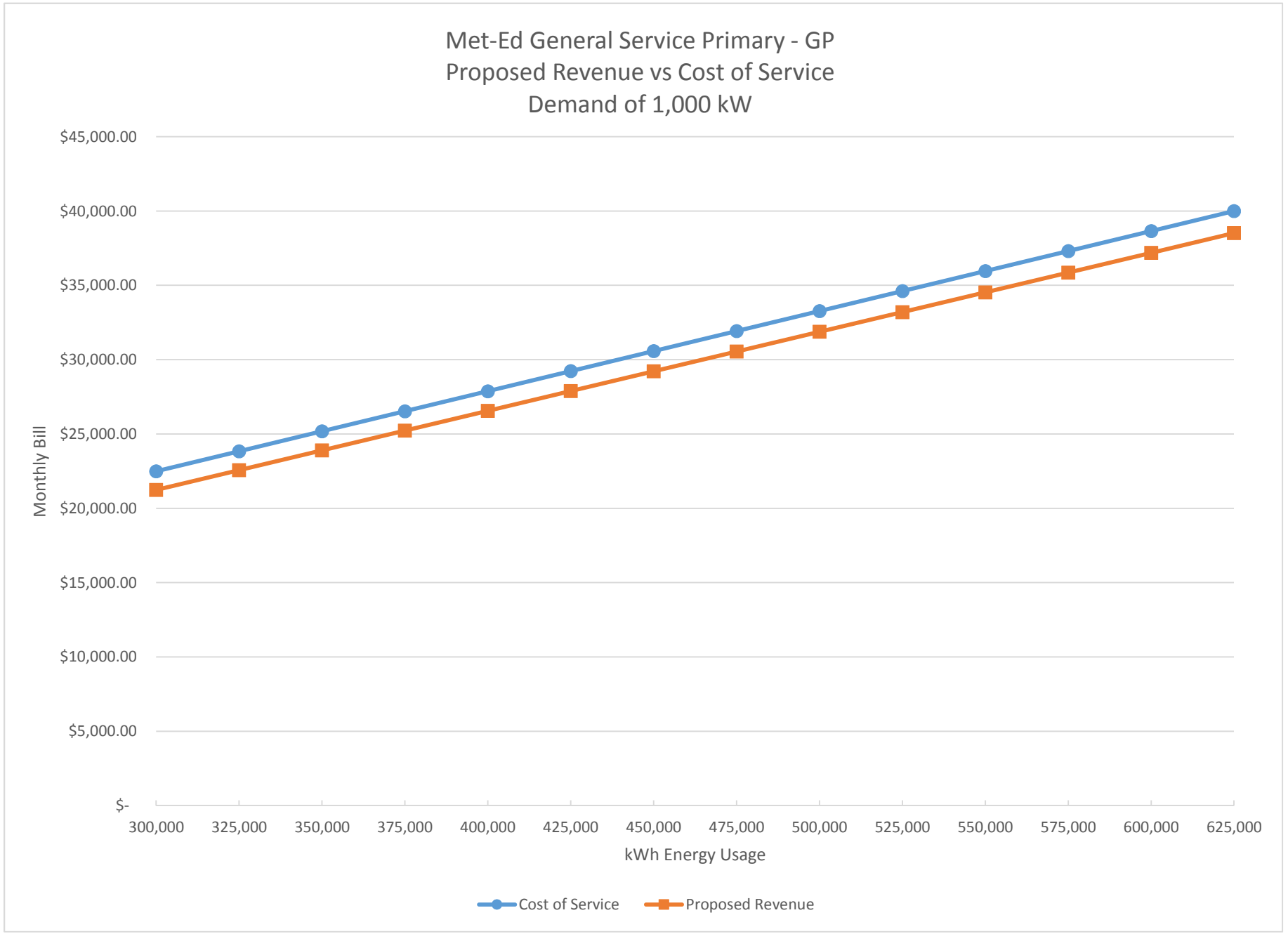

Met-Ed Residential Service - RS
Proposed Revenue vs Cost of Service
$160.00
$140.00
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$-
Monthly Bill
250
300
350
400
450
500
550
600
650
700
750
800
850
900
950
1,000
kWh Energy Usage
Cost of Service
Proposed Revenue

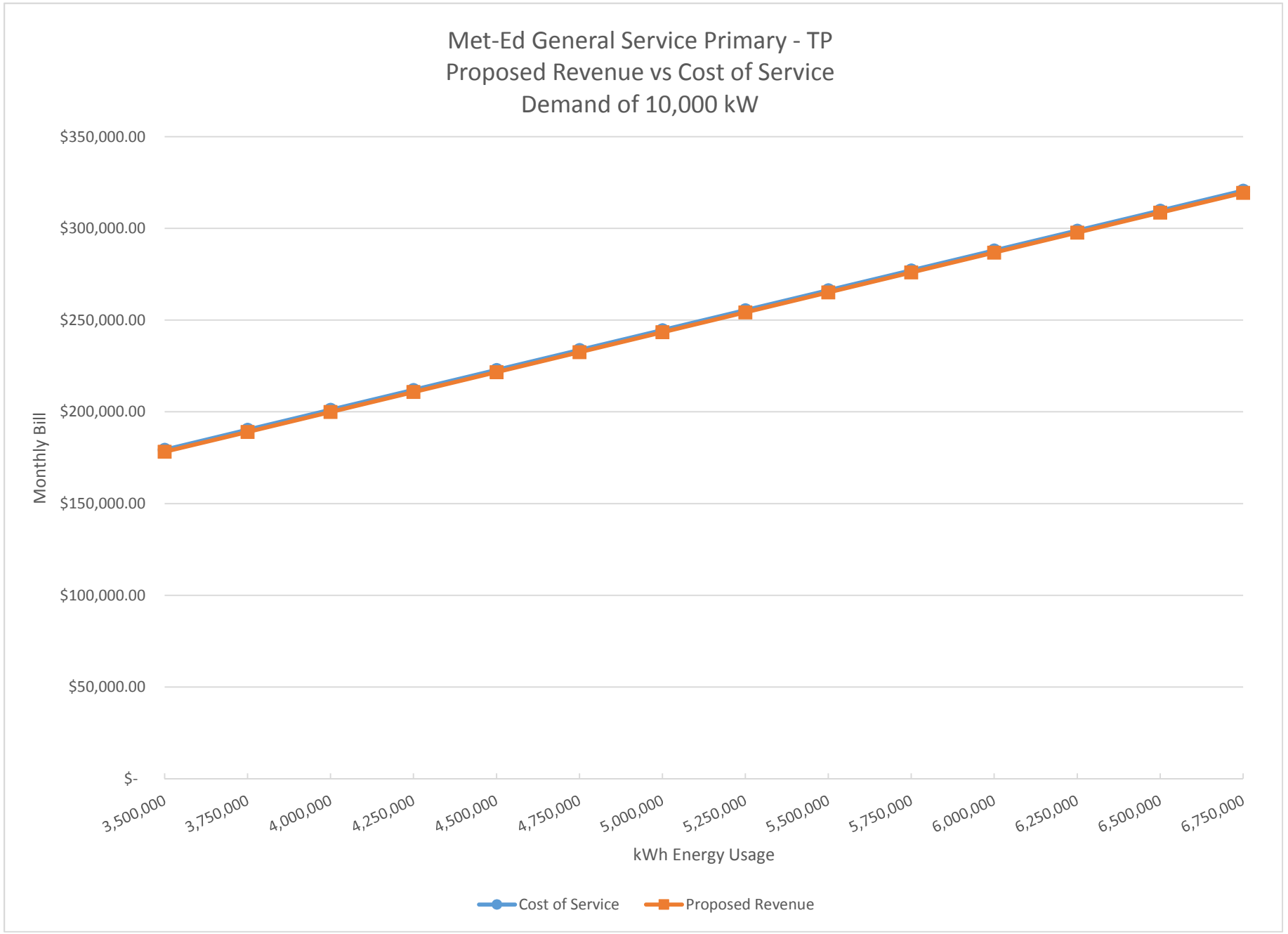

Met-Ed Volunteer Fire Company, and Non-Profit Ambulance Service,
Rescue Squad and Senior Center Service Rate - GS-V
Proposed Revenue vs Cost of Service
$160.00
$140.00
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$-
Monthly Bill
250
300
350
400
450
500
550
600
650
700
750
800
850
900
950
1,000
kWh Energy Usage
Cost of Service
Proposed Revenue


Met-Ed General Service Small - GS-S
Proposed Revenue vs Cost of Service
Demand at 3 kW
$160.00
$140.00
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$-
Monthly Bill
150
225
300
375
450
525
600
675
750
825
900
975
1,050
1,125
kWh Energy Usage
Cost of Service
Proposed Revenue


Met-Ed General Service Medium - GS-M
Proposed Revenue vs Cost of Service
Demand at 200 kW
$14,000.00
$12,000.00
$10,000.00
$8,000.00
$6,000.00
$4,000.00
$2,000.00
$-
Monthly Bill
10,000
20,000
30,000
40,000
50,000
60,000
70,000
80,000
90,000
100,000
110,000
120,000
130,000
140,000
kWh Energy Usage
Cost of Service
Proposed Revenue


Met-Ed General Service Large - GS-L
Proposed Revenu vs Cost of Service
Demand at 500 kW
$25,000.00
$20,000.00
$15,000.00
$10,000.00
$5,000.00
$-
Monthly Bill
150,000
162,500
175,000
187,500
200,000
212,500
225,000
237,500
250,000
262,500
275,000
287,500
300,000
312,500
kWh Energy Usage
Cost of Service
Proposed Revenue


Met-Ed General Service Primary - GP
Proposed Revenue vs Cost of Service
Demand of 1,000 kW
$45,000.00
$40,000.00
$35,000.00
$30,000.00
$25,000.00
$20,000.00
$15,000.00
$10,000.00
$5,000.00
$-
Monthly Bill
300,000
325,000
350,000
375,000
400,000
425,000
450,000
475,000
500,000
525,000
550,000
575,000
600,000
625,000
kWh Energy Usage
Cost of Service
Proposed Revenue


Met-Ed General Service Primary - TP
Proposed Revenue vs Cost of Service
Demand of 10,000 kW
$350,000.00
$300,000.00
$250,000.00
$200,000.00
$150,000.00
$100,000.00
$50,000.00
$-
Monthly Bill
3,500,000
3,750,000
4,000,000
4,250,000
4,500,000
4,750,000
5,000,000
5,250,000
5,500,000
5,750,000
6,000,000
6,250,000
6,500,000
6,750,000
kWh Energy Usage
Cost of Service
Proposed Revenue

METROPOLITAN EDISON COMPANY

TITLE 52, SECTION 53.52 (a) FILING REQUIREMENT:

"(a) Whenever a public utility, other than a canal, turnpike, tunnel, bridge or wharf company files a tariff, revision or supplement effecting changes in the terms and conditions of service rendered or to be rendered, it shall submit to the Commission, with the tariff, revision or supplement, statements showing all of the following:
(1) The specific reasons for each change.
(2) The total number of customers served by the utility.
(3) A calculation of the number of customers, by tariff subdivision, whose bills will be affected by the change.
(4) The effect of the change on the utility's customers.
(5) The direct or indirect effect of the proposed change on the utility's revenue and expenses.
(6) The effect of the change on the service rendered by the utility.
(7) A list of factors considered by the utility in its determination to make the change. The list shall include a comprehensive statement about why these factors were chosen and the relative importance of each. This subsection does not apply to a portion of a tariff change seeking a general rate increase as defined in 66 Pa.C.S. § 1308 (relating to voluntary changes in rates).
(8) Studies undertaken by the utility in order to draft its proposed change. This paragraph does not apply to a portion of a tariff change seeking a general rate increase as defined in 66 Pa.C.S. § 1308.
(9) Customer polls taken and other documents which indicate customer acceptance and desire for the proposed change. If the poll or other documents reveal discernible public opposition, an explanation of why the change is in the public interest shall be provided.
(10) Plans the utility has for introducing or implementing the changes with respect to its ratepayers.
(11) FCC, FERC or Commission orders or rulings applicable to the filing."

RESPONSE:

52 Pa. Code 53.52(a)(1)

Q. The specific reasons for each change.

A. See Testimony of Kevin M. Siedt, Met-Ed/Penelec/Penn Power/West Penn Statement No. 4.

52 Pa. Code 53.52(a)(2)

Q. The total number of Customers served by the utility.

A. As of March 2014, the end of the historical test year, Met-Ed served a total of 557,266 customers.

52 Pa. Code 53.52(a)(3)

Q. A calculation of the number of Customers, by tariff subdivision, whose bills could be affected by the change.

A. See Met-Ed Exhibit KMS-1, Attachment A, B, and C, Sales and Distribution Revenue Normalization (Fully Projected, Future, and Historical Test Years, respectively)

52 Pa. Code 53.52(a)(4)

Q. The effect of the change on the utility's customers.

A. See Met-Ed Exhibit KMS-6, Comparison between Present and Proposed Rates, and Met-Ed/Penelec/Penn Power/West Penn Statement No. 4, Direct Testimony of Kevin M. Siedt.

52 Pa. Code 53.52(a)(5)

Q. The direct or indirect effect of the proposed change on the utility's revenue and expenses.

A. See Met-Ed/Penelec/Penn Power/West Penn Statement No. 2, Direct Testimony of Richard A. D'Angelo and Exhibits RAD 1 and 2.

52 Pa. Code 53.52(a)(6)

Q. The effect of the change on the service rendered by the utility

A. See Met-Ed/Penelec/Penn Power/West Penn Statement No. 1, Direct Testimony of Charles V. Fullem.

52 Pa. Code 53.52(a)(7)

Q. A list of factors considered by the utility in its determination to make the change. The list shall include a comprehensive statement about why these factors were chosen and the relative importance of each. This subsection does not apply to a portion of a tariff change seeking a general rate increase as defined in 66 Pa.C.S. § 1308 (relating to voluntary changes in rates).

A. Not applicable.

52 Pa. Code 53.52(a)(8)

Q. Studies undertaken by the utility in order to draft its proposed change. This paragraph does not apply to a portion of a tariff change seeking a general rate increase as defined in 66 Pa.C.S. § 1308.

A. Not Applicable.

52 Pa. Code 53.52(a)(9)

Q. Customer polls taken and other documents which indicate customer acceptance and desire for the proposed change. If the poll or other documents reveal discernible public opposition, an explanation of why the change is in the public interest shall be provided.

A. None

52 Pa. Code 53.52(a)(10)

Q. Plans the utility has for introducing or implementing the changes with respect to its ratepayers.

A. At the time of filing, the Company will issue and provide to customers notice of its distribution rate increase request pursuant to the Commission's general rate case filing regulations. A customer bill insert will describe the rate changes approved by the Commission and indicate the impact on customers. The Company will also inform customers about the Commission-approved rate changes in news releases and on the Company's Internet site. After a final Commission Order is entered in connection with this rate filing, the Company will file a compliance tariff to implement all of the approved changes.

52 Pa. Code 53.52(a)(11)

Q. FCC, FERC or Commission orders or rulings applicable to the filing.

A. The following orders or rulings are applicable to the filing:

- Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company for approval of Their Default Service Programs, Docket Nos. P-2011-2273650, P-2011-2273668, P-2011-2273669, and P-2011-2273670.
- Investigation of Pennsylvania's Retail Electricity Market Intermediate Work Plan, Docket No. I-2011-2237952.
- Merger Settlement, Docket Nos. A-2010-2176520 and A-2010-2176732.
- Companies' Smart Meter Deployment Plan, Docket Nos. M-2013-2341990, M-2013-2341991, M-2013-2341993, and M-2013-2341994.
- Met-Ed and Penelec 2007 Rate Case order, Docket No. R-0061366 and R-0061367.

TITLE 52, SECTION 53.52 (b) FILING REQUIREMENT:

"(b) Whenever a public utility other than a canal, turnpike, tunnel, bridge or wharf company files a tariff, revision or supplement which will increase or decrease the bills to its customers, it shall submit in addition to the requirements of subsection (a), to the Commission, with the tariff, revision or supplement, statements showing the following:
(1) The specific reasons for each increase or decrease.
(2) The operating income statement of the utility for a 12-month period, the end of which may not be more than 120 days prior to the filing. Water and wastewater utilities with annual revenues under $100,000 and municipal corporations subject to Commission jurisdiction may provide operating income statements for a 12-month period, the end of which may not be more than 180 days prior to the filing.
(3) A calculation of the number of customers, by tariff subdivision, whose bills will be increased.
(4) A calculation of the total increases, in dollars, by tariff subdivision, projected to an annual basis
(5) A calculation of the number of customers, by tariff subdivision, whose bills will be decreased.
(6) A calculation of the total decreases, in dollars, by tariff subdivision, projected to an annual basis.."

RESPONSE:

Metropolitan Edison Company ("Met-Ed" or the "Company") submits the following information in support of Tariff Electric – Pa. P.U.C. No. 52. In response to each of the applicable subsections of 52 Pa. Code 53.52(b), Met-Ed states the following:

52 Pa. Code 53.52(b)(1)

Q. The specific reasons for each increase or decrease.

A. See Testimony of Charles V. Fullem, Met-Ed/Penelec/Penn Power/West Penn Statement No. 1, Testimony of Richard A. D'Angelo, Met-Ed/Penelec/Penn Power/West Penn Statement No. 2, Testimony of Kimberlie L. Bortz, Met-Ed/Penelec/Penn Power/West Penn Statement No. 3, and Testimony of Kevin M. Siedt, Met-Ed/Penelec/Penn Power/West Penn Statement No. 4.

52 Pa. Code 53.52(b)(2)

Q. The operating income statement of the utility for a 12-month period, the end of which may not be more than 120 days prior to the filing.

A. See Met-Ed Exhibit RAD-4.

52 Pa. Code 53.52(b)(3)

Q. A calculation of the number of customers, by tariff subdivision, whose bills will be increased.

A. See Met-Ed Exhibit KMS-1, Attachment A, B, and C, Sales and Distribution Revenue Normalization (Fully Projected, Future, and Historical Test Years, respectively), Met-Ed Exhibit KMS-2, Summary of Distribution of Revenues, Met-Ed Exhibit KMS-5, Proof of Revenues Analysis, and Met-Ed Exhibit KMS-6, Bill Comparisons.

52 Pa. Code 53.52(b)(4)

Q. A calculation of the total increases, in dollars, by tariff subdivision, projected to an annual basis.

A. See Met-Ed Exhibit KMS-2, Summary of Distribution of Revenues, Met-Ed Exhibit KMS-5, Proof of Revenues Analysis, and Met-Ed Exhibit KMS-6, Bill Comparisons.

52 Pa. Code 53.52(b)(5)

Q. A calculation of the number of customers, by tariff subdivision, whose bills will be decreased.

A. See Met-Ed Exhibit KMS-2, Summary of Distribution of Revenues, Met-Ed Exhibit KMS-5, Proof of Revenues Analysis, and Met-Ed Exhibit KMS-6, Bill Comparisons.

52 Pa. Code 53.52(b)(6)

Q. A calculation of the total decreases, in dollars, by tariff subdivision, projected to an annual basis.

A. See Met-Ed Exhibit KMS-2, Summary of Distribution of Revenues, Met-Ed Exhibit KMS-5, Proof of Revenues Analysis, and Met-Ed Exhibit KMS-6, Bill Comparisons.

TITLE 52, SECTION 53.52 (c) FILING REQUIREMENT:

> "(c) If a public utility files a tariff, revision or supplement which it is calculated will increase the bills of a customer or a group of customers by an amount, when projected to an annual basis, exceeding 3% of the operating revenues of the utility—subsection (b)(4) divided by the operating revenues of the utility for a 12-month period as defined in subsection (b)(2)—or which it is calculated will increase the bills of 5% or more of the number of customers served by the utility—subsection (b)(3) divided by subsection (a)(2)—it shall submit to the Commission with the tariff, revision or supplement, in addition to the statements required by subsections (a) and (b), all of the following information:
> (1) A statement showing the utility's calculation of the rate of return or operating ratio (if the utility qualifies to use an operating ratio under § 53.54 (relating to small water and wastewater utilities) earned in the 12-month period referred to in subsection (b)(2), and the anticipated rate of return or operating ratio to be earned when the tariff, revision or supplement becomes effective. The rate base used in this calculation shall be supported by summaries of original cost for the rate of return calculation. When an operating ratio is used in this calculation, it shall be supported by studies of margin above operation and maintenance expense plus depreciation as referred to in § 53.54(b)(2)(B).
> (2) A detailed balance sheet of the utility as of the close of the period referred to in subsection (b)(2).
> (3) A summary, by detailed plant accounts, of the book value of the property of the utility at the date of the balance sheet required by paragraph (2).
> (4) A statement showing the amount of the depreciation reserve, at the date of the balance sheet required by paragraph (2), applicable to the property, summarized as required by paragraph (3).
> (5) A statement of operating income, setting forth the operating revenues and expenses by detailed accounts for the 12-month period ending on the date of the balance sheet required by paragraph (2).
> (6) A brief description of a major change in the operating or financial condition of the utility occurring between the date of the balance sheet required by paragraph (2) and the date of transmittal of the tariff, revision or supplement. As used in this paragraph, a major change is one which materially alters the operating or financial condition of the utility from that reflected in paragraphs (1)—(5)."

RESPONSE:

See Met-Ed/Penelec/Penn Power/West Penn Statement No. 2, Testimony of Richard A. D'Angelo and Exhibit RAD 54 and Exhibit RAD 55.

TITLE 52, SECTION 53.52 (d) FILING REQUIREMENT:

> "(d) If a utility renders more than one type of public service, such as electric and gas, information required by § § 53.51—53.53 (relating to information furnished with the filing of rate changes), except subsection (c)(2), relates solely to the kind of service to which the tariff or tariff supplement is applicable. In subsection (c)(2), the book value of property used in furnishing each type of public service, as well as the depreciation reserve applicable to the property, shall be shown separately."

RESPONSE:

See Met-Ed/Penelec/Penn Power/West Penn Statement No. 2, Testimony of Richard A. D'Angelo and Exhibit RAD 54 and Exhibit RAD 55.

FILING REQUIREMENT IV-A-1:

"Provide a summary schedule of the individual rate effects. For each state jurisdictional rate, show the following information to the test period elected:

1. Rate schedule designation."

FILING REQUIREMENT IV-A-2:

"Provide a summary schedule of the individual rate effects. For each state jurisdictional rate, show the following information to the test period elected:

2. For existing rates:
   a. Customers served as of end of period.
   b. Annual Kwh sales
   c. Base rate revenues adjusted for any changes in base rate application that may have occurred during the test period.
   d. Tax surcharge revenues.
   e. Energy Cost adjustment clause revenues.
   f. Revenues received from other clauses or riders separately accounted for.
   g. Total of all revenues."

FILING REQUIREMENT IV-A-3:

"Provide a summary schedule of the individual rate effects. For each state jurisdictional rate, show the following information to the test period elected:

3. For proposed rates:
(a) Estimated number of customers whose charges for electric service will be increased or decreased as a result of this filing.
(b) Base rate revenues:
   (1) Annual dollar amount of increase or decrease.
   (2) Percentage change.
(c) Estimated tax surcharge revenues based on the assumption that the base rate changes proposed were in place.
(d) Estimated Energy cost adjustment clause revenues.
(e) Revenues received from other clauses or riders separately accounted for.
(f) Total of all revenues:
   (1) Amount of total annual dollar change.
   (2) Percentage change."

FILING REQUIREMENT IV-A-4:

"Provide a summary schedule of the individual rate effects. For each state jurisdictional rate, show the following information to the test period elected:

4. Supplement the revenue summary to obtain a complete revenue statement of the electric business, that is, show delayed payments, other electric revenues, FERC jurisdictional sales and revenues and all other appropriate revenue items and adjustments."

FILING REQUIREMENT IV-A-5:

"Provide a summary schedule of the individual rate effects. For each state jurisdictional rate, show the following information to the test period elected:

5. Develop the grand total showing total sales and revenues as adjusted and the various increases and decreases and percent effects as described above."

RESPONSES:

See Met-Ed Exhibit KMS-1, Attachment A, B, and C, Sales and Distribution Revenue Normalization (Fully Projected, Future, and Historical Test Years, respectively), Met-Ed Exhibit KMS-2, Summary of Distribution of Revenues.

FILING REQUIREMENT IV-C:

> "The annual revenue effect of any proposed change to any rate must be supported by a billing analysis. This may consist of the use of bill frequency distributions or individual customer billing records for the most recent annual periods available. All billing determinants should be displayed. The blocking and corresponding prices of the existing rate and the proposed rate should be applied to the determinants to derive the base rate revenues under both present and proposed rates. The derived base rate revenues should form the basis for measuring the annual base rate effect of the rates in question for the test periods."

RESPONSE:

See Met-Ed Exhibit KMS-5, Proof of Revenues Analysis.

FILING REQUIREMENT IV-D-1:

"The effects of the proposed rates on monthly billing conditions should be provided as follows:

1. *Residential Bill Comparisons*

   For each rate applicable to residential service provide a chart or tabulation which shows the dollar and percentage effect of the proposed base rate on monthly bills ranging from the use of zero kWh to 5,000 kWh at appropriate intervals."

FILING REQUIREMENT IV-D-2:

"The effects of the proposed rates on monthly billing conditions should be provided as follows:

2. *General Bill Comparisons*

   For each rate that requires both a billing demand (kW) and kWh's as the billing determinants, provide a tabulation or graphical comparison showing the percentage effect of the proposed base rate on monthly bills using several representative demand (kW) levels, the monthly kWh for each demand selected to be in load factor increments of 10% starting at 0% and ending at 100% (730H) or by hours' use increments that covers approximately 95% of the bills."

RESPONSE:

See Met-Ed Exhibit KMS-6, Comparison between Present and Proposed Rates.

FILING REQUIREMENT IV-E-2:

> "Provide comparisons in either graphical or tabular form showing cost, as defined in the cost of service study, and proposed base rate revenues and usage for all residential and demand/energy rate schedules. Demand shall be for representative loads for each demand/energy rate schedule."

RESPONSE:

See Met-Ed Exhibit KMS-7, Cost Curves.

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 10

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2014-2428745

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. R-2014-2428743

PENNSYLVANIA POWER COMPANY
DOCKET NO. R-2014-2428744

WEST PENN POWER COMPANY
DOCKET NO. R-2014-2428742

Direct Testimony of Steven R. Staub

List of Topics Addressed

Capital Structure
Cost of Long Term Debt
Cost of Common Equity
Weighted Average Cost of Capital

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DIRECT TESTIMONY
OF
STEVEN R. STAUB

I. INTRODUCTION AND PURPOSE

Q. Please state your name and business address.

A. My name is Steven R. Staub and my business address is 76 South Main Street, Akron, Ohio 44308.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company as Vice President and Treasurer.

Q. What are your current responsibilities?

A. I am responsible for Treasury activities including capital markets, cash management, derivatives, investment management, and debt compliance. I am also responsible for Business Planning activities including budgeting, forecasting, and financial planning. My responsibilities extend to each of the companies owned by FirstEnergy Corp., including its distribution operating companies.

Q. What is your educational and professional background?

A. I am a graduate of the University of Pittsburgh with undergraduate degrees in Business/Accounting and Political Science. I received an MBA from the University of Pittsburgh and a Master of Taxation from Robert Morris University. I have over twenty years of professional experience in finance related-positions,

including fifteen years with the regulated utility industry. My work and testimonial experience is more fully outlined in Appendix A.

Q. On whose behalf are you testifying in this matter?

A. I am testifying on behalf of Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power"), and West Penn Power Company ("West Penn") (collectively, the "Companies"). My testimony applies to all of the Companies, unless otherwise stated.

Q. What is the purpose of your direct testimony?

A. My testimony describes and supports the capital structure, embedded cost of long-term debt and overall weighted average cost of capital claimed by each of the four Companies. In addition, I explain why the Companies have requested that their authorized return on common equity be set at the high end of the range of values developed by their outside consultant on the cost of capital, Dr. Michael J. Vilbert of The Brattle Group.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring responses to various standard filing requirements dealing with financial matters, which responses are sequentially numbered as Exhibits SRS-1 through SRS-21 for each of the Companies. In addition, I am sponsoring the following summary schedules for each of the four Companies, which will be discussed further in this testimony:

Exhibits SRS-22: Capitalization and Capitalization Ratios

Exhibits SRS-23: Schedule of Long-Term Debt Outstanding Projected at April 30, 2016

Exhibits SRS-24: Capital Cost Rates April 30, 2016

Each of these exhibits were prepared by me or under my supervision.

II. CAPITAL STRUCTURE

Q. What capital structure ratios are you proposing be utilized for purposes of determining the Companies' overall weighted average costs of capital?

A. I recommend use of each Company's projected capital structure at April 30, 2016, exclusive of short-term debt. That date corresponds to the end of the fully projected future test year in these proceedings and, accordingly, reflects the mix of long-term debt and common equity capital that will support the Companies' claimed rate bases.

Q. Why have you excluded short-term debt from your proposed capital structure ratios?

A. Short-term borrowings typically are sources of liquidity and are not utilized to finance long-lived assets, such as those included in the Companies' claimed rate bases. In addition, it is my understanding that the Pennsylvania Public Utility Commission typically excludes short-term debt from a utility's capital structure in base rate cases.

Q. How did you derive the Companies' anticipated capital structure ratios at April 30, 2016?

A. As set forth in Exhibits SRS-22, the starting point was the actual capital structure in place at March 31, 2014, which represents the end of the historic test year. Then, based on recent financial forecasts, the respective amounts of long-term debt and common equity[1] were adjusted forward to March 31, 2015, the end of the future test year, and to April 30, 2016, the end of the fully projected future test year, to capture: (1) consummated and planned issuances of long-term debt (Met-Ed and Penelec in 2014 and Penn Power and West Penn prior to April 30, 2016); (2) the pay down of long-term debt; (3) the amortization of long-term debt discount and, in the case of West Penn, certain fair value adjustments booked in accordance with the FirstEnergy / Allegheny Energy merger; and (4) anticipated increases in retained earnings.

Q. What specific capital structure ratios do you recommend be adopted for rate of return purposes in this case?

A. Since rate setting is prospective, the rate of return should reflect a utility's expected capital structure at the end of the test year. I therefore recommend the adoption of the projected April 30, 2016 capital structure ratios set forth below:

Company	Long-Term Debt	Common Equity
Met-Ed	50.0%	50.0%
Penelec	50.1%	49.9%
Penn Power	49.9%	50.1%
West Penn	49.9%	50.1%

[1] None of the four Companies has any preferred or preference stock outstanding.

III. COST OF LONG-TERM DEBT

Q. What cost rates have you assigned to the long-term debt component of the Companies' capital structures?

A. The determination of a utility's weighted average long-term debt cost rate is essentially an arithmetic exercise due to the fact that the utility has contracted for the use of the capital in question for a defined period of time at a specified cost rate. The necessary calculations, which take into account issuance expense and, in the case of Penn Power, annual sinking fund requirements, are provided in Exhibits SRS-23.

Q. Please describe what is shown in Exhibits SRS-23.

A. Exhibits SRS-23 itemize each series of debt, the date of issuance, maturity, original amount issued and projected amount outstanding as of April 30, 2016. The Premium/Discount and Issuance Expenses column represents legal, underwriting and other miscellaneous costs associated with each issuance. The principal amount issued, adjusted for any premium or discount, less any issuance expenses equals the Net Proceeds. The effective rate is calculated by taking the Net Proceeds at the time of issuance and calculating the Internal Rate of Return based on the interest rate and the years to maturity. After the effective rate is calculated for each individual series, the rates are weighted by taking the effective rate multiplied by each respective amount outstanding divided by the total adjusted amount of long-term debt outstanding.

Q. What long-term debt cost rates do you recommend be utilized in developing the Companies' overall costs of capital?

A. As indicated in Exhibits SRS-23 and as summarized below, the Companies' weighted average long-term debt cost rates range from 5.21% (Met-Ed) to 6.12% (Penn Power):

Company	Long-Term Debt Cost Rate
Met-Ed	5.21%
Penelec	5.72%
Penn Power	6.12%
West Penn	5.38%

IV. COST OF COMMON EQUITY

Q. What rate of return on common equity ("ROE") are the Companies requesting authorization to earn?

A. The Companies seek a reasonable opportunity to earn an ROE of 10.9%. As noted previously, this represents the upper end of the cost of equity range determined by Dr. Vilbert, and is more fully explained in Met-Ed/Penelec/Penn Power/West Penn Statement No. 9.

Q. Why do you believe that the Companies should be provided an ROE at the high end of Dr. Vilbert's range?

A. For several reasons. First, the Companies project the need to make very significant capital investments over the next five to ten years as they install smart meters and replace and rehabilitate aging infrastructure to ensure reliability. To

that end, it is critically important that they maintain a healthy financial profile so they can access the capital markets on reasonable terms.

Second, and as pointed out by Dr. Vilbert, capital-intensive entities such as the Companies face considerable uncertainty as to the future course of the capital markets. In my view, short and medium term interest rates will likely not go any lower than they are today and, in all probability, will begin to trend upwards in 2015. Consequently, my proposed 10.9% equity allowance reflects, in part, my expectation that capital costs are far more likely to increase than they are to decrease or remain flat during the period that the new rates are in effect. Furthermore, setting rates with a ROE that is below that of other investment opportunities of corresponding risk will imperil the Companies' ability to maintain their financial integrity and continue to attract capital at reasonable rates and terms.

Third, the Companies have taken a number of positive steps over the past several years to control costs, improve customer service, and promote retail electric competition, as described by Mr. Fullem in Met-Ed/Penelec/Penn Power/West Penn Statement No. 1. I believe all of these efforts should be considered as favorable factors in setting the Companies' authorized ROE.

V. OVERALL COST OF CAPITAL

Q. How did you calculate the Companies' overall costs of capital?

A. As set forth in the respective Exhibits SRS-24, I quantified, and then combined, each Company's weighted average costs of long-term debt and common equity by

multiplying the projected April 30, 2016 capitalization ratios presented in Exhibit SRS-22 by: (1) the average cost of debt developed on Exhibits SRS-23; and (2) the recommended ROE of 10.9%. The results are as follows:

Company	Overall Weighted Cost of Capital
Met-Ed	8.05%
Penelec	8.31%
Penn Power	8.51%
West Penn	8.14%

Q. Does that conclude your direct testimony at this time?

A. Yes, it does.

Resume: Education and Experience of Steven R. Staub

Education:

1993	Bachelor of Science Degree in Business/Accounting and Political Science – University of Pittsburgh
1997	Masters of Business Administration Degree – University of Pittsburgh
2007	Master of Taxation – Robert Morris University

Experience:

4/94 – 2/98	Finance-related positions in the corporate banking, capital markets, and securities lending divisions – Mellon Bank
2/98 – 8/99	Senior Finance Analyst – Ford Motor Company
8/99 – 9/02	Senior Financial Consultant – Duquesne Light Company
9/02 – 12/03	Manager of Corporate Finance – Duquesne Light Company
12/03 – 11/07	Assistant Treasurer – Duquesne Light Company
12/07 – 8/12	Assistant Treasurer – Allegheny Energy Inc. (FirstEnergy)
8/12 – 12/12	Executive Director and Assistant Treasurer – FirstEnergy
12/12 – Present	Vice President and Treasurer – FirstEnergy

Prior Rate Case Testimony:

Public Service Commission of West Virginia	Case No. 12-1571-E-PC Case No. 14-0702-E-42T
New Jersey Board of Public Utilities	BPU Docket No. ER12111052 OAL Docket No. PUC16310-2012N

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-B-5:

"If a claim is made for compensating bank balances, provide the following information:

(a) Name and address of each bank.
(b) Types of accounts with each bank – checking, savings, escrow, other services, and the like.
(c) Average daily balance in each account.
(d) Amount and percentage requirements for compensating bank balance at each bank.
(e) Average daily compensating bank balance at each bank.
(f) Documents from each bank explaining compensating bank balance requirements.
(g) Interest earned on each type of account.
(h) A calculation showing the average daily float for each bank."

RESPONSE:

No compensating bank balances are maintained.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT II-E-2:

"Supply summaries of the utility's projected operating and capital budgets for the 2 calendar years following the end of the test year."

RESPONSE:

This information is not available at this time.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-A-1:

"Provide a schedule showing the major components of claimed capitalization, and the derivation of the weighted costs of capital for the rate case claim. This schedule shall include a descriptive statement concerning the major elements of changes in claimed capitalization, cost rates and overall return from comparable historical data."

RESPONSE:

See the testimony and exhibits of Steven R Staub.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-A-2:

"Provide a schedule in the same format as Schedule 1, except for the omission of the descriptive statement, for the most immediate comparable annual historical period prior to the test year and the two calendar years most immediately preceding the rate of return claim period. Irrespective of whether the capitalization claimed on Schedule 1 includes short-term debt, Schedule 2 should reflect capital ratios with and without short-term debt."

RESPONSE:

See ME Exhibit SRS-4 Attachment A

Metropolitan Edison Company
Capitalization & Capitalization Ratios
($000)

	Actuals at March 31, 2013			Actuals at March 31, 2014			Forecast at March 31, 2015			Forecast at April 30, 2016		
	Amount	Ratios		Amount	Ratios		Amount	Ratios		Amount	Ratios	
	Outstanding	Excl. S-T-Debt	Incl. S-T-Debt	Outstanding	Excl. S-T-Debt	Incl. S-T-Debt	Outstanding	Excl. S-T-Debt	Incl. S-T-Debt	Outstanding	Excl. S-T-Debt	Incl. S-T-Debt
Long Term Debt [1]	877,999	52.7%	49.9%	778,118 [2]	48.8%	44.9%	849,661 [2]	50.4%	49.3%	849,707 [2]	50.0%	48.5%
Preferred Stock	0	0.0%	0.0%	0	0.0%	0.0%	0	0.0%	0.0%	0	0.0%	0.0%
Common Equity	788,885	47.3%	44.9%	817,892	51.2%	47.2%	834,704	49.6%	48.4%	848,489	50.0%	48.5%
Total Permanent Capital	1,666,884	100.0%	94.8%	1,596,010	100.0%	92.1%	1,684,365	100.0%	97.7%	1,698,196	100.0%	97.0%
Short-term Debt	91,306		5.2%	136,845		7.9%	39,888		2.3%	52,077		3.0%
Total Capital	1,758,190		100.0%	1,732,855		100.0%	1,724,253		100.0%	1,750,273		100.0%

Notes: [1] Includes current portion of long-term debt

[2] Reflects changes in long-term debt of:

new long-term debt issues	0	250,000	issued in June 2014	0
long-term debt paydown	(100,000)	(178,500)		0
Unamort Discount on long-term debt	119	43		46

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-B-1:

"Provide a schedule showing the calculation of embedded cost of long-term debt by issue, supporting the related rate case claim. The schedule shall contain the following information:

a. Date of issue.
b. Date of maturity.
c. Amount issued.
d. Amount outstanding.
e. Amount retired.
f. Amount reacquired.
g. Gain or loss on reacquisition.
h. Coupon rate.
i. Discount or premium at issuance.
j. Issuance expense.
k. Net proceeds.
l. Sinking fund requirements.
m. Effective cost rate.
n. Total average weighted effective cost rate.

Projected new issues, retirements and other major changes from the comparable historic data should be clearly noted."

RESPONSE:

See ME Exhibit SRS-5 Attachment A.

Met-Ed
Schedule of Long Term Debt Outstanding at 4/30/2016

Title	Date of Offering	Date of Maturity	Principal Amount Issued	Amount Outstanding	Amount Retired	Amount Reacquired	Gain (Loss) on Reacquisition	Interest Rate	Prem / (Disc) & (Issuance) Expenses	Net Proceeds	Annual / Sinking Fund	Effective Rate	Total Average Weighted Effective Cost Rate
Senior Unsecured Notes													
4.000% Senior Notes	6/11/2014	4/15/2025	250,000,000	250,000,000				4.0000%	(2,874,442)	247,125,558		4.1321%	
3.50% Senior Notes	3/15/2013	3/15/2023	300,000,000	300,000,000				3.5000%	(426,000)	299,574,000		3.5170%	
7.70% Senior Notes	1/20/2009	1/15/2019	300,000,000	300,000,000				7.7000%	(1,950,000)	298,050,000		7.7950%	
			850,000,000	**850,000,000**	**-**				**(5,250,442)**	**844,749,558**			**5.2078%**

Met-Ed
Schedule of Long Term Debt Outstanding at 3/31/2015

Title	Date of Offering	Date of Maturity	Principal Amount Issued	Amount Outstanding	Amount Retired	Amount Reacquired	Gain (Loss) on Reacquisition	Interest Rate	Prem / (Disc) & (Issuance) Expenses	Net Proceeds	Annual / Sinking Fund	Effective Rate	Total Average Weighted Effective Cost Rate
FMB / PCN													
BCIDA Series	3/16/2011	4/16/2014	28,500,000	-	(28,500,000)			N/A	(88,000)	28,412,000		N/A	
			28,500,000	**-**	**(28,500,000)**				(88,000)	**28,412,000**			**N/A**
Senior Unsecured Notes													
4.000% Senior Notes	6/11/2014	4/15/2025	250,000,000	250,000,000				4.0000%	(2,874,442)	247,125,558		4.1321%	
4.875% Senior Notes	3/25/2004	4/1/2014	250,000,000	-	(250,000,000)			4.8750%	(2,392,500)	247,607,500		4.9978%	
3.50% Senior Notes	3/15/2013	3/15/2023	300,000,000	300,000,000				3.5000%	(426,000)	299,574,000		3.5170%	
7.70% Senior Notes	1/20/2009	1/15/2019	300,000,000	300,000,000				7.7000%	(1,950,000)	298,050,000		7.7950%	
			1,100,000,000	**850,000,000**	**(250,000,000)**				**(7,642,942)**	**1,092,357,058**			**5.2078%**
			1,128,500,000	**850,000,000**	**(278,500,000)**				**(7,730,942)**	**1,120,769,058**			**5.2078%**

Met-Ed
Schedule of Long Term Debt Outstanding at 3/31/2014

Title	Date of Offering	Date of Maturity	Principal Amount Issued	Amount Outstanding	Amount Retired	Amount Reacquired	Gain (Loss) on Reacquisition	Interest Rate	Prem / (Disc) & (Issuance) Expenses	Net Proceeds	Annual / Sinking Fund	Effective Rate	Total Average Weighted Effective Cost Rate
FMB / PCN													
2005 Series A - Beaver County IDA (1)	12/6/2005	4/16/2014	28,500,000	28,500,000				0.0700%	(88,000)	28,412,000		0.0901%	
			28,500,000	**28,500,000**					(88,000)	**28,412,000**			**0.0901%**
Senior Unsecured Notes													
4.875% Senior Notes	3/25/2004	4/1/2014	250,000,000	150,000,000	(100,000,000)			4.8750%	(2,392,500)	247,607,500		4.9978%	
3.50% Senior Notes	3/15/2013	3/15/2023	300,000,000	300,000,000				3.5000%	(426,000)	299,574,000		3.5170%	
7.70% Senior Notes	1/20/2009	1/15/2019	300,000,000	300,000,000				7.7000%	(1,950,000)	298,050,000		7.7950%	
			850,000,000	**750,000,000**	**(100,000,000)**				(4,768,500)	**845,231,500**			**5.5244%**
			878,500,000	**778,500,000**	**(100,000,000)**				**(4,856,500)**	**873,643,500**			**5.3254%**

Met-Ed
Schedule of Long Term Debt Outstanding at 3/31/2013

Title	Date of Offering	Date of Maturity	Principal Amount Issued	Amount Outstanding	Amount Retired	Amount Reacquired	Gain (Loss) on Reacquisition	Interest Rate	Prem / (Disc) & (Issuance) Expenses	Net Proceeds	Annual / Sinking Fund	Effective Rate	Total Average Weighted Effective Cost Rate
FMB / PCN													
2005 Series A - Beaver County IDA	12/6/2005	4/16/2014	28,500,000	28,500,000				0.1400%	(88,000)	28,412,000		0.1702%	
			28,500,000	**28,500,000**					(88,000)	**28,412,000**			**0.1702%**
Senior Unsecured Notes													
4.875% Senior Notes	3/25/2004	4/1/2014	250,000,000	250,000,000				4.8750%	(2,392,500)	247,607,500		4.9978%	
3.50% Senior Notes	3/15/2013	3/15/2023	300,000,000	300,000,000				3.5000%	(426,000)	299,574,000		3.5170%	
7.70% Senior Notes	1/20/2009	1/15/2019	300,000,000	300,000,000				7.7000%	(1,950,000)	298,050,000		7.7950%	
			850,000,000	**850,000,000**					(4,768,500)	**845,231,500**			**5.4624%**
			878,500,000	**878,500,000**					**(4,856,500)**	**873,643,500**			**5.2907%**

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-B-2:

"In the event that a claim made for a true or economic cost of debt exceeds that shown in the preceding nominal cost schedule because of convertible features, sale with warrants or for any other reason, a full statement of the basis for such a claim should be provided."

RESPONSE:

Not applicable.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-B-3:

"Provide the following information concerning bank notes payable for test year and for latest comparable annual historical period prior to the test year:

a. Line of credit at each bank.
b. Average daily balances of notes to each bank, by name of bank.
c. Interest rate charged on each bank note (Prime rate, formula rate, or other).
d. Purpose of each bank note (for example, construction, fuel storage, working capital, debt retirement).
e. Prospective future need for this type of financing."

RESPONSE:

a. Metropolitan Edison can borrow up to $500 mm under the FirstEnergy Corp. Revolving Credit. Royal Bank of Scotland (RBS) is the administrative agent for this credit facility.

b. As of 12/31/2013 Metropolitan Edison had a balance of $50 mm with the FirstEnergy Corp. Revolving Credit.
As of 3/31/2014 Metropolitan Edison had a balance of $75 mm with the FirstEnergy Corp. Revolving Credit.

c. As of 12/31/2013 interest rate was at 1.69%.
As of 3/31/2014 the interest rate was 1.71%

d. Working Capital Requirements

e. Working Capital Requirements

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-B-4:

"Provide detailed information concerning all other short-term debt outstanding."

RESPONSE:

Metropolitan Edison is a participant in the Utility Money Pool and borrows and invests in the pool as needed. The balance borrowed from the Utility Money Pool at 12/31/2013 was $24.8 mm and the borrowing rate was 1.31%. The balance borrowed from the Utility Money Pool at 3/31/2014 was $61.8 mm and the borrowing rate was 1.61%.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-C:

"Provide a schedule showing the calculation of the embedded cost of preferred stock equity by issue, supporting the related rate case claim. The schedule shall contain the following information:

a. Date of issue.
b. Date of maturity.
c. Amount issued.
d. Amount outstanding.
e. Amount retired.
f. Amount reacquired.
g. Gain or loss on reacquisition.
h. Dividend rate.
i. Discount or premium issuance.
j. Issuance expenses.
k. Net proceeds.
l. Sinking fund requirements.
m. Effective cost rate.
n. Total average weighted effective cost rate.

Projected new issues, retirement and other major changes from the comparable historical data should be clearly noted."

RESPONSE:

Not applicable

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-D-2:

"Provide a summary statement of all stock dividends, splits or par value changes during the 2 calendar year period preceding the rate case filing."

RESPONSE:

See file ME Exhibit SRS-10 Req III-D-2_Attachment A

Metropolitan Edison Company

Common Stock Dividend Record

Payment Date	Common Dividend	Return of Capital	Stock Re-purchase
Jun-12		20,000,000	
Oct-12		10,000,000	
Dec-12		15,000,000	
Mar-13		30,000,000	

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-D-3:

"Provide a schedule of all issuances of common stock, whether or not underwriters are used, for the most immediately available annual historical period and the 2 calendar years most immediately preceding the test year."

RESPONSE:

Not applicable.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-D-4:

"Submit details on the utility and parent company stock offerings—past 5 years to present - as follows:

a. Date of prospectus.
b. Date of offering.
c. Record date.
d. Offering period – dates and numbers of days.
e. Amount and number of shares offered.
f. Offering ratio, if rights offering.
g. Percent subscribed.
h. Offering price.
i. Gross proceeds per share.
j. Expenses per share.
k. Net proceeds per share (i—j).
l. Market price per share.
   (1) At record date.
   (2) At offering date.
   (3) One month after close of offering.
m. Average market price during offering.
   (1) Price per share.
   (2) Rights per share—average value of rights.
n. Latest reported earning per share at time of offering.
o. Latest reported dividends at time of offering."

RESPONSE:

The only public issuance of common stock by FirstEnergy Corp. since January 1, 2009 involved the exchange of 113,381,030 shares in connection with the Allegheny Energy merger. The dollar amount of the equity issued was $4,326,620,111.82 and was based on the closing price of FirstEnergy stock on February 24, 2011, the day before the effective date of the merger, of $38.16 per share.

In the 4th Quarter of 2013, FirstEnergy started issuing shares under the Stock Investment Plan (SIP), Divided Re-Investment Plan (DRIP), and certain Human Resources benefit programs that will provide approximately $75 mm per year of additional equity.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-E-1:

"If a claim of the filing utility is based on utilization of the capital structure or capital costs of the parent company and system – consolidated - the reasons for this claim must be fully stated and supported."

RESPONSE:

Not applicable.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-E-2:

"Regardless of the claim made, provide the capitalization data requested at Item III.A.2. for the parent company and for the system - consolidated."

RESPONSE:

See ME Exhibit SRS-14 Attachment A.

FirstEnergy Corp (Stand Alone/Parent)
Capitalization & Capitalization Ratios
($ Millions)

	Actuals	
	3/31/2013	3/31/2014
Capitalization		
Long Term Debt	3,213	4,231
Preferred Stock		
Common Equity	12,986	12,434
Total	16,199	16,665
Short-term Debt	2,507	1,499
Total	18,706	18,164
Capitalization Ratios		
Long Term Debt	19.8%	25.4%
Preferred Stock	0.0%	0.0%
Common Equity	80.2%	74.6%
Total	100.0%	100.0%
Long term Debt	17.2%	23.3%
Preferred Stock	0.0%	0.0%
Common Equity	69.4%	68.5%
Short-term Debt	13.4%	8.3%
Total	100.0%	100.0%

FirstEnergy Corp (Consolidated)
Capitalization & Capitalization Ratios
($ Millions)

	Actuals 3/31/2013	3/31/2014
Capitalization		
Long Term Debt	18,110	18,220
Preferred Stock		
Common Equity	12,996	12,605
Total	31,106	30,825
Short-term Debt	2,150	3,085
Total	33,256	33,910
Capitalization Ratios		
Long Term Debt	58.2%	59.1%
Preferred Stock	0.0%	0.0%
Common Equity	41.8%	40.9%
Total	100.0%	100.0%
Long term Debt	54.5%	53.7%
Preferred Stock	0.0%	0.0%
Common Equity	39.1%	37.2%
Short-term Debt	6.5%	9.1%
Total	100.0%	100.0%

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-E-3:

"Provide the latest available balance sheet and income statement for the parent company and system – consolidated."

RESPONSE:

See ME Exhibit SRS-15 Attachment A.

FE 10-Q 3/31/2014

Exhibit ME SRS-15
Attachment A
Witness: S.R. Staub

Section 1: 10-Q (10-Q)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q
(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2014

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____ to _____

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
333-21011	FIRSTENERGY CORP. (An Ohio Corporation) 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-1843785
000-53742	FIRSTENERGY SOLUTIONS CORP. (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	31-1560186

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No ☐ FirstEnergy Corp. and FirstEnergy Solutions Corp.

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ☑ No ☐ FirstEnergy Corp. and FirstEnergy Solutions Corp.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☑ FirstEnergy Corp.

Accelerated Filer ☐ N/A

Non-accelerated Filer (Do not check if a smaller reporting company) ☑	FirstEnergy Solutions Corp.
Smaller Reporting Company ☐	N/A

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☑ FirstEnergy Corp. and FirstEnergy Solutions Corp.

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

CLASS	OUTSTANDING AS OF APRIL 30, 2014
FirstEnergy Corp., $0.10 par value	419,908,686
FirstEnergy Solutions Corp., no par value	7

FirstEnergy Corp. is the sole holder of FirstEnergy Solutions Corp. common stock.

This combined Form 10-Q is separately filed by FirstEnergy Corp. and FirstEnergy Solutions Corp. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. No registrant makes any representation as to information relating to the other registrant, except that information relating to FirstEnergy Solutions Corp. is also attributed to FirstEnergy Corp.

FirstEnergy Web Site and Other Social Media Sites and Applications

Each of the registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are also made available free of charge on or through the "Investors" page of FirstEnergy's Internet web site at www.firstenergycorp.com.

These SEC filings are posted on the web site as soon as reasonably practicable after they are electronically filed with the SEC. Additionally, the registrants routinely post additional important information including press releases, investor presentations and notices of upcoming events, under the "Investors" section of FirstEnergy's Internet web site and recognize FirstEnergy's Internet web site as a channel of distribution to reach public investors and as a means of disclosing material non-public information for complying with disclosure obligations under SEC Regulation FD. Investors may be notified of postings to the web site by signing up for email alerts and RSS feeds on the "Investors" page of FirstEnergy's Internet web site or through push alerts from FirstEnergy Investor Relations apps for Apple Inc.'s iPad® and iPhone® devices, which can be installed for free at the Apple® online store. FirstEnergy also uses Twitter® and Facebook® as additional channels of distribution to reach public investors and as a supplemental means of disclosing material non-public information for complying with its disclosure obligations under SEC Regulation FD. Information contained on FirstEnergy's Internet web site or its Twitter® or Facebook® site, and any corresponding applications of those sites, shall not be deemed incorporated into, or to be part of, this report.

OMISSION OF CERTAIN INFORMATION

FirstEnergy Solutions Corp. meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to Form 10-Q.

Forward-Looking Statements: This Form 10-Q includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms “anticipate,” “potential,” “expect,” "will," "intend," “believe,” “estimate” and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements, which may include the following:

- The speed and nature of increased competition in the electric utility industry, in general, and the retail sales market in particular.
- The ability to experience growth in the Regulated Distribution and Regulated Transmission segments and to continue to successfully implement our direct retail sales strategy in the Competitive Energy Services segment.
- The accomplishment of our regulatory and operational goals in connection with our transmission plan and planned distribution rate cases and the effectiveness of our repositioning strategy.
- The impact of the regulatory process on the pending matters before FERC and in the various states in which we do business including, but not limited to, matters related to rates and pending rate cases.
- The uncertainties of various cost recovery and cost allocation issues resulting from ATSI's realignment into PJM.
- Economic or weather conditions affecting future sales and margins such as the polar vortex or other significant weather events.
- Regulatory outcomes associated with storm restoration, including but not limited to, Hurricane Sandy, Hurricane Irene and the October snowstorm of 2011.
- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil, and their availability and impact on retail margins.
- The continued ability of our regulated utilities to recover their costs.
- Costs being higher than anticipated and the success of our policies to control costs and to mitigate low energy, capacity and market prices.
- Other legislative and regulatory changes, and revised environmental requirements, including, but not limited to, possible GHG emission, water discharge, water intake and CCR regulations, the potential impacts of CSAPR, and the effects of the EPA's MATS rules including our estimated costs of compliance.
- The uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation, including NSR litigation or potential regulatory initiatives or rulemakings (including that such expenditures could result in our decision to deactivate or idle certain generating units).
- The uncertainties associated with the deactivation of certain older regulated and competitive fossil units including the impact on vendor commitments, and the timing thereof as they relate to, among other things, RMR arrangements and the reliability of the transmission grid.
- Adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to the revocation or non-renewal of necessary licenses, approvals or operating permits by the NRC or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant).
- Issues arising from the indications of cracking in the shield building and the steam generator replacement at Davis-Besse.
- The impact of future changes to the operational status or availability of our generating units.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.
- Replacement power costs being higher than anticipated or not fully hedged.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- Changes in customers' demand for power, including but not limited to, changes resulting from the implementation of state and federal energy efficiency and peak demand reduction mandates.
- The ability to accomplish or realize anticipated benefits from strategic and financial goals including, but not limited to, the ability to reduce costs and to successfully complete our announced financial plans designed to improve our credit metrics and strengthen our balance sheet, including but not limited to, our announced dividend reduction and our proposed capital raising and debt reduction initiatives.
- Our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel transportation on such margins.
- Changing market conditions that could affect the measurement of certain liabilities and the value of assets held in our NDTs, pension trusts and other trust funds, and cause us and our subsidiaries to make additional contributions sooner, or in amounts that are larger than currently anticipated.
- The impact of changes to material accounting policies.
- The ability to access the public securities and other capital and credit markets in accordance with our announced financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.
- Actions that may be taken by credit rating agencies that could negatively affect us and our subsidiaries' access to financing, increase the costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- Changes in national and regional economic conditions affecting us, our subsidiaries and our major industrial and commercial customers, and other counterparties including fuel suppliers, with which we do business.

- The impact of any changes in tax laws or regulations or adverse tax audit results or rulings.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks and other factors discussed from time to time in our SEC filings, and other similar factors.

Dividends declared from time to time on FE's common stock during any period may in the aggregate vary from prior periods due to circumstances considered by FE's Board of Directors at the time of the actual declarations. A security rating is not a recommendation to buy or hold securities and is subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

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GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this report to identify FirstEnergy Corp. and its current and former subsidiaries:

AE	Allegheny Energy, Inc., a Maryland utility holding company that merged with a subsidiary of FirstEnergy on February 25, 2011. As of January 1, 2014, AE merged with and into FirstEnergy Corp.
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary
AGC	Allegheny Generating Company, a generation subsidiary of AE Supply
ATSI	American Transmission Systems, Incorporated, formerly a direct subsidiary of FE that became a subsidiary of FET in April 2012, which owns and operates transmission facilities.
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
FE	FirstEnergy Corp., a public utility holding company
FELHC	FirstEnergy License Holding Company, Inc.
FENOC	FirstEnergy Nuclear Operating Company, which operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., which provides energy-related products and services
FESC	FirstEnergy Service Company, which provides legal, financial and other corporate support services
FET	FirstEnergy Transmission, LLC, formerly known as Allegheny Energy Transmission, LLC which is the parent of ATSI and TrAIL and has a joint venture in PATH.
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FG	FirstEnergy Generation, LLC, a subsidiary of FES, which owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., together with its consolidated subsidiaries
Global Holding	Global Mining Holding Company, LLC, a joint venture between FEV, WMB Marketing Ventures, LLC and Pinesdale LLC
Global Rail	A subsidiary of Global Holding that owns coal transportation operations near Roundup, Montana
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
ME	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MP	Monongahela Power Company, a West Virginia electric utility operating subsidiary
NG	FirstEnergy Nuclear Generation, LLC, a subsidiary of FES, which owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
PATH	Potomac-Appalachian Transmission Highline, LLC, a joint venture between FE and a subsidiary of AEP
PATH-Allegheny	PATH Allegheny Transmission Company, LLC
PATH-WV	PATH West Virginia Transmission Company, LLC
PE	The Potomac Edison Company, a Maryland electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	ME, PN, Penn and WP
PN	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Signal Peak	An indirect subsidiary of Global Holding that owns mining operations near Roundup, Montana
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TrAIL	Trans-Allegheny Interstate Line Company, a subsidiary of FET, which owns and operates transmission facilities
Utilities	OE, CEI, TE, Penn, JCP&L, ME, PN, MP, PE and WP
WP	West Penn Power Company, a Pennsylvania electric utility operating subsidiary

The following abbreviations and acronyms are used to identify frequently used terms in this report:

AEP	American Electric Power Company, Inc.
AFS	Available-for-sale
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
Anker WV	Anker West Virginia Mining Company, Inc.
Anker Coal	Anker Coal Group, Inc.
AOCI	Accumulated Other Comprehensive Income
Apple®	Apple®, iPad® and iPhone® are registered trademarks of Apple Inc.
ARO	Asset Retirement Obligation
ARR	Auction Revenue Right

GLOSSARY OF TERMS, *Continued*

ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CBA	Collective Bargaining Agreement
CBP	Competitive Bid Process
CCB	Coal Combustion By-products
CCR	Coal Combustion Residuals
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
Dayton	The Dayton Power and Light Company
DCR	Delivery Capital Recovery
DSP	Default Service Plan
Duke	Duke Energy Ohio, a subsidiary of Duke Energy Corporation
EDC	Electric Distribution Company
EDU	Electric Distribution Utility
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
ELPC	Environmental Law & Policy Center
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
ERO	Electric Reliability Organization
ESP	Electric Security Plan
Facebook®	Facebook is a registered trademark of Facebook, Inc.
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
FMB	First Mortgage Bond
FPA	Federal Power Act
FTR	Financial Transmission Right
GAAP	Accounting Principles Generally Accepted in the United States of America
GHG	Greenhouse Gases
GWH	Gigawatt-hour
HCL	Hydrochloric Acid
ICE	IntercontinentalExchange, Inc.
ICG	International Coal Group Inc.
kV	Kilovolt
KWH	Kilowatt-hour
LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LOC	Letter of Credit
LSE	Load Serving Entity
MAAC	Mid-Atlantic Region of PJM
MATS	Mercury and Air Toxics Standards
MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.
mmBTU	One Million British Thermal Units

GLOSSARY OF TERMS, *Continued*

Moody's	Moody's Investors Service, Inc.
MOPR	Minimum Offer Price Rule
MVP	Multi-value Project
MW	Megawatt
MWH	Megawatt-hour
NDT	Nuclear Decommissioning Trust
NERC	North American Electric Reliability Corporation
NGO	Non-Governmental Organization
NITS	Network Integration Transmission System
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NNSR	Non-Attainment New Source Review
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NYISO	New York Independent System Operator
NYPSC	New York State Public Service Commission
OCA	Office of Consumer Advocate
OCC	Ohio Consumers' Counsel
OPEB	Other Post-Employment Benefits
OTTI	Other Than Temporary Impairments
PA DEP	Pennsylvania Department of Environmental Protection
PCRB	Pollution Control Revenue Bond
Pennsylvania Industrials	ME Industrial Users Group and PN Industrial Customer Alliance
PJM	PJM Interconnection LLC
PM	Particulate Matter
POLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
REIT	Real Estate Investment Trust
RFC	Reliability*First* Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
RPM	Reliability Pricing Model
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SB221	Amended Substitute Senate Bill 221
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission

GLOSSARY OF TERMS, *Continued*

SERTP	Southeastern Regional Transmission Planning
SIP	State Implementation Plan(s) Under the Clean Air Act
SMIP	Smart Meter Implementation Plan
SO_2	Sulfur Dioxide
SOS	Standard Offer Service
SPE	Special Purpose Entity
SREC	Solar Renewable Energy Credit
SSO	Standard Service Offer
TDS	Total Dissolved Solid
TMDL	Total Maximum Daily Load
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
Twitter®	Twitter is a registered trademark of Twitter, Inc.
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
UWUA	Utility Workers Union of America
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission
WVCAG	West Virginia Citizen Action Group
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

PART I. FINANCIAL INFORMATION

ITEM I. Financial Statements

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended March 31	
(In millions, except per share amounts)	2014	2013
REVENUES:		
Electric utilities	$ 2,739	$ 2,388
Unregulated businesses	1,450	1,335
Total revenues*	4,189	3,723
OPERATING EXPENSES:		
Fuel	617	630
Purchased power	1,455	946
Other operating expenses	1,182	882
Provision for depreciation	294	293
Amortization (deferral) of regulatory assets, net	(28)	59
General taxes	271	265
Total operating expenses	3,791	3,075
OPERATING INCOME	398	648
OTHER INCOME (EXPENSE):		
Loss on debt redemptions	(7)	(117)
Investment income	22	18
Interest expense	(265)	(258)
Capitalized interest	22	15
Total other expense	(228)	(342)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	170	306
INCOME TAXES	48	114
INCOME FROM CONTINUING OPERATIONS	122	192
Discontinued operations (net of income taxes of $69 and $2, respectively) (Note 13)	86	4
NET INCOME	$ 208	$ 196
EARNINGS PER SHARE OF COMMON STOCK:		
Basic - Continuing Operations	$ 0.29	$ 0.46
Basic - Discontinued Operations (Note 13)	0.21	0.01
Basic - Net Earnings per Basic Share	$ 0.50	$ 0.47
Diluted - Continuing Operations	$ 0.29	$ 0.46
Diluted - Discontinued Operations (Note 13)	0.20	0.01
Diluted - Net Earnings per Diluted Share	$ 0.49	$ 0.47
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:		
Basic	419	418
Diluted	420	419
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK**	$ 0.72	$ 0.55

* Includes excise tax collections of $117 million and $122 million in the three months ended March 31, 2014 and 2013, respectively.

** The three months ended March 31, 2014 includes a dividend declared of $0.36 per share on January 21, 2014, paid on March 1, 2014 and a dividend declared of $0.36 per share on March 18, 2014, payable June 1, 2014. The three months ended March 31, 2013 includes a dividend declared of $0.55 per share on March 19, 2013, paid on June 1, 2013.

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended March 31 2014	2013
NET INCOME	$ 208	$ 196
OTHER COMPREHENSIVE INCOME (LOSS):		
Pensions and OPEB prior service costs	(42)	(46)
Amortized losses on derivative hedges	—	1
Change in unrealized gain on available-for-sale securities	21	5
Other comprehensive loss	(21)	(40)
Income tax benefits on other comprehensive loss	(8)	(16)
Other comprehensive loss, net of tax	(13)	(24)
COMPREHENSIVE INCOME	$ 195	$ 172

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	March 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 109	$ 218
Receivables-		
Customers, net of allowance for uncollectible accounts of $55 in 2014 and $52 in 2013	1,869	1,720
Other, net of allowance for uncollectible accounts of $3 in 2014 and 2013	218	198
Materials and supplies, at average cost	740	752
Prepaid taxes	240	226
Derivatives	247	166
Accumulated deferred income taxes	375	366
Collateral	580	155
Other	199	212
	4,577	4,013
PROPERTY, PLANT AND EQUIPMENT:		
In service	44,782	44,228
Less — Accumulated provision for depreciation	13,555	13,280
	31,227	30,948
Construction work in progress	2,661	2,304
	33,888	33,252
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,263	2,201
Other	898	903
	3,161	3,104
ASSETS HELD FOR SALE	—	235
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,418	6,418
Regulatory assets	1,798	1,854
Other	1,386	1,548
	9,602	9,820
	$ 51,228	$ 50,424
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,416	$ 1,415
Short-term borrowings	3,085	3,404
Accounts payable	1,455	1,250
Accrued taxes	527	485
Accrued compensation and benefits	232	351
Derivatives	159	111
Other	863	621
	7,737	7,637
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 419,837,287 shares and 418,628,559 shares outstanding as of March 31, 2014 and December 31, 2013, respectively	42	42
Other paid-in capital	9,793	9,776
Accumulated other comprehensive income	271	284

Retained earnings	2,496	2,590
Total common stockholders' equity	12,602	12,692
Noncontrolling interest	3	3
Total equity	12,605	12,695
Long-term debt and other long-term obligations	16,804	15,831
	29,409	28,526
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	7,028	6,968
Retirement benefits	2,713	2,689
Asset retirement obligations	1,704	1,678
Deferred gain on sale and leaseback transaction	850	858
Adverse power contract liability	255	290
Other	1,532	1,778
	14,082	14,261
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$ 51,228	$ 50,424

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31	
(In millions)	**2014**	**2013**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 208	$ 196
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	294	293
Amortization (deferral) of regulatory assets, net	(28)	59
Nuclear fuel amortization	48	53
Deferred purchased power and other costs	(34)	(25)
Deferred income taxes and investment tax credits, net	181	134
Deferred rents and lease market valuation liability	33	37
Retirement benefits	(20)	(64)
Commodity derivative transactions, net (Note 8)	(17)	4
Loss on debt redemptions	7	117
Income from discontinued operations (Note 13)	(86)	(4)
Changes in current assets and liabilities-		
Receivables	(168)	(34)
Materials and supplies	12	26
Prepayments and other current assets	(29)	(159)
Accounts payable	200	(378)
Accrued taxes	(242)	(128)
Accrued interest	46	53
Accrued compensation and benefits	(118)	(91)
Cash collateral, net	(461)	(1)
Other	82	(38)
Net cash (used for) provided from operating activities	(92)	50
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	1,467	1,800
Short-term borrowings, net	—	181
Redemptions and Repayments-		
Long-term debt	(489)	(846)
Short-term borrowings, net	(319)	—
Tender premiums paid on debt redemptions	—	(110)
Common stock dividend payments	(151)	(230)
Other	(10)	(23)
Net cash provided from financing activities	498	772
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(821)	(826)
Nuclear fuel	(55)	(27)
Proceeds from asset sales	394	—
Sales of investment securities held in trusts	621	539
Purchases of investment securities held in trusts	(646)	(565)
Cash investments	28	6
Asset removal costs	(39)	(53)
Other	3	(1)

Net cash used for investing activities	(515)	(927)
Net change in cash and cash equivalents	(109)	(105)
Cash and cash equivalents at beginning of period	218	172
Cash and cash equivalents at end of period	$ 109	$ 67

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended March 31 2014	2013
STATEMENTS OF INCOME		
REVENUES:		
Electric sales to non-affiliates	$ 1,440	$ 1,334
Electric sales to affiliates	349	156
Other	40	34
Total revenues	1,829	1,524
OPERATING EXPENSES:		
Fuel	319	300
Purchased power from affiliates	64	132
Purchased power from non-affiliates	1,029	506
Other operating expenses	452	379
Provision for depreciation	74	75
General taxes	39	37
Total operating expenses	1,977	1,429
OPERATING INCOME (LOSS)	(148)	95
OTHER INCOME (EXPENSE):		
Loss on debt redemptions	(5)	(71)
Investment income	20	17
Miscellaneous income	—	2
Interest expense — affiliates	(2)	(1)
Interest expense — other	(36)	(52)
Capitalized interest	12	9
Total other expense	(11)	(96)
LOSS FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(159)	(1)
INCOME TAX BENEFITS	(56)	—
LOSS FROM CONTINUING OPERATIONS	(103)	(1)
Discontinued operations (net of income taxes of $70 and $2, respectively) (Note 13)	116	3
NET INCOME	$ 13	$ 2
STATEMENTS OF COMPREHENSIVE INCOME		
NET INCOME	$ 13	$ 2
OTHER COMPREHENSIVE INCOME (LOSS):		
Pensions and OPEB prior service costs	(5)	(6)
Amortized loss on derivative hedges	(2)	(1)
Change in unrealized gain on available-for-sale securities	19	5
Other comprehensive income (loss)	12	(2)

Income taxes (benefits) on other comprehensive income (loss)	4	(1)
Other comprehensive income (loss), net of tax	8	(1)
COMPREHENSIVE INCOME	$ 21	$ 1

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	March 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2	$ 2
Receivables-		
Customers, net of allowance for uncollectible accounts of $13 in 2014 and $11 in 2013	583	539
Affiliated companies	369	1,036
Other, net of allowance for uncollectible accounts of $3 in 2014 and 2013	151	81
Notes receivable from affiliated companies	215	—
Materials and supplies	427	448
Derivatives	244	165
Collateral	544	136
Prepayments and other	179	109
	2,714	2,516
PROPERTY, PLANT AND EQUIPMENT:		
In service	12,796	12,472
Less — Accumulated provision for depreciation	4,857	4,755
	7,939	7,717
Construction work in progress	1,356	1,308
	9,295	9,025
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,323	1,276
Other	11	11
	1,334	1,287
ASSETS HELD FOR SALE	—	122
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	91	95
Goodwill	23	23
Property taxes	30	41
Unamortized sale and leaseback costs	197	168
Derivatives	65	53
Other	150	172
	556	552
	$ 13,899	$ 13,502
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 465	$ 892
Short-term borrowings-		
Affiliated companies	—	431
Other	555	4
Accounts payable-		
Affiliated companies	327	765
Other	295	290
Accrued taxes	97	66
Derivatives	159	110
Other	214	197
	2,112	2,755

CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares- 7 shares outstanding as of March 31, 2014 and December 31, 2013	3,580	3,080
Accumulated other comprehensive income	62	54
Retained earnings	2,191	2,178
Total common stockholder's equity	5,833	5,312
Long-term debt and other long-term obligations	2,551	2,130
	8,384	7,442
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	850	858
Accumulated deferred income taxes	810	741
Asset retirement obligations	1,029	1,015
Retirement benefits	189	185
Derivatives	36	14
Other	489	492
	3,403	3,305
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$ 13,899	$ 13,502

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 13	$ 2
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	74	75
Nuclear fuel amortization	48	53
Deferred rents and lease market valuation liability	21	21
Deferred income taxes and investment tax credits, net	48	56
Commodity derivative transactions, net (Note 8)	(17)	3
Loss on debt redemptions	5	71
Income from discontinued operations (Note 13)	(116)	(3)
Changes in current assets and liabilities-		
Receivables	553	(177)
Materials and supplies	21	28
Prepayments and other current assets	(48)	(55)
Accounts payable	(430)	(185)
Accrued taxes	(49)	(80)
Accrued compensation and benefits	(19)	(16)
Cash collateral, net	(420)	38
Other	4	(26)
Net cash used for operating activities	(312)	(195)
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	417	—
Short-term borrowings, net	120	702
Equity contribution from parent	500	—
Redemptions and repayments-		
Long-term debt	(445)	(476)
Tender premiums paid on debt redemptions	—	(67)
Other	(4)	(1)
Net cash provided from financing activities	588	158
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(298)	(217)
Nuclear fuel	(55)	(27)
Proceeds from asset sales	307	17
Sales of investment securities held in trusts	423	252
Purchases of investment securities held in trusts	(438)	(265)
Loans to affiliated companies, net	(215)	276
Other	—	1
Net cash (used for) provided from investing activities	(276)	37
Net change in cash and cash equivalents	—	—
Cash and cash equivalents at beginning of period	2	3
Cash and cash equivalents at end of period	$ 2	$ 3

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

Unless otherwise indicated, defined terms and abbreviations used herein have the meanings set forth in the accompanying Glossary of Terms.

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. FirstEnergy's principal business is the holding, directly or indirectly, of all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FESC, FES and its principal subsidiaries (FG and NG), AE Supply, MP, PE, WP and FET. In addition, FirstEnergy holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., and GPU Nuclear, Inc.

These interim financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and disclosures normally included in financial statements and notes prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations. These interim financial statements should be read in conjunction with the financial statements and notes included in the combined Annual Report on Form 10-K for the year ended December 31, 2013.

FirstEnergy follows GAAP and complies with the related regulations, orders, policies and practices prescribed by the SEC, FERC, and, as applicable, the PUCO, the PPUC, the MDPSC, the NYPSC, the WVPSC, the VSCC and the NJBPU. The accompanying interim financial statements are unaudited, but reflect all adjustments, consisting of normal recurring adjustments, that, in the opinion of management, are necessary for a fair statement of the financial statements. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not indicative of results of operations for any future period. FE and its subsidiaries have evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued.

FE and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary (see Note 6, Variable Interest Entities). Investments in affiliates over which FE and its subsidiaries have the ability to exercise significant influence, but with respect to which they are not the primary beneficiary and do not exercise control, follow the equity method of accounting. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity's earnings is reported in the Consolidated Statements of Income and Comprehensive Income. These Notes to the Consolidated Financial Statements are combined for FirstEnergy and FES.

Certain prior year amounts have been reclassified to conform to the current year presentation. These reclassifications include, but are not limited to, the classification of discontinued operations associated with our sale of hydro assets discussed in additional detail in Note 13, Discontinued Operations.

New Accounting Pronouncements

New accounting pronouncements not yet effective are not expected to have a material effect on the financial statements of FE or its subsidiaries.

2. EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share of common stock are computed using the weighted average number of common shares outstanding during the relevant period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised.

The following table reconciles basic and diluted earnings per share of common stock:

(In millions, except per share amounts)	Three Months Ended March 31	
Reconciliation of Basic and Diluted Earnings per Share of Common Stock	**2014**	**2013**
Income from continuing operations	$ 122	$ 192
Discontinued operations (Note 13)	86	4
Net income	$ 208	$ 196
Weighted average number of basic shares outstanding	419	418
Assumed exercise of dilutive stock options and awards[(1)]	1	1
Weighted average number of diluted shares outstanding	420	419
Earnings per share:		
Basic earnings per share:		
Income from continuing operations	$ 0.29	$ 0.46
Discontinued operations (Note 13)	0.21	0.01
Net earnings per basic share	$ 0.50	$ 0.47
Diluted earnings per share:		
Income from continuing operations	$ 0.29	$ 0.46
Discontinued operations (Note 13)	0.20	0.01
Net earnings per diluted share	$ 0.49	$ 0.47

(1) For the three months ended March 31, 2014, 2 million shares were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive. The number of potentially dilutive securities not included in the calculation of diluted shares outstanding due to their antidilutive effect was not significant for the three months ended March 31, 2013.

3. PENSIONS AND OTHER POSTEMPLOYMENT BENEFITS

The components of the consolidated net periodic cost (credits) for pensions and OPEB (including amounts capitalized) were as follows:

Components of Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Three Months Ended March 31,	2014	2013	2014	2013
		(In millions)		
Service costs	$ 42	$ 49	$ 2	$ 3
Interest costs	100	93	10	9
Expected return on plan assets	(115)	(125)	(8)	(8)
Amortization of prior service costs (credits)	2	3	(44)	(50)
Net periodic costs (credits)	$ 29	$ 20	$ (40)	$ (46)

FES' share of the net periodic pensions and OPEB costs (credits) were as follows:

	Pensions		OPEB	
For the Three Months Ended March 31,	2014	2013	2014	2013
		(In millions)		
Net Periodic Costs	$ 4	$ 5	$ (5)	$ (5)

Pension and OPEB obligations are allocated to FE's subsidiaries employing the plan participants. The net periodic pension and OPEB costs (net of amounts capitalized) recognized in earnings by FE and FES were as follows:

Net Periodic Benefit Expense (Credit)	Pensions		OPEB	
For the Three Months Ended March 31,	2014	2013	2014	2013
		(In millions)		
FirstEnergy	$ 21	$ 11	$ (27)	$ (30)
FES	4	3	(4)	(3)

4. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, in the three months ended March 31, 2014 and 2013, for FirstEnergy and FES are shown in the following tables:

FirstEnergy

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
		(In millions)		
AOCI Balance as of January 1, 2014	$ (36)	$ 9	$ 311	$ 284
Other comprehensive income before reclassifications	—	22	—	22
Amounts reclassified from AOCI	—	(9)	(26)	(35)
Net other comprehensive income (loss)	—	13	(26)	(13)
AOCI Balance as of March 31, 2014	$ (36)	$ 22	$ 285	$ 271
AOCI Balance as of January 1, 2013	$ (38)	$ 15	$ 408	$ 385
Other comprehensive income before reclassifications	—	15	—	15
Amounts reclassified from AOCI	1	(12)	(28)	(39)
Net other comprehensive income (loss)	1	3	(28)	(24)
AOCI Balance as of March 31, 2013	$ (37)	$ 18	$ 380	$ 361

FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
		(In millions)		
AOCI Balance as of January 1, 2014	$ (1)	$ 8	$ 47	$ 54
Other comprehensive income before reclassifications	—	21	—	21
Amounts reclassified from AOCI	(1)	(9)	(3)	(13)
Net other comprehensive income (loss)	(1)	12	(3)	8
AOCI Balance as of March 31, 2014	$ (2)	$ 20	$ 44	$ 62
AOCI Balance as of January 1, 2013	$ 3	$ 13	$ 56	$ 72
Other comprehensive income before reclassifications	—	14	—	14
Amounts reclassified from AOCI	(1)	(10)	(4)	(15)
Net other comprehensive income (loss)	(1)	4	(4)	(1)
AOCI Balance as of March 31, 2013	$ 2	$ 17	$ 52	$ 71

The following amounts were reclassified from AOCI in the three months ended March 31, 2014 and 2013:

FE	Three Months Ended March 31		
Reclassifications from AOCI (b)	2014	2013	Affected Line Item in Consolidated Statements of Income
	(In millions)		
Gains & losses on cash flow hedges			
Commodity contracts	$ (2)	$ (3)	Other operating expenses
Long-term debt	2	4	Interest expense ($2) in 2014 and Interest expense ($2) and loss on debt redemptions ($2) in 2013
	—	1	Total before taxes
	—	—	Income taxes
	$ —	$ 1	Net of tax
Unrealized gains on AFS securities			
Realized gains on sales of securities	$ (14)	$ (19)	Investment income
	5	7	Income taxes
	$ (9)	$ (12)	Net of tax
Defined benefit pension and OPEB plans			
Prior-service costs	$ (42)	$ (47)	(a)
	16	19	Income taxes
	$ (26)	$ (28)	Net of tax

(a) These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pensions and Other Postemployment Benefits for additional details.

(b) Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

FES	Three Months Ended March 31		
Reclassifications from AOCI (b)	2014	2013	Affected Line Item in Consolidated Statements of Income
	(In millions)		
Gains & losses on cash flow hedges			
Commodity contracts	$ (2)	$ (3)	Other operating expenses
Long-term debt	—	2	Loss on debt redemptions
	(2)	(1)	Total before taxes
	1	—	Income tax benefits
	$ (1)	$ (1)	Net of tax
Unrealized gains on AFS securities			
Realized gains on sales of securities	$ (14)	$ (16)	Investment income
	5	6	Income tax benefits
	$ (9)	$ (10)	Net of tax
Defined benefit pension and OPEB plans			
Prior-service costs	$ (5)	$ (5)	(a)
	2	1	Income tax benefits
	$ (3)	$ (4)	Net of tax

(a) These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pensions and Other Postemployment Benefits for additional details.

(b) Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

5. INCOME TAXES

FirstEnergy's and FES's interim effective tax rates reflect the estimated annual effective tax rates for 2014 and 2013, adjusted for tax expense associated with certain discrete items.

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. Significant judgment is required in determining FirstEnergy's income taxes and in evaluating tax positions taken or expected to be taken on its tax returns. There were no material changes to FirstEnergy's unrecognized income tax benefits during the first three months of 2014 or 2013.

As of March 31, 2014, it is reasonably possible that approximately $35 million of unrecognized income tax benefits, including interest, may be resolved within the next twelve months as a result of the statute of limitations expiring, all of which would affect FirstEnergy's effective tax rate.

FirstEnergy recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. During the first three months of 2014 and 2013, there were no material changes to the amount of accrued interest. The net amount of interest accrued as of March 31, 2014 and December 31, 2013 was approximately $9 million.

FirstEnergy's effective tax rate from continuing operations for the three months ended March 31, 2014 and 2013 was 28.2% and 37.2%, respectively. The decrease in the effective tax rate is primarily due to an increase in AFUDC equity flow through, changes in state apportionment factors and the elimination of certain future tax liabilities associated with basis differences.

FES's effective tax rate from continuing operations for the three months ended March 31, 2014 and 2013 was 35.2% and 24.8%, respectively. The increase in the effective tax rate is primarily related to the impact of permanent tax adjustments on estimated annual pretax earnings from continuing operations.

In April 2014, the Internal Revenue Service completed its examination of FE's 2011 and 2012 federal income tax returns and issued Revenue Agent Reports for these years.

6. VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses to determine whether a variable interest gives FirstEnergy a controlling financial interest in a VIE. This analysis identifies the primary beneficiary of a VIE as the enterprise that has both the power to direct the activities of a VIE that most significantly impact the entity's economic performance and the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE. FirstEnergy consolidates a VIE when it is determined that it is the primary beneficiary.

VIEs included in FirstEnergy's consolidated financial statements are: the PNBV capital trusts that were created to refinance debt originally issued in connection with sale and leaseback transactions; wholly-owned limited liability companies of the Ohio Companies (as described below); wholly owned limited liability companies of JCP&L created to sell transition bonds to securitize the recovery of JCP&L's bondable stranded costs and special purpose limited liability companies created to issue environmental control bonds that were used to construct environmental control facilities.

The caption "noncontrolling interest" within the consolidated financial statements is used to reflect the portion of a VIE that FirstEnergy consolidates, but does not own.

In order to evaluate contracts for consolidation treatment and entities for which FirstEnergy has an interest, FirstEnergy aggregates variable interests into the following categories based on similar risk characteristics and significance.

Ohio Securitization

In September 2012, the Ohio Companies formed CEI Funding LLC, OE Funding LLC and TE Funding LLC, respectively, as separate, wholly-owned limited liability SPEs. Each SPE is a bankruptcy-remote, special purpose limited liability company that is restricted to activities necessary to issue phase-in recovery bonds and perform other functions in connection with the bond issuance. Creditors of FirstEnergy and the Ohio Companies have no recourse to any assets or revenues of the SPEs. The phase-in recovery bonds issued by these SPEs are payable only from, and secured by, phase-in recovery property held by the SPEs (i.e. the right to impose, charge and collect irrevocable non-bypassable usage-based charges payable by retail electric customers in the service territories of the Ohio Companies) and the bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. The SPEs are considered VIEs and each one is consolidated into its applicable utility.

Mining Operations

FEV holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations. FEV is not the primary beneficiary of the joint venture, as it does not have control over the significant activities affecting the joint venture's economic performance. FEV's ownership interest is subject to the equity method of accounting.

Trusts

FirstEnergy's consolidated financial statements include PNBV. FirstEnergy used debt and available funds to purchase the notes issued by PNBV for the purchase of lease obligation bonds. Ownership of PNBV includes a 3% equity interest by an unaffiliated third party and a 3% equity interest held by OES Ventures, a wholly owned subsidiary of OE.

PATH-WV

PATH is a series limited liability company that is comprised of multiple series, each of which has separate rights, powers and duties regarding specified property and the series profits and losses associated with such property. A subsidiary of FirstEnergy owns 100% of the Allegheny Series (PATH-Allegheny) and 50% of the West Virginia Series (PATH-WV), which is a joint venture with a subsidiary of AEP. FirstEnergy is not the primary beneficiary of PATH-WV, as it does not have control over the significant activities affecting the economics of the portion of the PATH project that was to be constructed by PATH-WV.

On August 24, 2012, PJM removed the PATH project from its long-range expansion plans. See Note 9, Regulatory Matters, for additional information on the abandonment of PATH.

Power Purchase Agreements

FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities at its Regulated Distribution segment may be VIEs to the extent that they own a plant that sells substantially all of its output to the applicable utilities and the contract price for power is correlated with the plant's variable costs of production. FirstEnergy maintains 20 long-term power purchase agreements with NUG entities that were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities.

FirstEnergy has determined that for all but two of these NUG entities, it does not have variable interests in the entities or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold variable interests in the remaining two entities; however, it applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

Because FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred at its Regulated Distribution segment to be recovered from customers. Purchased power costs related to the contracts that may contain a variable interest were $61 million and $49 million during the three months ended March 31, 2014 and 2013, respectively.

Sale and Leaseback

FirstEnergy has variable interests in certain sale and leaseback transactions. FirstEnergy is not the primary beneficiary of these interests as it does not have control over the significant activities affecting the economics of the arrangements.

In March of 2013, FG acquired the remaining interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for approximately $221 million. Also during 2013, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $23 million and in February 2014, NG purchased additional lessor equity interests for approximately $94 million.

FES, and other FE subsidiaries are exposed to losses under their applicable sale and leaseback agreements upon the occurrence of certain contingent events. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events. Net discounted lease payments would not be payable if the casualty loss payments were made. The following table discloses each company's net exposure to loss based upon the casualty value provisions as of March 31, 2014:

	Maximum Exposure	Discounted Lease Payments, net[1]	Net Exposure
		(In millions)	
FES	$ 1,293	$ 1,081	$ 212
Other FE subsidiaries	716	495	221

[1] The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is $1.1 billion.

7. FAIR VALUE MEASUREMENTS

RECURRING AND NONRECURRING FAIR VALUE MEASUREMENTS

Authoritative accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. The three levels of the fair value hierarchy and a description of the valuation techniques are as follows:

Level 1
- Quoted prices for identical instruments in active market

Level 2
- Quoted prices for similar instruments in active market
- Quoted prices for identical or similar instruments in markets that are not active
- Model-derived valuations for which all significant inputs are observable market data

Models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Level 3
- Valuation inputs are unobservable and significant to the fair value measurement

FirstEnergy produces a long-term power and capacity price forecast annually with periodic updates as market conditions change. When underlying prices are not observable, prices from the long-term price forecast, which has been reviewed and approved by FirstEnergy's Risk Policy Committee, are used to measure fair value. A more detailed description of FirstEnergy's valuation process for FTRs and NUGs are as follows:

FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly day-ahead congestion price differences across transmission paths. FTRs are acquired by FirstEnergy in the annual, monthly and long-term RTO auctions and are initially recorded using the auction clearing price less cost. After initial recognition, FTRs' carrying values are periodically adjusted to fair value using a mark-to-model methodology, which approximates market. The primary inputs into the model, which are generally less observable than objective sources, are the most recent RTO auction clearing prices and the FTRs' remaining hours. The model calculates the fair value by multiplying the most recent auction clearing price by the remaining FTR hours less the prorated FTR cost. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement. See Note 8, Derivative Instruments, for additional information regarding FirstEnergy's FTRs.

NUG contracts represent purchase power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. NUG contract carrying values are recorded at fair value and adjusted periodically using a mark-to-model methodology, which approximates market. The primary unobservable inputs into the model are regional power prices and generation MWH. Pricing for the NUG contracts is a combination of market prices for the current year and next three years based on observable data and internal models using historical trends and market data for the remaining years under contract. The internal models use forecasted energy purchase prices as an input when prices are not defined by the contract. Forecasted market prices are based on ICE quotes and management assumptions. Generation MWH reflects data provided by contractual arrangements and historical trends. The model calculates the fair value by multiplying the prices by the generation MWH. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement.

FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of March 31, 2014, from those used as of December 31, 2013. The determination of the fair value measures takes into consideration various factors, including but not limited to, nonperformance risk, counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of these forms of risk was not significant to the fair value measurements.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the three months ended March 31, 2014. The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:

FirstEnergy

Recurring Fair Value Measurements	March 31, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets				*(In millions)*				
Corporate debt securities	$ —	$ 1,168	$ —	$ 1,168	$ —	$ 1,365	$ —	$ 1,365
Derivative assets - commodity contracts	11	293	—	304	7	208	—	215
Derivative assets - FTRs	—	—	7	7	—	—	4	4
Derivative assets - NUG contracts[1]	—	—	3	3	—	—	20	20
Equity securities[2]	464	—	—	464	317	—	—	317
Foreign government debt securities	—	94	—	94	—	109	—	109
U.S. government debt securities	—	167	—	167	—	165	—	165
U.S. state debt securities	—	237	—	237	—	228	—	228
Other[3]	54	379	—	433	187	255	—	442
Total assets	$ 529	$ 2,338	$ 10	$ 2,877	$ 511	$ 2,330	$ 24	$ 2,865
Liabilities								
Derivative liabilities - commodity contracts	$ (8)	$ (179)	$ —	$ (187)	$ (13)	$ (100)	$ —	$ (113)
Derivative liabilities - FTRs	—	—	(8)	(8)	—	—	(12)	(12)
Derivative liabilities - NUG contracts[1]	—	—	(188)	(188)	—	—	(222)	(222)
Total liabilities	$ (8)	$ (179)	$ (196)	$ (383)	$ (13)	$ (100)	$ (234)	$ (347)
Net assets (liabilities)[4]	$ 521	$ 2,159	$ (186)	$ 2,494	$ 498	$ 2,230	$ (210)	$ 2,518

(1) NUG contracts are generally subject to regulatory accounting treatment and do not impact earnings.

(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.

(3) Primarily consists of short-term cash investments.

(4) Excludes $9 million and $10 million as of March 31, 2014 and December 31, 2013, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts, LCAPP contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended March 31, 2014 and December 31, 2013:

	NUG Contracts[1]			LCAPP Contracts[1]			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
					(In millions)				
January 1, 2013 Balance	$ 36	$ (290)	$ (254)	$ —	$ (144)	$ (144)	$ 8	$ (9)	$ (1)
Unrealized gain (loss)	(8)	(17)	(25)	—	(22)	(22)	3	1	4
Purchases	—	—	—	—	—	—	6	(15)	(9)
Terminations[2]	—	—	—	—	166	166	—	—	—
Settlements	(8)	85	77	—	—	—	(13)	11	(2)
December 31, 2013 Balance	$ 20	$ (222)	$ (202)	$ —	$ —	$ —	$ 4	$ (12)	$ (8)
Unrealized gain	—	27	27	—	—	—	6	2	8
Settlements	(17)	7	(10)	—	—	—	(3)	2	(1)
March 31, 2014 Balance	$ 3	$ (188)	$ (185)	$ —	$ —	$ —	$ 7	$ (8)	$ (1)

(1) Changes in the fair value of NUG and LCAPP contracts are generally subject to regulatory accounting treatment and do not impact earnings.
(2) See Note 8, Derivative Instruments

Level 3 Quantitative Information

The following table provides quantitative information for FTRs and NUG contracts that are classified as Level 3 in the fair value hierarchy for the period ended March 31, 2014:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (1)	Model	RTO auction clearing prices	($4.20) to $7.60	$0.80	Dollars/MWH
NUG Contracts	$ (185)	Model	Generation	600 to 5,422,000	1,033,000	MWH
			Electricity regional prices	$47.90 to $59.00	$53.50	Dollars/MWH

FES

Recurring Fair Value Measurements	March 31, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets				*(In millions)*				
Corporate debt securities	$ —	$ 586	$ —	$ 586	$ —	$ 792	$ —	$ 792
Derivative assets - commodity contracts	11	294	—	305	7	208	—	215
Derivative assets - FTRs	—	—	4	4	—	—	3	3
Equity securities[1]	327	—	—	327	207	—	—	207
Foreign government debt securities	—	55	—	55	—	65	—	65
U.S. government debt securities	—	25	—	25	—	27	—	27
U.S. state debt securities	—	3	—	3	—	—	—	—
Other[2]	—	319	—	319	—	176	—	176
Total assets	$ 338	$ 1,282	$ 4	$ 1,624	$ 214	$ 1,268	$ 3	$ 1,485
Liabilities								
Derivative liabilities - commodity contracts	$ (8)	$ (179)	$ —	$ (187)	$ (13)	$ (100)	$ —	$ (113)
Derivative liabilities - FTRs	—	—	(8)	(8)	—	—	(11)	(11)
Total liabilities	$ (8)	$ (179)	$ (8)	$ (195)	$ (13)	$ (100)	$ (11)	$ (124)
Net assets (liabilities)[3]	$ 330	$ 1,103	$ (4)	$ 1,429	$ 201	$ 1,168	$ (8)	$ 1,361

(1) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.

(2) Primarily consists of short-term cash investments.

(3) Excludes $8 million and $9 million as of March 31, 2014 and December 31, 2013, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the periods ended March 31, 2014 and December 31, 2013:

	Derivative Asset FTRs	Derivative Liability FTRs	Net FTRs
		(In millions)	
January 1, 2013 Balance	$ 6	$ (6)	$ —
Unrealized loss	—	(2)	(2)
Purchases	5	(12)	(7)
Settlements	(8)	9	1
December 31, 2013 Balance	$ 3	$ (11)	$ (8)
Unrealized gain	3	1	4
Settlements	(2)	2	—
March 31, 2014 Balance	$ 4	$ (8)	$ (4)

Level 3 Quantitative Information

The following table provides quantitative information for FTRs held by FES that are classified as Level 3 in the fair value hierarchy for the period ended March 31, 2014:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (4)	Model	RTO auction clearing prices	($4.20) to $7.60	$0.60	Dollars/MWH

INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities, AFS securities and notes receivable.

At the end of each reporting period, FirstEnergy evaluates its investments for OTTI. Investments classified as AFS securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold an equity security until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FirstEnergy considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Unrealized gains and losses on AFS securities are recognized in AOCI. However, unrealized losses held in the NDTs of FES, OE and TE are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI.

The investment policy for the NDT funds restricts or limits the trusts' ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, securities convertible into common stock and securities of the trust funds' custodian or managers and their parents or subsidiaries.

AFS Securities

FirstEnergy holds debt and equity securities within its NDT, nuclear fuel disposal and NUG trusts. These trust investments are considered AFS securities, recognized at fair market value. FirstEnergy has no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains (there were no unrealized losses) and fair values of investments held in NDT, nuclear fuel disposal and NUG trusts as of March 31, 2014 and December 31, 2013:

	March 31, 2014[1]			December 31, 2013[2]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
			(In millions)			
Debt securities						
FirstEnergy	$ 1,670	$ 44	$ 1,714	$ 1,881	$ 33	$ 1,914
FES	698	22	720	918	17	935
Equity securities						
FirstEnergy	$ 433	$ 31	$ 464	$ 308	$ 9	$ 317
FES	308	19	327	207	—	207

(1) Excludes short-term cash investments: FE Consolidated - $324 million; FES - $276 million.
(2) Excludes short-term cash investments: FE Consolidated - $204 million; FES - $135 million.

Proceeds from the sale of investments in AFS securities, realized gains and losses on those sales, OTTI and interest and dividend income for the three months ended March 31, 2014 and 2013 were as follows:

	Three Months Ended				
March 31, 2014	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
			(In millions)		
FirstEnergy	$ 621	$ 28	$ (16)	$ (2)	$ 25
FES	423	19	(5)	(2)	15
March 31, 2013	**Sale Proceeds**	**Realized Gains**	**Realized Losses**	**OTTI**	**Interest and Dividend Income**
			(In millions)		
FirstEnergy	$ 539	$ 24	$ (6)	$ (7)	$ 26
FES	252	20	(3)	(7)	13

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of March 31, 2014 and December 31, 2013:

	March 31, 2014			December 31, 2013		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
			(In millions)			
Debt Securities						
FirstEnergy	$ 24	$ 8	$ 32	$ 33	$ 2	$ 35

Investments in employee benefit trusts and cost and equity method investments, including FirstEnergy's investment in Global Holding, totaling $635 million as of March 31, 2014, and $636 million as of December 31, 2013, are excluded from the amounts reported above.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported as Short-term borrowings on the Consolidated Balance Sheets at cost. Since these borrowings are short-term in nature, FirstEnergy believes that their costs approximate their fair market value. The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations, excluding capital lease obligations and net unamortized premiums and discounts:

	March 31, 2014		December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
FirstEnergy	$ 18,034	$ 19,321	$ 17,049	$ 17,957
FES	2,996	3,098	3,001	3,073

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy and its subsidiaries. FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of March 31, 2014 and December 31, 2013.

On March 31, 2014, FE, FES, AE Supply, FET and FE's other borrower subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until March 31, 2019. The FE facility was amended to increase the lending banks' commitments under the facility by $1 billion to a total of $3.5 billion and to increase the individual borrower sublimit for FE by $1 billion to a total of $3.5 billion. The FES/AE Supply facility was amended to decrease the lending banks' commitments by $1 billion to a total of $1.5 billion. The lending banks' commitments under the FET facility remain at $1 billion and that facility was amended to increase ATSI's individual borrower sublimit to $500 million from $100 million and

TrAIL's individual borrower sublimit to $400 million from $200 million. FirstEnergy expensed approximately $5 million (FES - $3 million) of unamortized debt expense as a result of the amendments. The amount was included in Loss on Debt Redemptions in the Consolidated Statement of Income in the first quarter of 2014.

On March 31, 2014, FE executed, and fully utilized, a new $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances.

During the first quarter of 2014, FG and NG remarketed approximately $417 million of PCRBs previously held by the companies. Of the total, $182 million was remarketed with a fixed interest rate of 4% per annum with a mandatory put date of June 3, 2019 and $235 million was remarketed with a fixed interest rate of 3.75% per annum with a mandatory put date of December 3, 2018.

In addition, in the first quarter of 2014, FG and NG repurchased approximately $197 million and $16 million of PCRBs, respectively, which were subject to a mandatory tender. The companies are currently holding the PCRB's for remarketing subject to future market and other conditions.

On April 1, 2014, PN and ME repurchased approximately $45 million and $29 million of PCRBs, respectively, which were subject to a mandatory put on such date. The companies are currently holding the PCRB's for remarketing subject to future market and other conditions.

8. DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility relating to these exposures, FirstEnergy's Risk Policy Committee, comprised of senior management, provides general management oversight for risk management activities throughout FirstEnergy. The Risk Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy also uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value unless they meet the normal purchases and normal sales criteria. Derivatives that meet those criteria are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance. Changes in the fair value of derivative instruments that qualified and were designated as cash flow hedge instruments are recorded in AOCI. Changes in the fair value of derivative instruments that are not designated as cash flow hedge instruments are recorded in net income on a mark-to-market basis. FirstEnergy has contractual derivative agreements through 2020.

Cash Flow Hedges

FirstEnergy has used cash flow hedges for risk management purposes to manage the volatility related to exposures associated with fluctuating commodity prices and interest rates. The effective portion of gains and losses on a derivative contract is reported as a component of AOCI with subsequent reclassification to earnings in the period during which the hedged forecasted transaction affects earnings.

Total net unamortized gains included in AOCI associated with instruments previously designated to be in a cash flow hedging relationship totaled less than $1 million and $2 million as of March 31, 2014 and December 31, 2013, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Approximately $9 million is expected to be amortized to income during the next twelve months.

FirstEnergy has used forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. No forward starting swap agreements accounted for as a cash flow hedge were outstanding as of March 31, 2014 or December 31, 2013. Total pre-tax unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $57 million and $59 million as of March 31, 2014 and December 31, 2013, respectively. Based on current estimates, approximately $9 million will be amortized to interest expense during the next twelve months.

In connection with certain debt redemptions, FirstEnergy recorded interest expense related to deferred losses on terminated interest rate swaps of approximately $2 million for the three months ended March 31, 2013.

As of March 31, 2014 and December 31, 2013, no commodity or interest rate derivatives were designated as cash flow hedges.

Refer to Note 4, Accumulated Other Comprehensive Income, for reclassifications from AOCI during the three months ended March 31, 2014 and 2013.

Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. These derivative instruments were treated as fair value hedges of fixed-rate, long-term debt issues, protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. As of March 31, 2014 and December 31, 2013, no fixed-for-floating interest rate swap agreements were outstanding.

Unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $41 million and $44 million as of March 31, 2014 and December 31, 2013, respectively. Based on current estimates, approximately $11 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled approximately $3 million and $6 million during the three months ended March 31, 2014 and 2013, respectively.

As of March 31, 2014 and December 31, 2013, no commodity or interest rate derivatives were designated as fair value hedges.

Commodity Derivatives

FirstEnergy uses both physically and financially settled derivatives to manage its exposure to volatility in commodity prices. Commodity derivatives are used for risk management purposes to hedge exposures when it makes economic sense to do so, including circumstances where the hedging relationship does not qualify for hedge accounting.

Electricity forwards are used to balance expected sales with expected generation and purchased power. Natural gas futures are entered into based on expected consumption of natural gas primarily for use in FirstEnergy's combustion turbine units. Heating oil futures are entered into based on expected consumption of oil and the financial risk in FirstEnergy's coal transportation contracts. Derivative instruments are not used in quantities greater than forecasted needs.

As of March 31, 2014, FirstEnergy's net asset position under commodity derivative contracts was $117 million, which related to FES positions. Under these commodity derivative contracts, FES posted $85 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $11 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on commodity derivative contracts held as of March 31, 2014, an adverse change of 10% in commodity prices would decrease net income by approximately $40 million during the next twelve months.

NUGs

As of March 31, 2014, FirstEnergy's net liability position under NUG contracts was $185 million representing contracts held at JCP&L, ME and PN. NUG contracts represent purchased power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. Changes in the fair value of NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

LCAPP

The LCAPP law was enacted in New Jersey during 2011 to promote the construction of qualified electric generation facilities. JCP&L maintained two LCAPP contracts, which were financially settled agreements that allowed eligible generators to receive payments from, or make payments to, JCP&L pursuant to an annually calculated load-ratio share of the capacity produced by the generator based upon the annual forecasted peak demand as determined by PJM. JCP&L expected to recover from its customers payments made to the generators and give credit to customers for payments from the generators under these contracts. As a result, the projected future obligations for the LCAPP contracts were considered derivative liabilities with a corresponding regulatory asset. Since the LCAPP contracts were subject to regulatory accounting, changes in their fair value did not impact earnings. On October 11, 2013, the U.S. District Court for the District of New Jersey declared that the LCAPP was preempted by the FPA and unconstitutional. On October 22, 2013, the Superior Court of New Jersey Appellate Division dismissed two consolidated appeals which had been taken from the final order of the NJBPU which accepted and adopted the recommendation of the NJBPU's Agent regarding implementation of the LCAPP law. Dismissal of the consolidated appeals, along with pending matters currently on remand to the NJBPU, was without prejudice subject to the parties exercising their appellate rights in the federal courts. The parties filed an appeal with the U.S. Court of Appeals for the Third Circuit and briefing by the parties was completed by March 5, 2014. Consistent with the provisions of the LCAPP contracts, the U.S. District Court's ruling was a termination event. During the fourth quarter of 2013, JCP&L issued termination notices to the counterparties and reversed the derivative liability and corresponding regulatory asset on its Consolidated Balance Sheet.

FTRs

As of March 31, 2014, FirstEnergy's and FES's net liability position under FTRs was $1 million and $3 million, respectively, and FES posted $4 million of collateral. FirstEnergy holds FTRs that generally represent an economic hedge of future congestion charges that will be incurred in connection with FirstEnergy's load obligations. FirstEnergy acquires the majority of its FTRs in an annual auction through a self-scheduling process involving the use of ARRs allocated to members of an RTO that have load serving obligations and through the direct allocation of FTRs from the PJM RTO. The PJM RTO has a rule that allows directly allocated FTRs to be granted to LSEs in zones that have newly entered PJM. For the first two planning years, PJM permits the LSEs to request a direct allocation of FTRs in these new zones at no cost as opposed to receiving ARRs. The directly allocated FTRs differ from traditional FTRs in that the ownership of all or part of the FTRs may shift to another LSE if customers choose to shop with the other LSE.

The future obligations for the FTRs acquired at auction are reflected on the Consolidated Balance Sheets and have not been designated as cash flow hedge instruments. FirstEnergy initially records these FTRs at the auction price less the obligation due to the RTO, and subsequently adjusts the carrying value of remaining FTRs to their estimated fair value at the end of each accounting period prior to settlement. Changes in the fair value of FTRs held by FES and AE Supply are included in other operating expenses as unrealized gains or losses. Unrealized gains or losses on FTRs held by FirstEnergy's utilities are recorded as regulatory assets or liabilities. Directly allocated FTRs are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance.

FirstEnergy records the fair value of derivative instruments on a gross basis. The following table summarizes the fair value and classification of derivative instruments on FirstEnergy's Consolidated Balance Sheets:

Derivative Assets			Derivative Liabilities		
	Fair Value			Fair Value	
	March 31, 2014	December 31, 2013		March 31, 2014	December 31, 2013
	(In millions)			*(In millions)*	
Current Assets - Derivatives			**Current Liabilities - Derivatives**		
Commodity Contracts	$ 240	$ 162	Commodity Contracts	$ (154)	$ (102)
FTRs	7	4	FTRs	(5)	(9)
	247	166		(159)	(111)
			Noncurrent Liabilities - Adverse Power Contract Liability		
			NUGs	(188)	(222)
Deferred Charges and Other Assets - Other			**Noncurrent Liabilities - Other**		
Commodity Contracts	64	53	Commodity Contracts	(33)	(11)
NUGs	3	20	FTRs	(3)	(3)
	67	73		(224)	(236)
Derivative Assets	$ 314	$ 239	Derivative Liabilities	$ (383)	$ (347)

FirstEnergy enters into contracts with counterparties that allow for net settlement of derivative assets and derivative liabilities. Certain of these contracts contain margining provisions that require the use of collateral to mitigate credit exposure between FirstEnergy and these counterparties. In situations where collateral is pledged to mitigate exposures related to derivative and non-derivative instruments with the same counterparty, FirstEnergy allocates the collateral based on the percentage of the net fair value of derivative instruments to the total fair value of the combined derivative and non-derivative instruments. The following tables summarize the fair value of derivative instruments on FirstEnergy's Consolidated Balance Sheets and the effect of netting arrangements and collateral on its financial position:

March 31, 2014	Fair Value	Amounts Not Offset in Consolidated Balance Sheet: Derivative Instruments	Amounts Not Offset in Consolidated Balance Sheet: Cash Collateral (Received)/Pledged	Net Fair Value
		(In millions)		
Derivative Assets				
Commodity contracts	$ 304	$ (182)	$ (4)	$ 118
FTRs	7	(7)	—	—
NUG contracts	3	—	—	3
	$ 314	$ (189)	$ (4)	$ 121
Derivative Liabilities				
Commodity contracts	$ (187)	$ 182	$ 2	$ (3)
FTRs	(8)	7	1	—
NUG contracts	(188)	—	—	(188)
	$ (383)	$ 189	$ 3	$ (191)

December 31, 2013	Fair Value	Amounts Not Offset in Consolidated Balance Sheet: Derivative Instruments	Amounts Not Offset in Consolidated Balance Sheet: Cash Collateral (Received)/Pledged	Net Fair Value
		(In millions)		
Derivative Assets				
Commodity contracts	$ 215	$ (106)	$ (9)	$ 100
FTRs	4	(4)	—	—
NUG contracts	20	—	—	20
	$ 239	$ (110)	$ (9)	$ 120
Derivative Liabilities				
Commodity contracts	$ (113)	$ 106	$ 7	$ —
FTRs	(12)	4	5	(3)
NUG contracts	(222)	—	—	(222)
	$ (347)	$ 110	$ 12	$ (225)

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of March 31, 2014:

	Purchases	Sales	Net	Units
		(In millions)		
Power Contracts	41	38	3	MWH
FTRs	26	—	26	MWH
NUGs	7	—	7	MWH
Natural Gas	65	8	57	mmBTU

The effect of derivative instruments not in a hedging relationship on the Consolidated Statements of Income during the three months ended March 31, 2014 and 2013, are summarized in the following tables:

	Three Months Ended March 31		
	Commodity Contracts	FTRs	Total
	(In millions)		
2014			
Unrealized Gain Recognized in:			
Other Operating Expense [1]	$12	$5	$17
Realized Gain (Loss) Reclassified to:			
Revenues [2]	($13)	$52	$39
Purchased Power Expense [3]	436	—	436
Other Operating Expense [4]	—	(7)	(7)
Fuel Expense	9	—	9

[1] Includes $12 million for commodity contracts and $5 million for FTRs associated with FES.

[2] Represents losses on structured financial contracts. Includes ($13) million for commodity contracts and $51 million for FTRs associated with FES.

[3] Realized losses on financially settled wholesale sales contracts of $321 million resulting from higher market prices were netted in purchased power. Includes $436 million for commodity contracts associated with FES.

[4] Includes ($7) million for FTRs associated with FES.

2013			
Unrealized Loss Recognized in:			
Other Operating Expense [5]	($5)	($2)	($7)
Realized Gain (Loss) Reclassified to:			
Revenues [6]	$10	$7	$17
Purchased Power Expense [7]	(11)	—	(11)
Other Operating Expense [8]	—	(9)	(9)
Fuel Expense	(1)	—	(1)

[5] Includes ($5) million for commodity contracts and ($1) million for FTRs associated with FES.

[6] Includes $10 million for commodity contracts and $6 million for FTRs associated with FES.

[7] Includes ($11) million for commodity contracts associated with FES.

[8] Includes ($8) million for FTRs associated with FES.

The unrealized and realized gains (losses) on FirstEnergy's derivative instruments subject to regulatory accounting during the three months ended March 31, 2014 and 2013, are summarized in the following tables:

	Three Months Ended March 31			
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	LCAPP[1]	Regulated FTRs	Total
	(In millions)			
2014				
Unrealized Gain on Derivative Instrument	$ 27	$ —	$ 4	$ 31
Realized Loss on Derivative Instrument	(10)	—	(1)	(11)
2013				
Unrealized Gain (Loss) on Derivative Instrument	$ 18	$ (2)	$ —	$ 16
Realized Gain (Loss) on Derivative Instrument	23	—	(1)	22

[1] During the fourth quarter of 2013, all LCAPP contracts were terminated as discussed above.

The following tables provide a reconciliation of changes in the fair value of certain contracts that are deferred for future recovery from (or credit

to) customers during the three months ended March 31, 2014 and 2013:

Derivatives Not in a Hedging Relationship with Regulatory Offset	Three Months Ended March 31			
	NUGs	LCAPP[1]	Regulated FTRs	Total
	(In millions)			
Outstanding net liability as of January 1, 2014	$ (202)	$ —	$ —	$ (202)
Additions/Change in value of existing contracts	27	—	4	31
Settled contracts	(10)	—	(1)	(11)
Outstanding net liability as of March 31, 2014	$ (185)	$ —	$ 3	$ (182)
Outstanding net liability as of January 1, 2013	$ (254)	$ (144)	$ —	$ (398)
Additions/Change in value of existing contracts	18	(2)	—	16
Settled contracts	23	—	(1)	22
Outstanding net liability as of March 31, 2013	$ (213)	$ (146)	$ (1)	$ (360)

[1] During the fourth quarter of 2013, all LCAPP contracts were terminated as discussed above.

9. REGULATORY MATTERS

STATE REGULATION

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES and AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES, AE Supply and their public utility affiliates. In addition, if any of the FirstEnergy affiliates were to engage in the construction of significant new transmission or generation facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission or generation facility.

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to residential SOS for PE customers expired on December 31, 2012, by statute, service continues in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential SOS have also expired; however, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change. PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. PE's initial plan submitted in compliance with the statute was approved in 2009 and covered 2009-2011, the first three years of the statutory period. Expenditures were originally estimated to be approximately $101 million for the PE programs for the entire period of 2009-2015. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan for the second three year period, 2012-2014, that includes additional and improved programs. The 2012-2014 plan is expected to cost approximately $66 million out of the original $101 million estimate for the entire EmPOWER program. On December 22, 2011, the MDPSC issued an order approving PE's second plan with various modifications and follow-up assignments. PE continues to recover program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date such recovery has not been sought or obtained by PE.

Pursuant to a bill passed by the Maryland legislature in 2011, the MDPSC adopted rules, effective May 28, 2012, that create specific requirements related to a utility's obligation to address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. The MDPSC will be required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. The new rules set utility-specific SAIDI and SAIFI targets for 2012-2015; prescribe detailed tree-trimming requirements, outage restoration and downed wire response deadlines; and impose other reliability and customer satisfaction requirements. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately $106 million over the period 2012-2015. On April 1, 2013, the Maryland electric utilities, including PE, filed their first annual reports on compliance with the new rules. The MDPSC conducted a hearing on August 20, 2013 to discuss the reports, after which an order was issued on September 3, 2013, which accepted PE's filing and the operational changes proposed therein. PE filed its second annual report on March 27, 2014.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards which had become final on May 28, 2012; selective increased investment in system hardening; creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the utilities to submit several reports over a series of months, relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further requires the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE has responded to the requirements in the order consistent with the schedule set forth therein. PE's final filing on September 3, 2013, discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would expect to make approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. The MDPSC has ordered that certain reports of its Staff relating to these matters be provided by July 1, 2014, and otherwise has not issued a schedule for further proceedings in this matter.

NEW JERSEY

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On September 7, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. In its written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012. In the filing, JCP&L requested approval to increase its revenues by approximately $31.5 million and reserved the right to update the filing to include costs associated with the impact of Hurricane Sandy. The NJBPU transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ has been assigned. On February 22, 2013, JCP&L updated its filing to request recovery of $603 million of distribution-related Hurricane Sandy restoration costs, resulting in increasing the total revenues requested to approximately $112 million. On June 14, 2013, JCP&L further updated its filing to: 1) include the impact of a depreciation study which had been directed by the NJBPU; 2) remove costs associated with 2012 major storms, consistent with the NJBPU orders establishing a generic proceeding to review 2011 and 2012 major storm costs (discussed below); and 3) reflect other revisions to JCP&L's filing. That filing represented an increase of approximately $20.6 million over the revenues produced by existing base rates. Testimony has also been filed in the matter by the Division of Rate Counsel and several other intervening parties in opposition to the base rate increase JCP&L requested. Specifically, the testimony of the Division of Rate Counsel's witnesses recommended that revenues produced by JCP&L's base rates for electric service be reduced by approximately $202.8 million (such amount did not address the revenue requirements associated with major storm events of 2011 and 2012, which are subject to review in the generic proceeding). JCP&L filed rebuttal testimony in response to the testimony of other parties on August 7, 2013. Hearings in the rate case have concluded. In the initial briefs of the parties filed on January 27, 2014, the Division of Rate Counsel recommended that base rate revenues be reduced by $214.9 million while the NJBPU Staff recommended a $207.4 million reduction (such amounts do not address the revenue requirements associated with the major storm events of 2011 and 2012). Reply briefs were filed on February 24, 2014. The matter is pending before the ALJ.

On March 20, 2013, the NJBPU ordered that a generic proceeding be established to investigate the prudence of costs incurred by all New Jersey utilities for service restoration efforts associated with the major storm events of 2011 and 2012. The Order provided that if any utility had already filed a proceeding for recovery of such storm costs, to the extent the amount of approved recovery had not yet been determined, the prudence of such costs would be reviewed in the generic proceeding. On May 31, 2013, the NJBPU clarified its earlier order to indicate that the 2011 major storm costs would be reviewed expeditiously in the generic proceeding with the goal of maintaining the base rate case schedule established by the ALJ where recovery of such costs would be addressed. The NJBPU further indicated in the May 31 clarification that it would review the 2012 major storm costs in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding. On June 21, 2013, consistent with NJBPU's orders, JCP&L filed the detailed report in support of recovery of major storm costs with the NJBPU. On February 24, 2014, a Stipulation was filed with the NJBPU by JCP&L, the Division of Rate Counsel and NJBPU Staff which will allow recovery of $736 million of JCP&L's $744 million of costs related to the significant weather events of 2011 and 2012. As a result, FirstEnergy recorded a regulatory

asset impairment charge of approximately $8 million (pre-tax) as of December 31, 2013. By its Order of March 19, 2014, the NJBPU approved the Stipulation of Settlement and on March 25, 2014, transmitted a copy of that Order to the Office of Administrative Law so that "actual recovery of the 2011 costs can be determined in relation to the pending base rate case." Recovery of 2011 storm costs will be addressed in the pending base rate case; recovery of 2012 storm costs will be determined by the NJBPU.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held in September 2011 to solicit comments regarding the state of preparedness and responsiveness of New Jersey's EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 28, 2011 related to this inquiry. On December 14, 2011, the NJBPU Staff filed a report of its preliminary findings and recommendations with respect to the electric utility companies' planning and response to Hurricane Irene and the October 2011 snowstorm. The NJBPU selected a consultant to further review and evaluate the New Jersey EDCs' preparation and restoration efforts with respect to Hurricane Irene and the October 2011 snowstorm, and the consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. JCP&L submitted written comments on the report. On January 24, 2013, based upon recommendations in its consultant's report, the NJBPU ordered the New Jersey EDCs to take a number of specific actions to improve their preparedness and responses to major storms. The order includes specific deadlines for implementation of measures with respect to preparedness efforts, communications, restoration and response, post event and underlying infrastructure issues. On May 31, 2013, the NJBPU ordered that the New Jersey EDCs implement a series of new communications enhancements intended to develop more effective communications among EDCs, municipal officials, customers and the NJBPU during extreme weather events and other expected periods of extended service interruptions. The new requirements include making information regarding estimated times of restoration available on the EDC's web sites and through other technological expedients. JCP&L is implementing the required measures consistent with the schedule set out in the above NJBPU's orders.

OHIO

The Ohio Companies primarily operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include:

- Generation supplied through a CBP;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, which also applies to tranches assigned post-auction;
- A 6% generation discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- No increase in base distribution rates through May 31, 2014; and
- A new distribution rider, Rider DCR, to recover a return of, and on, capital investments in the delivery system.

The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI's integration into PJM for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain PJM proceedings. The Ohio Companies also agreed to establish a $12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012. Several parties timely filed applications for rehearing. The PUCO issued an Entry on Rehearing on January 30, 2013 denying all applications for rehearing. Notices of appeal to the Supreme Court of Ohio were filed by two parties in the case, Northeast Ohio Public Energy Council and the ELPC. While briefing has been completed, the matter has not yet been scheduled for oral argument.

As approved, the ESP 3 plan continues certain provisions from the current ESP including:

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the existing ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan provides additional provisions, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Under SB221, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. The Ohio Companies were also required to reduce peak

demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018. On May 15, 2013, the Ohio Companies filed their 2012 Status Update Report in which they indicated compliance with 2012 statutory energy efficiency and peak demand reduction benchmarks.

In accordance with PUCO Rules and a PUCO directive, on July 31, 2012 the Ohio Companies filed their three-year portfolio plan for the period January 1, 2013 through December 31, 2015. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period, which is expected to be recovered in rates to the extent approved by the PUCO. Hearings were held with the PUCO in October 2012. On March 20, 2013, the PUCO approved the three-year portfolio plan for 2013-2015. Applications for rehearing were filed by the Ohio Companies and several other parties on April 19, 2013. The Ohio Companies filed their request for rehearing primarily to challenge the PUCO's decision to mandate that they offer planned energy efficiency resources into PJM's base residual auction. On May 15, 2013, the PUCO granted the applications for rehearing for the sole purpose of further consideration of the matter. On July 17, 2013, the PUCO denied the Ohio Companies' application for rehearing, in part, but authorized the Ohio Companies to receive 20% of any revenues obtained from bidding energy efficiency and demand response reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. On August 16, 2013, ELPC and OCC filed applications for rehearing under the basis that the PUCO's authorization for the Ohio Companies to share in the PJM revenues was unlawful. The PUCO granted rehearing on September 11, 2013 for the sole purpose of further consideration of the issue.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with and are not supported by statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal. The Ohio Companies' response was filed on November 4, 2013. The motion is still pending and additional briefing has followed. While briefing has been completed, the matter has not been scheduled for oral argument.

SB221 requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2024. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet the renewable energy requirements established under SB221. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs and selected auditors to perform a financial and management audit. Final audit reports filed with the PUCO generally supported the Ohio Companies' approach to procurement of RECs, but also recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of in-state renewable obligations that the auditor characterized as excessive. Following the hearing, the PUCO issued an Opinion and Order on August 7, 2013 approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for part of the purchases arising from one auction and directing the Ohio Companies to credit non-shopping customers in the amount of $43.3 million, plus interest, and to file tariff schedules reflecting the refund and interest costs within 60 days following the issuance of a final appealable order on the basis that the Ohio Companies did not prove such purchases were prudent. The Ohio Companies, along with other parties, timely filed applications for rehearing on September 6, 2013. On December 18, 2013, the PUCO denied all of the applications for rehearing. Based on the PUCO ruling a regulatory charge of approximately $51 million, including interest, was recorded in the fourth quarter of 2013. On December 24, 2013, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio. On February 10, 2014, the Supreme Court of Ohio granted the Ohio Companies' motion for stay, which went into effect on February 14, 2014. On February 18, 2014, the Office of Consumers' Counsel and the ELPC also filed appeals of the PUCO's order. The Ohio Companies filed their merit brief with the Supreme Court of Ohio on March 6, 2014. On April 15, 2014, the Supreme Court of Ohio stayed the briefing schedule pending the court's resolution of the Ohio Companies' motion to seal certain confidential portions of the appendix and supplement to their merit brief.

The Ohio Companies conducted an RFP in 2013 to cover their all-state SREC and their in-state and all-state REC compliance obligations. On April 15, 2014, the Ohio Companies reported that they met all of their annual renewable energy resource requirements for reporting year 2013.

The PUCO instituted a statewide investigation on December 12, 2012 to evaluate the vitality of the competitive retail electric service market in Ohio. The PUCO provided interested stakeholders the opportunity to comment on twenty-two questions. The questions posed are categorized as market design and corporate separation. The Ohio Companies timely filed their comments on March 1, 2013, and filed reply comments on April 5, 2013. On June 5, 2013, the PUCO requested additional comments and reply comments on the topics of market design and corporate separation, which the Ohio Companies timely filed on July 8, 2013 and July 22, 2013, respectively. The PUCO held a series of workshops throughout 2013, which included an en banc workshop on December 11, 2013. The PUCO Staff filed a report on January 16, 2014, which contained a limited discussion of the workshops and the PUCO Staff's recommendations. The Ohio Companies submitted comments on February 6, 2014 and Reply Comments on February 20, 2014. The PUCO issued its Order in this matter on March 26, 2014, which included a wide range of issues such as, maintaining SSO service in its current form, requiring corporate separation audits of all EDUs, establishing a market development working group, and ordering changes to the bill format. The Ohio Companies filed their Application for Rehearing on April 25, 2014. The Ohio Companies filed their memorandum contra applications for rehearing of other stakeholders on May 5, 2014.

On April 9, 2014, the PUCO initiated a generic investigation of marketing practices in the competitive retail electric service market, with a focus on the marketing of fixed-price or guaranteed percent-off SSO rate contracts where there is a provision that permits the pass-through of new or additional charges.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2015, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through descending clock auctions, competitive requests for proposals and spot market purchases. On November 4, 2013, the Pennsylvania Companies filed a DSP that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2015 through May 31, 2017. The Pennsylvania Companies proposed programs call for quarterly descending clock auctions to procure 3, 12, 24, and 48-month energy contracts, as well as, one RFP seeking 2-year contracts to secure SRECs for ME, PN, and Penn. The Pennsylvania Companies have reached a settlement with all parties on all issues raised in the case with the exception of the treatment of NITS charges. On May 6, 2014, the ALJ issued a Recommended Decision recommending adoption of the settlement without modification and the denial of several parties' request for non-bypassable treatment of NITS charges. A final order is expected from the PPUC by August 2014.

The PPUC entered an Order on March 3, 2010 that denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed ME and PN to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC. Pursuant to a plan approved by the PPUC, ME and PN refunded those amounts to customers over a 29-month period that began in January of 2011. On appeal, the Commonwealth Court affirmed the PPUC's Order to the extent that it holds that line loss costs are not transmission costs and, therefore, the approximately $254 million in marginal transmission losses and associated carrying charges for the period prior to January 1, 2011, are not recoverable under ME's and PN's TSC riders. The Pennsylvania Supreme Court denied ME's and PN's Petition for Allowance of Appeal and the Supreme Court of the United States denied ME's and PN's Petition for Writ of Certiorari. ME and PN also filed a complaint in the U.S. District Court for the Eastern District of Pennsylvania to obtain an order that would enjoin enforcement of the PPUC and Pennsylvania court orders under a theory of federal preemption on the question of retail rate recovery of the marginal transmission loss charges. On September 30, 2013, the U.S. District Court granted the PPUC's motion to dismiss. As a result of the U.S. District Court's decision, FirstEnergy recorded a regulatory asset impairment charge of approximately $254 million (pre-tax) in the quarter ended September 30, 2013. The balance of marginal transmission losses was fully refunded to customers by the second quarter of 2013. On October 29, 2013, ME and PN filed a Notice of Appeal of the U.S. District Court's decision to dismiss the complaint with the United States Court of Appeals for the Third Circuit. Oral argument was held on April 8, 2014, and, at the end of the argument, the Third Circuit directed ME and PN, and the PPUC, each to submit a brief on April 16, 2014 on the question of whether it is possible to waive the preemptive effect of FERC's classification of line loss charges as transmission charges. On April 16, 2014, ME and PN, the PPUC, and the Pennsylvania Industrials each submitted briefs on the Third Circuit's questions.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan (EE&C Plan) by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 provides for potentially significant financial penalties to be assessed on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted a report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. ME, PN and Penn achieved the 2011 benchmarks; however WP did not. WP could be subject to a statutory penalty of between $1 and $20 million. On November 15, 2013, the Pennsylvania Companies submitted their energy efficiency and peak demand reduction report for the period ending May 31, 2013, in which they indicated that all of the Pennsylvania Companies met their statutory requirements. On March 20, 2014, the PPUC issued an Order initially determining that ME, PN and Penn achieved the 2011 and 2013 statutory energy efficiency benchmarks. The PPUC also initially determined that WP is not in compliance with the 2011 statutory energy efficiency benchmarks but is in compliance with the 2013 energy efficiency benchmarks. As such, the PPUC, with regards to WP's compliance with the 2011 statutory benchmarks, referred the matter to the PPUC Bureau of Investigation and Enforcement for the initiation of an appropriate proceeding no later than May 30, 2014 to investigate whether WP is in compliance with the 2011 statutory benchmarks and whether WP is subject to statutory penalties. The PPUC also ordered that the initial determination will be deemed final unless any petitions challenging its initial determination are filed within 20 days of the Order. On April 9, 2014, WP filed its petition challenging the PPUC's initial determination arguing, among other things, that the May 2011 target was not mandatory and WP is in compliance because it achieved its May 2013 targets. On April 21, 2014, WP filed an appeal with the Commonwealth Court of Pennsylvania in which it challenged the PPUC's initial finding of a violation of Act 129 on due process grounds. On that same day, the Bureau of Investigation and Enforcement, consistent with the PPUC's March 20, 2014 Order, initiated a proceeding by filing a Complaint against WP in which it alleges that WP violated Act 129 and recommends a penalty in the amount of $11.4 million. The Pennsylvania Companies have 20 days in which to respond to the Complaint. A prehearing conference is scheduled for May 9, 2014 at which time a procedural schedule for this matter is expected to be established.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 15, 2012, a Phase II EE&C Plan that would be in

effect for the period June 1, 2013 through May 31, 2016. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator. Based upon information received, the PPUC has not included a peak demand reduction requirement in the Phase II plans. The Pennsylvania Companies filed their Phase II plans and supporting testimony in November 2012. On January 16, 2013, the Pennsylvania Companies reached a settlement with all but one party on all but one issue. The settlement provides for the Pennsylvania Companies to meet with interested parties to discuss ways to expand upon the EE&C programs and incorporate any such enhancements after the plans are approved, provided that these enhancements will not jeopardize the Pennsylvania Companies' compliance with their required targets or exceed the statutory spending caps. On February 6, 2013, the Pennsylvania Companies filed revised Phase II EE&C Plans to conform the plans to the terms of the settlement. Total costs of these plans are expected to be approximately $234 million. All such costs are expected to be recoverable through the Pennsylvania Companies reconcilable Phase II EE&C Plan C riders. The remaining issue, raised by a natural gas company, involved the recommendation that the Pennsylvania Companies include in their plans incentives for natural gas space and water heating appliances. On March 14, 2013, the PPUC approved the 2013-2016 EE&C plans of the Pennsylvania Companies, adopting the settlement, and rejecting the natural gas companies recommendations.

In addition, Act 129 required utilities to file a SMIP with the PPUC. On December 31, 2012, the Pennsylvania Companies filed their Smart Meter Deployment Plan. The Deployment Plan requested deployment of approximately 98.5% of the smart meters to be installed over the period 2013 to 2019, and the remaining meters in difficult to reach locations to be installed by 2022, with an estimated life cycle cost of about $1.25 billion. Such costs are expected to be recovered through the Pennsylvania Companies' PPUC-approved Riders SMT-C. Evidentiary hearings were held and briefs were submitted by the Pennsylvania Companies and the OCA. On November 8, 2013, the ALJ issued a Recommended Decision recommending that the Pennsylvania Companies' Deployment Plan be adopted with certain modifications, including, among other things, that the Pennsylvania Companies perform further benchmarking analyses on their costs and hire an independent consultant to perform further analyses on potential savings. On December 2, 2013, the Pennsylvania Companies submitted exceptions in which they challenged, among other things, certain recommendations in the ALJ's decision, and requested approval of a modification to the deployment schedule so as to allow the entire Penn smart meter system (170,000 meters) to be built by the end of 2015, instead of the original proposed installation of 60,000 meters by the end of 2016. The OCA took exception to one issue and both parties filed replies to exceptions on December 12, 2013. In its March 6, 2014 Opinion and Order, the PPUC rejected the OCA's exception and many of the ALJ's recommendations, including the recommendation to hire an independent consultant and the disallowance of $5.1 million of customer information system costs, and affirmed the ALJ's recommendation on the accounting treatment for legacy meter costs. The PPUC also directed the Pennsylvania Companies to file an amendment to the Deployment Plan within thirty days of the Order with sufficient supporting documentation for proper evaluation if the Pennsylvania Companies intend to pursue an accelerated deployment schedule, and the PPUC indicated that it would establish an expedited procedural schedule and rule on the filing within 90 days of the March 6, 2014 Order. The Pennsylvania Companies filed an amended Deployment Plan on March 19, 2014, to which, the OCA filed exceptions arguing that the amended plan failed to: 1) list certain potential cost savings categories that are to be considered by the Pennsylvania Companies; and 2) follow proper procedure. On April 7, 2014, the Pennsylvania Companies filed a reply to OCA’s exceptions explaining why they should be rejected. A prehearing conference was held on April 25, 2014, and a procedural schedule was established that is expected to allow the PPUC to issue an order by June 5, 2014.

In the PPUC Order approving the FirstEnergy and AE merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions concerning retail markets in Pennsylvania to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A final order was issued on February 15, 2013, providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items. Subsequently, the PPUC established five workgroups and one comment proceeding in order to seek resolution of certain matters and to clarify certain obligations that arose from that order.

The PPUC issued a Proposed Rulemaking Order on August 25, 2011, which proposed a number of substantial modifications to the current Code of Conduct regulations that were promulgated to provide competitive safeguards to the competitive retail electricity market in Pennsylvania. The proposed changes include, but are not limited to: an EGS may not have the same or substantially similar name as the EDC or its corporate parent; EDCs and EGSs would not be permitted to share office space and would need to occupy different buildings; EDCs and affiliated EGSs could not share employees or services, except certain corporate support, emergency, or tariff services (the definition of "corporate support services" excludes items such as information systems, electronic data interchange, strategic management and planning, regulatory services, legal services, or commodities that have been included in regulated rates at less than market value); and an EGS must enter into a trademark agreement with the EDC before using its trademark or service mark. The Proposed Rulemaking Order was published on February 11, 2012, and comments were filed by the Pennsylvania Companies and FES on March 27, 2012. If implemented these rules could require a significant change in the ways FES and the Pennsylvania Companies do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition. Pennsylvania's Independent Regulatory Review Commission subsequently issued comments on the proposed rulemaking on April 26, 2012, which called for the PPUC to further justify the need for the proposed revisions by citing a lack of evidence demonstrating a need for them. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified. On March 24, 2014, the PPUC issued a letter withdrawing the Proposed Rulemaking.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement reached with the other parties and approved by the WVPSC in June 2010 that provided for:

- $40 million annualized base rate increases effective June 29, 2010;
- Deferral of February 2010 storm restoration expenses over a maximum five-year period;
- Additional $20 million annualized base rate increase effective in January 2011;
- Decrease of $20 million in ENEC rates effective January 2011, providing for deferral of related costs for later recovery in 2012; and
- Moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012 and two public input hearings have been held. The WVPSC issued an Order in this matter on January 23, 2013 closing the proceeding and directing electric utilities to file a vegetation management plan within six months and to propose a cost recovery mechanism. This Order also requires MP and PE to file a status report regarding improvements to their storm response procedures by the same date. On July 23, 2013, MP and PE filed their vegetation management plans, which provided for recovery of costs through a surcharge mechanism. A hearing was held on December 3, 2013, and briefing followed. The WVPSC issued an order on April 14, 2014 approving the plan, stating rate recovery will be addressed in the base rate case filed on April 30, 2014. In the interim, MP and PE are authorized to defer all costs associated with the plan.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE filed a Petition for approval of a Generation Resource Transaction with the WVPSC in November 2012 that proposed a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer involved MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. FERC authorized the transfers on April 23, 2013 and the financing on May 13, 2013. A Joint Settlement Agreement was filed by the majority of parties on August 21, 2013. On October 7, 2013, the WVPSC authorized the transaction, with certain conditions, and on October 9, 2013, the transaction closed resulting in MP recording a pre-tax impairment charge of approximately $322 million in the fourth quarter of 2013 to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. Concurrently, MP recognized a regulatory liability of approximately $23 million representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. The $1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately $527 million and a note payable to AE Supply of approximately $573 million. The note payable to AE Supply was paid in the fourth quarter of 2013. The settlement also required MP and PE to file a base rate case by April 30, 2014. On November 6, 2013, the WVCAG petitioned for appeal with the Supreme Court of Appeals of West Virginia. MP and PE filed their response to the WVCAG petition on December 27, 2013 and WVCAG filed its reply on January 16, 2014. The Supreme Court of Appeals of West Virginia held oral arguments on March 5, 2014. On April 23, 2014 the Supreme Court of Appeals of West Virginia delivered an Opinion affirming the WVPSC order approving the Generation Resource Transaction.

On April 30, 2014, MP and PE filed a rate case requesting a base rate increase of approximately $96 million, or 9.3%. The filing also included a surcharge to recover costs of MP's and PE's vegetation management program in the amount of approximately $48 million. The proposed total rate increase request, including the cost of the vegetation management program, is approximately $144 million, or 14%. MP and PE anticipate a decision from the WVPSC in February 2015.

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, ATSI and TrAIL. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases “self-reporting” an item to RFC. Moreover, it is clear that the NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards

for its bulk power system could result in the imposition of financial penalties that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis - each customer in the zone would pay based on its total usage of energy within PJM. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit found that FERC had not supported a prior FERC decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on that finding, remanded the rate design issue to FERC. In an order dated January 21, 2010, FERC set this matter for a “paper hearing” and requested parties to submit written comments. FERC identified nine separate issues for comment and directed PJM to file the first round of comments. PJM filed certain studies with FERC on April 13, 2010, which demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain LSEs in PJM bearing the majority of the costs. FirstEnergy and a number of other utilities, industrial customers and state utility commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state utility commissions supported continued socialization of these costs on a load ratio share basis. On March 30, 2012, FERC issued an order on remand reaffirming its prior decision that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp (or socialized) rate based on the amount of load served in a transmission zone and concluding that such methodology is just and reasonable and not unduly discriminatory or preferential. On April 30, 2012, FirstEnergy requested rehearing of FERC's March 30, 2012 order and on March 22, 2013, FERC denied rehearing. On March 29, 2013, FirstEnergy filed a Petition for Review with the U.S. Court of Appeals for the Seventh Circuit, and the case subsequently was consolidated with several other cases before that court for briefing and disposition. Briefing is complete, oral argument was held on April 22, 2014, and a decision is expected in 2014.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the effective date of the compliance filing. On January 31, 2013, FERC conditionally accepted the hybrid method to be effective on February 1, 2013, subject to refund and to a future order on PJM's separate Order No. 1000 compliance filing. On March 22, 2013, FERC again accepted the hybrid method. Certain parties sought rehearing of parts of FERC's March 22, 2013 order. These requests for rehearing are pending before FERC. On July 10, 2013, the PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between: (1) the PJM region and the NYISO region and; (2) the PJM region and the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the cost of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region. On the same date, also in response to Order No. 1000, the PJM transmission owners, including FirstEnergy, also submitted to FERC a filing stating that the cost allocation provisions for interregional transmission projects provided in the Joint Operating Agreement between PJM and MISO comply with the requirements of Order No. 1000. On December 30, 2013, FERC conditionally accepted the PJM/SERTP cross-border project cost allocation filing, subject to refund and future orders in PJM's and SERTP's related Order No. 1000 interregional compliance proceedings. The PJM/NYISO and PJM/MISO cross-border project cost allocation filings remain pending before FERC. On January 16, 2014, FERC issued an order regarding the effective date of PJM's separate Order No. 1000 regional transmission planning and cost allocation compliance filing, noting that it would address the merits of the comments on and protests to that filing and related compliance filings in a future order.

Numerous parties, including ATSI, FES, TrAIL, OE, CEI, TE, Penn, JCP&L, ME, MP, PN, WP and PE, sought judicial review of Order No. 1000 before the U.S. Court of Appeals for the D.C. Circuit. Briefing is complete and oral argument was held on March 20, 2014.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone. While many of the matters involved with the move have been resolved, FERC denied recovery by means of ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis that demonstrates net benefits to customers from the move. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC to resolve the exit fee and transmission cost allocation issues. However, FERC subsequently rejected that settlement, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. On October 21, 2013, FirstEnergy filed a request for rehearing of FERC's order.

Separately, the question of ATSI's responsibility for certain costs for the “Michigan Thumb” transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings in front of FERC and certain U.S. appellate courts. The MISO and its allied parties assert that the benefits to the ATSI zone of the Michigan Thumb project are roughly commensurate with the costs that MISO desires to charge to the ATSI zone, estimated to be as much as $16 million per year. ATSI has submitted evidence that the Michigan Thumb project provides no electric benefits to the ATSI zone and, on that basis, opposes the MISO’s efforts to impose these costs on the ATSI zone loads. The MISO and its allied parties also assert that certain language in the MISO Transmission Owners Agreement requires ATSI to pay these charges. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. While FERC proceedings regarding whether the MISO can charge ATSI for MVP costs remain pending, on February 24, 2014, the U.S. Supreme Court declined to hear appeals filed by FirstEnergy and other parties of the Seventh Circuit's June 2013 decision upholding FERC's acceptance of the MISO's generic MVP cost allocation proposal.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to transmission customers in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. ATSI subsequently filed a petition for review with the U.S. Court of Appeals for the D.C. Circuit. Briefing is complete, oral argument was held on December 11, 2013, and a decision is expected in the second quarter of 2014.

The outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM cannot be predicted at this time.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the U.S. Court of Appeals for the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets, during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011, and affirmed the dismissal in June 2012. On June 20, 2012, the California Parties appealed FERC's decision back to the Ninth Circuit. Briefing was completed before the Ninth Circuit on October 23, 2013. The timing of further action by the Ninth Circuit is unknown.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed another complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General has appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

The PATH project was proposed to be comprised of a 765 kV transmission line from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland. PJM initially authorized construction of the PATH project in June 2007. On August 24, 2012, the PJM Board of Managers canceled the PATH project, which it had suspended in February 2011. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed return on equity of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% return on equity adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement judge procedures and hearing if the parties do not agree to a settlement. PATH, PATH-Allegheny and PATH-WV have requested rehearing of FERC's denial of the 0.5% return on equity adder for RTO membership; that request for rehearing remains pending before FERC. In addition, FERC consolidated for settlement judge procedures and hearing purposes three formal challenges to the PATH formula rate annual updates submitted to FERC in June 2010, June 2011 and June 2012, with the September 28, 2012 filing for recovery of costs associated with the cancellation of the PATH project.

On March 20, 2014, the settlement judge declared an impasse in efforts to achieve settlement. On March 24, 2014, the Chief ALJ terminated settlement judge procedures and appointed an ALJ to preside over the hearing phase of the case. The hearing is scheduled to commence on November 5, 2014. The issues set for hearing include the prudence of the costs, the base return on

equity and the period of recovery. Depending on the outcome of the hearing, PATH-Allegheny and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

Hydroelectric Asset Sale

On September 4, 2013, certain of FirstEnergy's subsidiaries submitted filings with FERC for authorization to sell eleven hydroelectric power plant projects to subsidiaries of Harbor Hydro Holdings, LLC (Harbor Hydro), a subsidiary of LS Power Equity Partners II, LP (LS Power). The eleven hydroelectric projects are: the Seneca Pumped Storage Project, Allegheny Lock & Dam No. 5, Allegheny Lock & Dam No. 6, the Lake Lynn Project, the Millville Hydro Project, the Dam No. 4 Project, the Dam No. 5 Project, and four additional projects located in Shenandoah, Front Royal and Luray, Virginia. The eleven projects have a combined generating capacity of approximately 527 MW. On February 12, 2014, the sale of the hydroelectric power plants to LS Power closed for approximately $394 million. See Note 13, Discontinued Operations for additional information regarding the assets sold.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties have submitted filings arguing that MISO's concerns largely are without foundation and suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. On April 2, 2013, FERC issued an order directing MISO and PJM to make presentations to FERC regarding ongoing regional efforts to address whether barriers to transfer capability exist between the MISO and PJM regions and the actions the FERC should take to address any such barriers. The RTOs presented their respective positions to FERC on June 20, 2013 and provided additional information regarding their stakeholder prioritization survey, in response to a FERC request on June 27, 2013. On September 26, 2013, the RTOs jointly submitted an informational filing providing a description of and schedule for their Joint and Common Market initiatives. On December 19, 2013, FERC issued an order directing that FERC staff are to attend the "joint and common market" stakeholder meetings for the purpose of monitoring progress on the initiatives described in the September 26, 2013 joint informational filing and establishing a new proceeding to reflect the broadened scope of issues contemplated by that filing and the RTOs' joint and common market initiatives. FERC has not acted on the presentations, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

MOPR Reform

On December 7, 2012, PJM filed amendments to its tariff to revise the MOPR used in the RPM. PJM revised the MOPR to add two broad, categorical exemptions, eliminate an existing exemption, and to limit the applicability of the MOPR to certain capacity resources. The filing also included related and conforming changes to the RPM posting requirements and to those provisions describing the role of the Independent Market Monitor for the PJM Region. On May 2, 2013, FERC issued an order in large part accepting PJM's proposed reform of the MOPR, including the proposed exemptions and applicability but also requiring PJM to commit to future review and, if necessary, additional revisions to the MOPR to accommodate changing market conditions. On June 3, 2013, FirstEnergy submitted a request for rehearing of FERC's May 2, 2013 order. In its rehearing request, FirstEnergy referenced the results of the May 2013 PJM RPM capacity auction, and publicly-available data about the reasons for the unexpectedly low "rest-of-RTO" clearing price of $59 per MW-day, as supporting its contention that the MOPR reform depressed prices as predicted in FirstEnergy's December 28, 2012 and January 25, 2013 comments. FirstEnergy's request for rehearing is pending before FERC.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and they operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM tariff, the funds that are set aside to pay FTRs can be diverted to other uses, resulting in "underfunding" of FTR payments. Since June 2010, FES and AE Supply have lost more than $87 million in revenues that they otherwise would have received as FTR holders to hedge congestion costs. FES and AE Supply expect to continue to experience significant underfunding.

On December 28, 2011, FES and AE Supply filed a complaint with FERC for the purpose of modifying certain provisions in the PJM tariff to eliminate FTR underfunding. On March 2, 2012, FERC issued an order dismissing the complaint. In its order, FERC ruled that it was not appropriate to initiate action at that time because of the unknown root causes of FTR underfunding. FERC directed PJM to convene stakeholder proceedings for the purpose of determining the root causes of the FTR underfunding. FERC went on to note that its dismissal of the complaint was without prejudice to FES and AE Supply or any other affected entity filing a complaint if the stakeholder proceedings proved unavailing. FES and AE Supply sought rehearing of FERC's order and, on July 19, 2012, FERC denied rehearing. In April 2012, PJM issued a report on FTR underfunding. However, the PJM stakeholder process proved unavailing as the stakeholders were not willing to change the tariff to eliminate FTR underfunding. Accordingly, on February 15, 2013, FES and AE Supply re-filed their complaint with FERC for the purpose of changing the PJM tariff to eliminate FTR underfunding. Various parties filed responsive pleadings, including PJM. On June 5, 2013, FERC issued its order denying the new complaint. On

July 5, 2013,FESC, on behalf of FES and AE Supply, filed a request for rehearing of FERC's order. That request for rehearing, and all subsequent filings in the docket, are pending before FERC.

PJM RPM Tariff Amendments

In November 2013, PJM began to submit a series of amendments to its RPM capacity tariff in order to address certain problems that have been observed in recent auctions. These problems can be grouped into four categories: (i) Demand Response (DR); (ii) imports; (iii) modeling of transmission upgrades in calculating geographic clearing prices; and (iv) arbitrage/capacity replacement. The purpose of PJM's tariff amendments is to ensure that resources that clear in the RPM auctions are available as physical resources in the delivery year and that the rules implement comparable obligations for different types of resources. In each of the relevant dockets, FirstEnergy submitted comments as part of a coalition of utilities (generally including an affiliate of AEP, Duke and Dayton). The FirstEnergy/coalition position was that all of the PJM proposals should be accepted as proposed, and that the FERC should order PJM to take additional steps that should have the effect of eliminating additional distortions and flaws in the RPM market. PJM made two filings regarding DR; FERC accepted one as proposed on January 30, 2014, and issued a deficiency letter regarding the other on March 6, 2014. FERC also issued deficiency letters requesting additional information from PJM regarding the modeling filing on January 17, 2014 and regarding the imports filing on January 28, 2014. On February 18 and 21, 2014, respectively, PJM filed its responses to FERC's deficiency letters regarding the modeling filing and the imports filing. On April 18, 2014, FERC conditionally accepted PJM's modeling filing, as supplemented, subject to PJM's submission of a compliance filing. On April 22, 2014, FERC accepted PJM's imports filing, as supplemented. The second DR filing, which relates to the rules applicable to DR performance obligations, the arbitrage/capacity replacement filing and related filings in those dockets, and a request for rehearing of the January 30, 2014 order on the first DR filing, are pending before FERC. PJM requested FERC action on the DR performance obligations filing by April 11, 2014, and prior to the May 2014 BRA for the arbitrage/capacity replacement filing. Although FirstEnergy believes that these filings (and the associated tariff changes) should have positive implications for RPM clearing prices, generally there can be no assurance as to their ultimate impact on FirstEnergy.

PJM RPM Auctions - Calculation of Unit-Specific Offer Caps

The PJM RPM capacity tariff describes the rules for calculating the “offer cap” for each unit that offers into the RPM auctions. In summary, the offer cap is calculated by identifying certain going-forward costs, including the going-forward capital requirements, for a given unit, and then subtracting the projected energy and ancillary services revenues, net of marginal costs, from the going-forward costs. The remainder becomes the offer cap. FES learned that the PJM Market Monitor’s practice for calculating the forecast energy and ancillary services revenues has been to use the lower of the unit’s economic or cost-based offers into the PJM energy market. The Market Monitor engages in this practice based on his interpretation of certain provisions of the PJM capacity tariff. However, review of the relevant tariff language suggests that only the cost-based offer data should be used. FES determined that the Market Monitor’s use of the lower of cost-based or economic offer data has the effect of suppressing the offer cap, which can distort the price signal that is intended to come out of the RPM auction process. On April 7, 2014, FES submitted a Petition for Declaratory Order to FERC, asking for an interpretation of the relevant provisions of the PJM capacity tariff. Specifically, FES identified the difference of opinion between FES and the Market Monitor regarding interpretation of the relevant provision and asked FERC to rule on the question of whether the tariff language permits the Market Monitor’s use of the lower of cost-based or economic offer data or requires use of the cost-based offer data. FES asked FERC to rule on the petition by May 9, 2014. On April 18, 2014, the Market Monitor and other parties filed protests to FES's petition, arguing that the PJM capacity tariff allows the Market Monitor to use market-based energy offers instead of cost-based energy offers in calculating RPM auction offer caps and asking FERC to delay action on the petition until after the May 2014 BRA. FES' petition, the protest, and related filings are pending before FERC. The timing of FERC action and the outcome of this proceeding cannot be predicted at this time.

Market-Based Rate Authority, Triennial Update

OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP, PE, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC’s requirements for holding market-based rate authority. On December 20, 2013, FESC submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. That filing is pending before FERC.

10. COMMITMENTS, GUARANTEES AND CONTINGENCIES

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party.

As of March 31, 2014, outstanding guarantees and other assurances aggregated approximately $4.0 billion, consisting of parental guarantees ($896 million), subsidiaries' guarantees ($2,207 million) and other guarantees ($891 million).

FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG, and NG would have claims against each of FES, FG and NG, regardless of whether their primary obligor is FES, FG or NG.

COLLATERAL AND CONTINGENT-RELATED FEATURES

In the normal course of business, FE and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuel, and emission allowances. Certain bilateral agreements and derivative instruments contain provisions that require FE or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FE's or its subsidiaries' credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. The incremental collateral requirement allows for the offsetting of assets and liabilities with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. This posted collateral is used to settle gains or losses on those bilateral agreements or derivatives.

Based on FES' power portfolio exposure as of March 31, 2014, FES has posted collateral of $544 million and AE Supply has posted collateral of $8 million. The Regulated Distribution segment has posted collateral of $28 million. The collateral posted at FES primarily relates to the extreme weather and market conditions experienced in January of 2014. On April 16, 2014, approximately $275 million of cash collateral was returned to FES as a result of the PJM semi-annual peak market activity calculation reset.

These credit-risk-related contingent features stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations as of March 31, 2014:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 461	$ 6	$ 49	$ 516
BB+/Ba1 Credit Ratings	$ 497	$ 6	$ 49	$ 552
Full impact of credit contingent contractual obligations	$ 796	$ 58	$ 87	$ 941

Excluded from the preceding chart is the potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Services Segment. As of March 31, 2014, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES and AE Supply would be required to post $111 million and $1 million, respectively.

OTHER COMMITMENTS AND CONTINGENCIES

FE is a guarantor under a syndicated three-year senior secured term loan facility dated October 18, 2011, as amended, that matures October 18, 2015, under which Global Holding borrowed $350 million. Proceeds from the loan were used to repay Signal Peak's and Global Rail's maturing $350 million syndicated two-year senior secured term loan facility. In addition to FE, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, have also provided their joint and several guarantees of the obligations of Global Holding under the new facility.

In connection with the facility, 69.99% of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with FEV's and WMB Marketing Ventures, LLC's respective 33-1/3% membership interests in Global Holding, are pledged to the lenders as collateral.

FE, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed, most recently as of August 14, 2013, to use their best efforts to refinance the facility no later than July 20, 2015, on a non-recourse basis so that FE's guaranty can be terminated and/or released. If that refinancing does not occur, FE may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the facility in full. In lieu of providing such funding, the co-owners, at FE's option, may provide their several guaranties of Global Holding's obligations under the facility. Since January 1, 2013, FE has received a fee for providing its guaranty. The fee is payable semiannually, and accrues at a rate of 5% per annum on the average daily outstanding aggregate commitments under the facility for each semiannual period.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

CAA Compliance

FirstEnergy is required to meet federally-approved SO_2 and NOx emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner.” One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued an NOV to GenOn Energy, Inc. alleging NSR violations at the Keystone, Portland and Shawville coal-fired plants based on “modifications” dating back to the mid-1980s. JCP&L, as the former owner of 16.67% of the Keystone Station, ME, as a former owner and operator of the Portland Station, and PN as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations, at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. The EPA's NOV alleges equipment replacements during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically, opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. FG intends to comply with the CAA and Ohio regulations, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued additional CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply, MP, PE and WP in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that AE performed major modifications in violation of the NSR provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. A non-jury trial on liability only was held in September 2010. On February 6, 2014, the Court entered judgment for AE, AE Supply, MP, PE and WP finding they had not violated the CAA or the Pennsylvania Air Pollution Control Act. On March 10, 2014, New York, Connecticut, and Maryland filed an appeal with the U.S. Court of Appeals for the Third Circuit. This decision does not change the status of these plants which remain deactivated.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the D.C. Circuit decided that CAIR violated the CAA but allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaces CAIR with a new rule consistent with the Court's decision. In July 2011, the EPA finalized CSAPR, to replace CAIR, requiring reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit and was ultimately vacated by the Court on August 21, 2012. The Court has ordered the EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. On April 29, 2014 the U.S. Supreme Court reversed the D.C Circuit decision vacating CSAPR and generally upheld the EPA's authority under the CAA to establish the regulatory structure underpinning CSAPR. Depending on the outcome of further proceedings in this matter and how the EPA and the states implement the final rules, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants stations. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield stations. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. MATS was challenged in the U.S. Court of Appeals for the D.C. Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. On April 15, 2014, MATS was upheld by the U.S. Court of Appeals for the D.C. Circuit, however, the Court refused to decide FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers due to a January 2013 petition for reconsideration still pending but not addressed by EPA. Depending on the outcome of further appeals, if any, and how the MATS are ultimately implemented, FirstEnergy's total cost of compliance with MATS is currently estimated to be approximately $465 million (Competitive Energy Services segment of $240 million and Regulated Distribution segment of $225 million).

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island were deactivated. FG entered into RMR arrangements with PJM for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015, when they are scheduled to be deactivated. In February 2014, PJM notified FG that Eastlake Units 1-3 and Lake Shore Unit 18 will be released from RMR status as of September 15, 2014. As of October 9, 2013, the Hatfield's Ferry and Mitchell stations were also deactivated.

FirstEnergy and FES have various long-term coal transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. FE and FES have asserted force majeure defenses for delivery shortfalls under certain agreements, and are in discussion with the applicable counterparties. As to two agreements, FE and FES have settled monetary claims for damages for the failure to take minimum quantities for the calendar year 2012 by the payment of approximately $70 million, and agreed to pay liquidated damages for delivery shortfalls for 2013 and 2014. FE and FES recorded $67 million in liquidated damages in the fourth quarter of 2013, associated with estimated 2013 delivery shortfalls, which were paid in the first quarter of 2014. Additionally, in January 2014, FE and FES reached an agreement in principle with Mepco Holdings LLC to terminate a contract for future coal deliveries to Hatfield for $18 million, which was approved by the United States Bankruptcy Court on February 26, 2014. If FE and FES fail to reach a resolution with applicable counterparties for coal transportation agreements associated with the deactivated plants or unresolved aspects of the transportation agreements and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses do not excuse delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. If that were to occur, FE and FES are unable to estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies to reduce GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. In his 2013 State of the Union address, President Obama called for Congressional action on GHG emissions indicating his administration will take action in the event Congress fails to act. In June 2013, the President's Climate Action Plan outlined goals to: (1) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (2) prepare the United States for the impacts of climate change; and (3) lead international efforts to combat global climate change and prepare for its impacts. GHG emissions have already been reduced by 10% between 2005 and 2012 according to an April, 2014 EPA Report. Due to plant deactivations and increased efficiencies, FirstEnergy anticipates

its CO2 emissions will be reduced 25% below 2005 levels by 2016, exceeding the President's Climate Action Plan goals both in terms of timing and reduction levels.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required the measurement and reporting of GHG emissions commencing in 2010. In December 2009, the EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act." The EPA's finding concludes that concentrations of several key GHGs increase the threat of climate change and may be regulated as "air pollutants" under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of CO_2 equivalents for existing facilities under the CAA's PSD program. On April 13, 2012, the EPA proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units that are larger than 25 MW, which were ultimately withdrawn. On June 25, 2013, a Presidential memorandum directed the EPA to complete, in a timely fashion, proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units, starting with re-proposal by September 20, 2013. The memorandum further directed the EPA to propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel generating units. On September 20, 2013, the EPA proposed a new source performance standard, which would not apply to any existing, modified, or reconstructed fossil fuel generating units, of 1,000 lbs. CO_2/MWH for large natural gas fired units (> 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for other natural gas fired units (≤ 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for fossil fuel fired units which would require partial carbon capture and storage. On October 15, 2013, the U.S. Supreme Court agreed to review a June 2012 D.C. Circuit Court of Appeals decision upholding the EPA's May 2010 regulations to decide a single narrow question: "Whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases?" Oral argument was held on February 24, 2014. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. In 1997, the U.S. Senate passed the Byrd-Hagel resolution by a unanimous vote of 95-0. The resolution stated that it is the sense of the Senate that the United States should not be a signatory to any protocol to, or other agreement regarding, the United Nations Framework Convention on Climate Change which would mandate new commitments to limit or reduce GHG emissions, unless the protocol or other agreement also mandates new specific scheduled commitments to limit or reduce GHG emissions for developing country parties within the same compliance period, or would not result in serious harm to the economy of the United States. A December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement that recognized the scientific view that the increase in global temperature should be below two degrees Celsius; includes a commitment by developed countries to provide funds, approaching $30 billion over three years with a goal of increasing to $100 billion by 2020; and establishes the "Green Climate Fund" to support mitigation, adaptation, and other climate-related activities in developing countries. To the extent that they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia and the United States, would commit to quantified economy-wide emissions targets by 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification. In December 2010, the U.N. Climate Change Conference in Cancun, Mexico resulted in an acknowledgment to reduce emissions from industrialized countries by 25 to 40 percent from 1990 emissions by 2020 and support enhanced action on climate change in the developing world. In December 2011 the U.N. Climate Change Conference in Durban, South Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the "Durban Platform for Enhanced Action". This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020. In December 2012, the U.N. Climate Change Conference in Doha, Qatar, resulted in countries agreeing to a new commitment period under the Kyoto Protocol beginning in 2020. The new Doha Amendment to establish a second commitment period requires the ratification of three-quarters of the parties to the Kyoto Protocol before it becomes effective. In November 2013, the U.N. Climate Change Conference in Warsaw, Poland advanced negotiations of a new global agreement to reduce GHG emissions by 2015. FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

In 2004, the EPA established new performance standards under Section 316(b) of the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment

(which occurs when aquatic life is drawn into a facility's cooling water system). In 2007, the U.S. Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and the EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit's opinion and decided that Section 316(b) of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the CWA to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. On April 16, 2014, counsel for EPA informed the United States District Court in which a settlement agreement with certain NGOs set April 17, 2014 as a deadline for finalizing the Section 316(b) regulation that an additional 29 days would be needed to finalize the Section 316(b) regulation by May 16, 2014. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant's water intake channel to divert fish away from the plant's water intake system. Depending on the results of such studies and the EPA's further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

On April 19, 2013, the EPA proposed regulatory changes to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423). The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the Agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by September 30, 2015, under a consent decree entered by a U.S. District Court and the treatment obligations are proposed to phase-in as waste water discharge permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule, the future costs of compliance with these standards may require material capital expenditures.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin Plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals or estimate the possible loss or range of loss.

In December 2010, PA DEP submitted its CWA 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. In May 2011, the EPA agreed with PA DEP's recommended sulfate impairment designation which requires the development of a TMDL limit for the river, a process that will take PA DEP approximately five years. Based on the stringency of the TMDL, MP may incur significant costs to reduce sulfate discharges into the Monongahela River if the NPDES permit for the coal-fired Fort Martin plant in West Virginia is required to be modified or renewed to include more stringent effluent limitations for sulfate. However, the Hatfield's Ferry and Mitchell Plants in Pennsylvania that discharge into the Monongahela River were deactivated on October 9, 2013.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the possible loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2009, in an advance notice of public rulemaking, the EPA asserted that the large volumes of CCRs produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of CCRs, including the option of regulation as a special waste under the EPA's hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of CCRs. On April 19, 2013, the EPA stated it would "align" its proposed CCR regulations with revised waste water discharge effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) that were proposed on that date. On July 25, 2013, the House of Representatives passed H.R. 221 that would require CCRs to be regulated under Subtitle D of RCRA, as non-hazardous. On January 29, 2014, EPA agreed to take final action by December 19, 2014 on whether or not to pursue the proposed non-hazardous waste option for regulating CCRs in a Consent Decree to be filed in pending litigation. Depending on the content of the EPA's final effluent limitations rule, the specifics of any "alignment", whether EPA chooses to pursue the non-hazardous or hazardous waste option and the potential enactment of legislation, the future costs of compliance with such standards may require material capital expenditures.

On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified Consent Decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified Consent Decree also required payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On February 1, 2013, FG submitted a Feasibility Study analyzing various technical issues relevant to the closure of LBR. On March 28, 2013, FG submitted to the PA DEP a Closure Plan Major Permit Modification Application which provides for placing a final cap over LBR that would require 15 years to fully implement following the closure of LBR. The estimated cost for the proposed closure plan is $234 million, including environmental and other post closure costs. On October 3, 2013, the PA DEP issued a technical deficiency letter citing four main deficiencies with the Closure Plan: (1) seeking to accelerate the 15 year period proposed by FG for closure activities to complete closure in 9 years by commencing closure activities prior to 2017 as proposed by FG; (2) seeking to extend bond closure and post closure activities beyond the 45 years proposed by FG; (3) seeking active dewatering of the CCBs in areas where there are seeps impacted by the Impoundment; and (4) seeking an abatement plan for groundwater impacted by arsenic. FG responded to the PA DEP on December 3, 2013, and as a result of the Closure Plan, FG increased its ARO for LBR by $163 million in 2013. On April 3, 2014, PA DEP issued a permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizes FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCBs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield Plant is pursuing several options for its CCBs following December 31, 2016, and on January 23, 2013, announced a plan for beneficial use of its CCBs for mine reclamation in LaBelle, Pennsylvania. In June 2013, a complaint filed in the U.S. District Court for the Western District of Pennsylvania, alleges the LaBelle site is in violation of RCRA and state laws. In addition, on December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR.

On October 10, 2013 and December 5, 2013, complaints were filed on behalf of approximately 50 individuals against FE, FG and FES in the U.S. District Court for the Northern District of West Virginia and approximately 15 individuals against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages for alleged property damage, bodily injury and emotional distress related to the LBR CCB Impoundment. The complaints state claims for private nuisance, negligence, negligence per se, reckless conduct and trespass related to alleged groundwater contamination and odors emanating from the Impoundment. FE, FG and FES believe the claims are without merit and intend to vigorously defend themselves against the allegations made in the complaints, but, at this time, are unable to predict the outcome of the above matter or estimate the possible loss or range of loss.

FirstEnergy's future cost of compliance with any CCR regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

Certain of FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of March 31, 2014 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $129 million have been accrued through March 31, 2014. Included in the total are accrued liabilities of approximately $82 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of March 31, 2014, FirstEnergy had approximately $2.3 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDT fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDT. FE maintains a $125 million parental guaranty relating to a potential shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry. FE also maintains an $11 million parental guaranty in support of the decommissioning of the spent fuel storage facilities located at its Davis-Besse and Perry nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranty, as appropriate. By a letter dated March 28, 2013, FENOC informed the NRC that the nuclear decommissioning parental guarantee would be increased to $155 million during the second quarter of 2014. Moreover, a new parental guarantee for the Beaver Valley spent fuel storage facility of $9.5 million would also be put in place.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. A NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. On July 9, 2012, the petitioners' proposed a contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding. In an order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance. The ASLB has suspended further consideration of the petitioners' proposed contention on the environmental impacts of spent fuel storage at Davis-Besse. The NRC Staff issued Waste Confidence Draft Generic Environmental Impact Statement and published a proposed rule on this subject in September of 2013. Other contentions proposed by the petitioners in this proceeding have been rejected by the ASLB. On February 18, 2014, Beyond Nuclear and Don't Waste Michigan, two of the petitioners in the Davis-Besse license renewal proceeding, requested that the NRC institute a rulemaking on the environmental impacts of high density spent fuel storage and mitigation alternatives. On February 27, 2014, these petitioners requested a suspension of the licensing decision in the Davis-Besse license renewal proceeding to allow the NRC to complete this rulemaking. On March 21, 2014, both FENOC and the NRC opposed the request for a suspension. On April 21, 2014, the Intervenors proposed an additional contention in the license renewal proceeding related to the shield building.

As part of routine inspections of the concrete shield building at Davis-Besse Nuclear Power Station in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. The shield building is a 2 1/2-foot thick reinforced concrete structure that provides biological shielding, protection from natural phenomena including wind and tornadoes and additional shielding in the event of an accident. FENOC then expanded its sample size to include all of the existing core bores in the shield building. These inspections, which are now complete, identified additional subsurface cracking that was determined to be pre-existing, but only now identified with the aid of improved inspection technology. These inspections also revealed that the cracking condition has propagated a small amount in select areas. Preliminary analysis of the inspections results confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions.

On February 1, 2014 the Davis-Besse Nuclear Power station entered an outage to install two new steam generators, replace about a third of the unit’s 177 fuel assemblies and perform numerous safety inspections and preventative maintenance activities. These activities, including amounts spent in prior years in preparation for this outage, represent an investment of approximately $600 million by FES at Davis Besse. During the preliminary stages of the outage an area of concrete that was not filled to the expected thickness within the shield building wall was discovered at the top of the temporary construction opening that was created as part of the 2011 outage. The 2011 temporary construction opening was created to install the new reactor head. FENOC has assessed the as-found condition of the concrete and has determined the shield building would have performed its design functions. This condition within the shield building wall was repaired to conform to its original design configuration.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FENOC's nuclear facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal. Anker WV entered into a long term Coal Sales Agreement with AE Supply and MP for the supply of coal to the Harrison generating facility. Prior to the time of trial, ICG was dismissed as a defendant by the Court, which issue can be the subject of a future appeal. As a result of defendants' past and continued failure to supply the contracted coal, AE Supply and MP have incurred and will continue to incur significant additional costs for purchasing replacement coal. A non-jury trial

was held from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they have incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. Defendants primarily claim that their performance is excused under a force majeure clause in the coal sales agreement and presented evidence at trial that they will continue to not provide the contracted yearly tonnage amounts. On May 2, 2011, the court entered a verdict in favor of AE Supply and MP for $104 million ($90 million in future damages and $14 million for replacement coal/interest). On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that the defendants still owed future damages, it remanded the calculation of those damages back to the trial court. The specific amount of those future damages is not known at this time, but they are expected to be calculated at a market price of coal that is significantly lower than the price used by the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on November 19, 2012. On July 2, 2013, the Petition for Allowance of Appeal was denied and in the second quarter of 2013 the now final past damage award of $15.5 million (including interest) was recognized. The case was sent back to the trial court to recalculate the future damages only and is currently in the discovery phase. A damages hearing is scheduled for May 13-14, 2014, and a ruling is expected in the fourth quarter of 2014.

Other Legal Matters

In 2010, a lawsuit was filed in Allegheny County Court of Common Pleas by Michael Goretzka, for wrongful death and negligence after his wife was fatally electrocuted when she contacted a downed power line. The trial resulted in a verdict against WP and the parties settled this matter. WP's portion of the settlement was covered by insurance subject to the remainder of its deductible. On May 30, 2012, the PPUC's Bureau of Investigation and Enforcement (I&E) filed a Formal Complaint at the PPUC regarding this matter. On February 13, 2013, WP and I&E filed a Joint Petition for Full Settlement that includes, among other things, WP's agreement to conduct an infrared inspection of its primary distribution system, modify certain training programs, and pay an $86,000 civil penalty, which settlement is subject to PPUC approval. On August 29, 2013, the PPUC entered an Order granting the Goretzka family limited party status for the sole purpose of submitting comments to the settlement and issuing the settlement for comment by the parties. On September 16, 2013, the Goretzka family filed Limited Objections to the settlement. Reply comments were filed by WP on September 30, 2013. The PPUC entered an Opinion and Order on January 9, 2014 approving the Settlement with limited modifications regarding the frequency of refresher training and reporting obligations. WP filed a letter on January 17, 2014 accepting those modifications and noting its intent to begin implementation of the settlement terms.

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 9, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. In cases where FirstEnergy determines that it is not probable, but reasonably possible that it has a material obligation, it discloses such obligations and the possible loss or range of loss if such estimate can be made. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on any of the matters referenced above, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

11. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FG completed a sale and leaseback transaction for its undivided interest in Bruce Mansfield Unit 1. FES has fully and unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FG, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty. This transaction is classified as an operating lease for FES and FirstEnergy and as a financing lease for FG.

The Condensed Consolidating Statements of Income and Comprehensive Income for the three months ended March 31, 2014 and 2013, Condensed Consolidating Balance Sheets as of March 31, 2014 and December 31, 2013, and Condensed Consolidating Statements of Cash Flows for the three months ended March 31, 2014 and 2013, for FES (parent and guarantor), FG and NG (non-guarantor) are presented below. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FG and NG are, therefore, reflected in FES' investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Three Months Ended March 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 1,797	$ 315	$ 362	$ (645)	$ 1,829
OPERATING EXPENSES:					
Fuel	—	272	47	—	319
Purchased power from affiliates	645	—	64	(645)	64
Purchased power from non-affiliates	1,025	4	—	—	1,029
Other operating expenses	228	62	150	12	452
Provision for depreciation	2	29	43	—	74
General taxes	21	11	7	—	39
Total operating expenses	1,921	378	311	(633)	1,977
OPERATING INCOME (LOSS)	(124)	(63)	51	(12)	(148)
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(3)	(1)	(1)	—	(5)
Investment income	1	1	21	(3)	20
Miscellaneous income, including net income from equity investees	103	—	—	(103)	—
Interest expense — affiliates	(3)	(1)	(1)	3	(2)
Interest expense — other	(14)	(24)	(13)	15	(36)
Capitalized interest	—	1	11	—	12
Total other income (expense)	84	(24)	17	(88)	(11)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(40)	(87)	68	(100)	(159)
INCOME TAXES (BENEFITS)	(52)	(31)	26	1	(56)
INCOME (LOSS) FROM CONTINUING OPERATIONS	12	(56)	42	(101)	(103)
Discontinued operations (net of income taxes of $70) (Note 13)	—	116	—	—	116
NET INCOME	$ 12	$ 60	$ 42	$ (101)	$ 13
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 12	$ 60	$ 42	$ (101)	$ 13
OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	(5)	(4)	—	4	(5)
Amortized gain on derivative hedges	(2)	—	—	—	(2)
Change in unrealized gain on available-for-sale securities	19	—	19	(19)	19
Other comprehensive income (loss)	12	(4)	19	(15)	12
Income taxes (benefits) on other comprehensive income (loss)	4	(2)	7	(5)	4
Other comprehensive income (loss), net of tax	8	(2)	12	(10)	8
COMPREHENSIVE INCOME	$ 20	$ 58	$ 54	$ (111)	$ 21

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Three Months Ended March 31, 2013	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 1,496	$ 531	$ 440	$ (943)	$ 1,524
OPERATING EXPENSES:					
Fuel	—	247	53	—	300
Purchased power from affiliates	1,013	—	62	(943)	132
Purchased power from non-affiliates	505	1	—	—	506
Other operating expenses	162	74	131	12	379
Provision for depreciation	1	31	44	(1)	75
General taxes	20	11	6	—	37
Total operating expenses	1,701	364	296	(932)	1,429
OPERATING INCOME (LOSS)	(205)	167	144	(11)	95
OTHER INCOME (EXPENSE):					
Loss on debt redemption	(71)	—	—	—	(71)
Investment income	1	—	18	(2)	17
Miscellaneous income, including net income from equity investees	192	1	—	(191)	2
Interest expense — affiliates	(2)	(1)	(1)	3	(1)
Interest expense — other	(25)	(28)	(15)	16	(52)
Capitalized interest	—	—	9	—	9
Total other income (expense)	95	(28)	11	(174)	(96)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(110)	139	155	(185)	(1)
INCOME TAXES (BENEFITS)	(112)	51	58	3	—
INCOME (LOSS) FROM CONTINUING OPERATIONS	2	88	97	(188)	(1)
Discontinued operations (net of income taxes of $2) (Note 13)	—	3	—	—	3
NET INCOME	$ 2	$ 91	$ 97	$ (188)	$ 2
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 2	$ 91	$ 97	$ (188)	$ 2
OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	(6)	(5)	—	5	(6)
Amortized gain on derivative hedges	(1)	—	—	—	(1)
Change in unrealized gain on available for sale securities	5	—	5	(5)	5
Other comprehensive income (loss)	(2)	(5)	5	—	(2)
Income taxes (benefits) on other comprehensive income (loss)	(1)	(2)	2	—	(1)
Other comprehensive income (loss), net of tax	(1)	(3)	3	—	(1)

COMPREHENSIVE INCOME	$ 1	$ 88	$ 100	$ (188)	$ 1

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of March 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 2	$ —	$ —	$ 2
Receivables-					
Customers	583	—	—	—	583
Affiliated companies	278	185	180	(274)	369
Other	60	18	73	—	151
Notes receivable from affiliated companies	457	449	230	(921)	215
Materials and supplies	63	148	216	—	427
Derivatives	244	—	—	—	244
Collateral	544	—	—	—	544
Prepayments and other	100	79	—	—	179
	2,329	881	699	(1,195)	2,714
PROPERTY, PLANT AND EQUIPMENT:					
In service	106	6,148	6,925	(383)	12,796
Less — Accumulated provision for depreciation	30	1,978	3,038	(189)	4,857
	76	4,170	3,887	(194)	7,939
Construction work in progress	26	130	1,200	—	1,356
	102	4,300	5,087	(194)	9,295
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,323	—	1,323
Investment in affiliated companies	5,891	—	—	(5,891)	—
Other	—	11	—	—	11
	5,891	11	1,323	(5,891)	1,334
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	—	105	—	(105)	—
Customer intangibles	91	—	—	—	91
Goodwill	23	—	—	—	23
Property taxes	—	11	19	—	30
Unamortized sale and leaseback costs	—	—	—	197	197
Derivatives	65	—	—	—	65
Other	72	223	9	(154)	150
	251	339	28	(62)	556
	$ 8,573	$ 5,531	$ 7,137	$ (7,342)	$ 13,899
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 1	$ 120	$ 366	$ (22)	$ 465
Short-term borrowings-					
Affiliated companies	636	283	—	(919)	—
Other	550	5	—	—	555
Accounts payable-					
Affiliated companies	373	19	240	(305)	327
Other	183	112	—	—	295
Accrued taxes	3	68	38	(12)	97
Derivatives	159	—	—	—	159

Other	51	62	21	80	214
	1,956	669	665	(1,178)	2,112
CAPITALIZATION:					
Total equity	5,807	2,343	3,548	(5,865)	5,833
Long-term debt and other long-term obligations	712	2,094	931	(1,186)	2,551
	6,519	4,437	4,479	(7,051)	8,384
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	850	850
Accumulated deferred income taxes	11	—	763	36	810
Asset retirement obligations	—	188	841	—	1,029
Retirement benefits	22	167	—	—	189
Derivatives	36	—	—	—	36
Other	29	70	389	1	489
	98	425	1,993	887	3,403
	$ 8,573	$ 5,531	$ 7,137	$ (7,342)	$ 13,899

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of December 31, 2013	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 2	$ —	$ —	$ 2
Receivables-					
Customers	539	—	—	—	539
Affiliated companies	938	787	227	(916)	1,036
Other	52	12	17	—	81
Notes receivable from affiliated companies	203	23	683	(909)	—
Materials and supplies	76	159	213	—	448
Derivatives	165	—	—	—	165
Collateral	136	—	—	—	136
Prepayments and other	52	50	7	—	109
	2,161	1,033	1,147	(1,825)	2,516
PROPERTY, PLANT AND EQUIPMENT:					
In service	104	6,105	6,645	(382)	12,472
Less — Accumulated provision for depreciation	28	1,953	2,962	(188)	4,755
	76	4,152	3,683	(194)	7,717
Construction work in progress	23	148	1,137	—	1,308
	99	4,300	4,820	(194)	9,025
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,276	—	1,276
Investment in affiliated companies	5,801	—	—	(5,801)	—
Other	—	11	—	—	11
	5,801	11	1,276	(5,801)	1,287
ASSETS HELD FOR SALE	—	122	—	—	122
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	—	131	—	(131)	—
Customer intangibles	95	—	—	—	95
Goodwill	23	—	—	—	23
Property taxes	—	15	26	—	41
Unamortized sale and leaseback costs	—	—	—	168	168
Derivatives	53	—	—	—	53
Other	81	228	18	(155)	172
	252	374	44	(118)	552
	$ 8,313	$ 5,840	$ 7,287	$ (7,938)	$ 13,502
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 1	$ 367	$ 547	$ (23)	$ 892
Short-term borrowings-					
Affiliated companies	977	212	151	(909)	431
Other	—	4	—	—	4
Accounts payable-					
Affiliated companies	741	400	362	(738)	765
Other	94	196	—	—	290
Accrued taxes	204	23	23	(184)	66

Derivatives	110	—	—	—	110
Other	70	63	18	46	197
	2,197	1,265	1,101	(1,808)	2,755
CAPITALIZATION:					
Total equity	5,312	2,283	3,493	(5,776)	5,312
Long-term debt and other long-term obligations	712	1,860	742	(1,184)	2,130
	6,024	4,143	4,235	(6,960)	7,442
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	858	858
Accumulated deferred income taxes	32	—	736	(27)	741
Asset retirement obligations	—	187	828	—	1,015
Retirement benefits	22	163	—	—	185
Derivatives	14	—	—	—	14
Other	24	82	387	(1)	492
	92	432	1,951	830	3,305
	$ 8,313	$ 5,840	$ 7,287	$ (7,938)	$ 13,502

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Three Months Ended March 31, 2014	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (450)	$ 87	$ 51	$ —	$ (312)
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	235	182	—	417
Short-term borrowings, net	209	72	—	(161)	120
Equity contribution from parent	500	—	—	—	500
Redemptions and Repayments-					
Long-term debt	—	(248)	(197)	—	(445)
Short-term borrowings, net	—	—	(151)	151	—
Other	(1)	(2)	(1)	—	(4)
Net cash provided from (used for) financing activities	708	57	(167)	(10)	588
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(2)	(28)	(268)	—	(298)
Nuclear fuel	—	—	(55)	—	(55)
Proceeds from asset sales	—	307	—	—	307
Sales of investment securities held in trusts	—	—	423	—	423
Purchases of investment securities held in trusts	—	—	(438)	—	(438)
Loans to affiliated companies, net	(254)	(425)	454	10	(215)
Other	(2)	2	—	—	—
Net cash provided from (used for) investing activities	(258)	(144)	116	10	(276)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$ —	$ 2	$ —	$ —	$ 2

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Three Months Ended March 31, 2013	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (529)	$ 298	$ 36	$ —	$ (195)
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	894	—	586	(778)	702
Redemptions and Repayments-					
Long-term debt	(369)	(107)	—	—	(476)
Short-term borrowings, net	—	(76)	—	76	—
Tender premiums	(67)	—	—	—	(67)
Other	—	(1)	—	—	(1)
Net cash provided from financing activities	458	(184)	586	(702)	158
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(5)	(138)	(74)	—	(217)
Nuclear fuel	—	—	(27)	—	(27)
Proceeds from asset sales	—	17	—	—	17
Sales of investment securities held in trusts	—	—	252	—	252
Purchases of investment securities held in trusts	—	—	(265)	—	(265)
Loans to affiliated companies, net	75	7	(508)	702	276
Other	1	—	—	—	1
Net cash used for investing activities	71	(114)	(622)	702	37
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	3	—	—	3
Cash and cash equivalents at end of period	$ —	$ 3	$ —	$ —	$ 3

12. SEGMENT INFORMATION

FirstEnergy continues to have three reportable operating segments - Regulated Distribution, Regulated Transmission and Competitive Energy Services. The external reporting is consistent with the internal financial reporting used by FirstEnergy's Chief Executive Officer (its chief operating decision maker) to regularly assess the performance of the business and allocate resources.

Financial information for each of FirstEnergy's reportable segments is presented in the tables below. FES does not have separate reportable operating segments.

The Regulated Distribution segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also includes regulated electric generation facilities in West Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. Its results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls approximately 3,780 MWs of generation capacity.

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP) and the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned project regulatory asset, these revenues are derived from transmission services provided pursuant to the PJM open access transmission tariff to LSEs. Its results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Competitive Energy Services segment, through FES and AE Supply, supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls approximately 14,000 MWs of capacity, including 885 MWs of capacity subject to RMR arrangements with PJM. This segment also purchases electricity to meet sales obligations. The segment's net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs charged by PJM to deliver energy to the segment's customers.

The Other/Corporate Segment contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment. Reconciling adjustments primarily consist of elimination of intersegment transactions.

Segment Financial Information

Three Months Ended	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other/Corporate	Reconciling Adjustments	Consolidated
			(In millions)			
March 31, 2014						
External revenues	$ 2,552	$ 187	$ 1,522	$ (35)	$ (37)	$ 4,189
Internal revenues	—	—	249	—	(249)	—
Total revenues	2,552	187	1,771	(35)	(286)	4,189
Depreciation, amortization and deferrals	131	33	91	11	—	266
Investment income	15	—	14	3	(10)	22
Interest expense	151	25	46	43	—	265
Income taxes (benefits)	125	30	(73)	(26)	(8)	48
Income (loss) from continuing operations	214	51	(124)	(32)	13	122
Discontinued operations, net of tax	—	—	86	—	—	86
Net income (loss)	214	51	(38)	(32)	13	208
Total assets	27,742	5,584	17,445	457	—	51,228
Total goodwill	5,092	526	800	—	—	6,418
Property additions	269	217	318	17	—	821
March 31, 2013						
External revenues	$ 2,212	$ 176	$ 1,414	$ (27)	$ (52)	$ 3,723
Internal revenues	—	—	216	—	(216)	—
Total revenues	2,212	176	1,630	(27)	(268)	3,723
Depreciation, amortization and deferrals	202	29	110	11	—	352
Investment income	18	—	10	1	(11)	18
Interest expense	135	23	73	27	—	258
Income taxes (benefits)	126	31	(24)	(19)	—	114
Income (loss) from continuing operations	210	51	(42)	(30)	3	192
Discontinued operations, net of tax	—	—	4	—	—	4
Net income (loss)	210	51	(38)	(30)	3	196
Total assets	26,943	4,722	18,328	431	—	50,424
Total goodwill	5,025	526	896	—	—	6,447
Property additions	436	89	283	18	—	826

13. DISCONTINUED OPERATIONS

On September 4, 2013, certain of FirstEnergy subsidiaries applied for authorization from the FERC to sell eleven hydroelectric power stations in Pennsylvania, Virginia and West Virginia to subsidiaries of Harbor Hydro, a subsidiary of LS Power. The asset purchase agreement was entered into on August 23, 2013, and amended and restated as of September 4, 2013. On February 12, 2014, the sale of the hydroelectric power plants to LS Power closed for approximately $394 million (FES - $307 million). The carrying value of the assets sold was $235 million (FES - $122 million), including goodwill of $29 million (FES - $1 million) which was allocated to the hydroelectric plants to be sold.

Pre-tax income for the hydroelectric facilities of $155 million and $6 million (FES - $186 million and $5 million) for the three months ended March 31, 2014 and 2013, respectively, were reported in FirstEnergy's and FES' Consolidated Statement of Income as discontinued operations. Included in income from discontinued operations in the three months ended March 31, 2014, was a pre-tax gain on the sale of assets of $142 million (FES - $177 million). Revenues for the hydroelectric facilities of $5 million and $6 million (FES - $5 million and $6 million) for the three months ended March 31, 2014 and 2013, respectively, are reported in FirstEnergy's and FES' Consolidated Statement of Income as discontinued operations.

Item 2. Management's Discussion and Analysis of Registrant and Subsidiaries

FIRSTENERGY CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

Net income in the first quarter of 2014 was $208 million, or basic earnings of $0.50 per share of common stock ($0.49 diluted), compared with net income of $196 million, or basic and diluted earnings of $0.47 per share of common stock in the first quarter of 2013. Net income and changes by segment are summarized below:

	Three Months Ended March 31		
	2014	2013	Increase (Decrease)
	(In millions, except per share)		
Net Income (Loss) By Segment:			
Regulated Distribution	$ 214	$ 210	$ 4
Regulated Transmission	51	51	—
Competitive Energy Services	(38)	(38)	—
Other and reconciling adjustments	(19)	(27)	8
FirstEnergy Corp.	$ 208	$ 196	$ 12
Earnings per share - Basic	$ 0.50	$ 0.47	$ 0.03
Earnings per share - Diluted	$ 0.49	$ 0.47	$ 0.02

Three months ended March 31, 2014 compared to the three months ended March 31, 2013

The Regulated Distribution segment's earnings were impacted by the following:

- Higher distribution deliveries of 5.9% across all customer classes with increases of 10.8% and 5.5% in the residential and commercial class, respectively, primarily reflecting increased weather-related usage resulting from heating degree days that were 17% above 2013.
- Increased regulated generation earnings primarily associated with the Harrison/Pleasants asset transfer in October of 2013. Currently, the Harrison Plant is subject to a temporary surcharge including a return on and return of the plant costs.
- Increased distribution operation and maintenance activities and higher non-deferred storm related restoration expenses.
- Increased depreciation expense, primarily associated with a higher asset base.
- Increased interest expense primarily associated with the financing of the Harrison Plant.

The Regulated Transmission segment's earnings were impacted by the following:

- Higher revenue at ATSI and TrAIL primarily resulting from its annual rate filing effective June 2013.
- Increased operating expenses principally due to higher property taxes, depreciation and operating and maintenance expenses.

The Competitive Energy Services segment's earnings were impacted by the following:

- Higher net cost to serve additional retail load as a result of increased customer demand, primarily due to extreme weather conditions, and higher wholesale energy prices.
- Additional purchased power at higher prices resulting from the timing of unplanned outages and derates.
- Additional purchased power resulting from planned outages.
- Higher PJM ancillary service charges for transmission system reliability, partially offset by "pass-through" revenues to commercial and industrial customers, as well as increased capacity expense primarily due to higher capacity rates.
- Reduced fuel and operating expenses, such as operating and maintenance, depreciation and general taxes, associated with the Harrison/Pleasants asset transfer and the deactivation of certain power plants during 2013, partially offset by the cost of replacing that generation.
- Lower interest expense associated with the redemption and repurchase of long-term debt at FES and AE Supply in 2013.
- Other items impacting the Competitive Energy Services Segment's earnings include the following pre-tax changes:
    - Loss on debt redemptions decreased $110 million primarily related to debt repurchased in the first quarter of 2013.
    - Gains related to commodity mark-to-market adjustments increased $21 million.
    - An increase of $146 million from discontinued operations (before income taxes) primarily associated with a $142 million (pre-tax) gain on the sale of certain hydro facilities.
    - Costs associated with plant closings increased $26 million primarily related to fuel contract terminations.

- Amortization expense associated with purchase accounting adjustments on commodity contracts decreased $9 million.
- PJM charges associated with deactivated plants decreased $15 million.

The Other segment's earnings were impacted by the following:

- A lower effective income tax rate primarily resulting from an increase in AFUDC equity flow-through, changes in state apportionment factors and the elimination of certain future tax liabilities associated with basis differences.
- Increased interest expense due to the issuance of $1.5 billion of FE senior unsecured notes in March of 2013.

Executive Summary

FirstEnergy holds a large and diverse mix of assets, featuring an electric distribution service area and transmission footprint that are among the largest in the nation, as well as a significant competitive generation fleet and retail business.

FirstEnergy's competitive operations, the Competitive Energy Services segment, has been challenged by prolonged weak demand for power, low capacity payments and declining energy prices. Recently, market dynamics within PJM, the region served by the Competitive Energy Services segment's generating fleet, have been unpredictable. Capacity prices resulting from recent annual auctions have produced prices for generators that have been lower than expected. FirstEnergy believes that a thorough review of the rules associated with the capacity auctions, as well as the broader functioning of the PJM market, are necessary to effectuate a robust competitive market. FirstEnergy intends to actively participate in this dialogue at both PJM and FERC.

As a result of the challenging competitive environment, FirstEnergy has begun redirecting its growth strategy to pursue more predictable and sustainable long-term growth opportunities in its regulated businesses.

The centerpiece of this strategy is a $4.2 billion "Energizing the Future" investment plan beginning in 2014 through 2017 to upgrade and expand the transmission system owned by FirstEnergy's Regulated Transmission segment. This program is focused on rebuilding the transmission system, starting with ATSI's system and moving east across FirstEnergy's service territory over time. Also included in the investment are projects that enhance system performance, physical security and add operating flexibility and capacity. These activities began in the first quarter of 2014. FirstEnergy expects to fund these investments through a combination of debt, previously announced equity issuances through stock investment and employee benefit plans, and cash. Due to their investments, Regulated Transmission's earnings are expected to grow modestly over the next two years and then accelerate as the investments are fully recognized in rates. In total, FirstEnergy has identified at least $7 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for growth in the years ahead.

In the territory served by FirstEnergy's distribution segment, Regulated Distribution, the economy has struggled to recover from the recession, and there continues to be weak demand for electricity as evidenced by flat distribution sales over the last three years. However, the location of the Marcellus and Utica shale gas region provides optimism for growth in this portion of Regulated Distribution's service territory over the long term. More than 200 MW of new industrial demand associated with shale gas activity has already come online in FirstEnergy's region, with more than 400 MW of additional planned expansion at customer facilities. These projects alone are expected to result in more industrial growth over the next two years, and a robust pipeline of mid-stream projects represent further opportunities for additional growth, as well as the potential for growth in the residential class.

FirstEnergy is also pursuing regulatory initiatives across its utility footprint, including a rate case application in West Virginia filed in April 2014, as well as the current rate proceeding in New Jersey. FirstEnergy expects to pursue additional targeted rate filings over the next several years as part of its focus on driving stable and predictable growth at its Regulated Distribution segment in the future.

While the Competitive Energy Services segment is not identified as a growth driver in the near term, FirstEnergy is focused on maintaining the value of its competitive business. FirstEnergy has reduced the size and shifted the mix of its generating assets, as well as reduced operating expenses and capital expenditures. As a result, the remaining competitive fleet is more cost-effective, efficient and environmentally sound. While FirstEnergy cannot predict if or when a power price recovery may occur, FirstEnergy believes it has taken appropriate action over the last two years to reposition this business for such a recovery.

In alignment with FirstEnergy's strategy to reposition the Regulated Transmission and Regulated Distribution segments and preserve the competitive business, FirstEnergy will also focus on reducing balance sheet risk, maintaining investment grade metrics, and improving the business risk profile at each of our businesses. Specifically, at the regulated businesses, authority has been obtained for various regulated distribution and transmission subsidiaries to issue or refinance debt. Finally, at the competitive business, FirstEnergy completed the sale of certain hydro assets for approximately $394 million on February 12, 2014. The actions taken in 2013 and those planned for 2014 are expected to support a regulated investment strategy.

Operational Matters

Nuclear Operations

On February 1, 2014 the Davis-Besse Nuclear Power station entered an outage to install two new steam generators, replace about a third of the unit's 177 fuel assemblies and perform numerous safety inspections and preventative maintenance activities. These activities, including amounts spent in prior years in preparation for this outage, represent an investment of approximately $600 million by FES at Davis Besse. During the preliminary stages of the outage an area of concrete that was not filled to the expected thickness within the shield building wall was discovered at the top of the temporary construction opening that was created as part of the 2011 outage. The 2011 temporary construction opening was created to install the new reactor head. FENOC has assessed the as-found condition of the concrete and has determined the shield building would have performed its design functions. This condition within the shield building wall was repaired to conform to its original design configuration.

Beaver Valley Unit 1 returned to service January 29, 2014, following replacement and testing of its main unit transformer, which experienced a fault on January 6, 2014 that resulted in an automatic shutdown of the Unit.

On April 19, 2014, Beaver Valley Unit 2 shut down for scheduled refueling and maintenance. While the unit is off line, one-third of the reactor's 157 fuel assemblies will be replaced and safety inspections will be conducted, including inspections of the unit's reactor vessel head, turbine and electrical generator. In addition, preventative maintenance expected to support continued safe and reliable operations will be performed on major components including pumps, valves and the cooling tower. Beaver Valley Unit 2 will also undertake a number of projects in preparation for replacement of the unit's three steam generators and reactor head in 2017. These activities include installation of a heavy-duty crane system in containment and measurements to support planning for the future replacement.

January 2014 Extreme Weather and Market Conditions

During January 2014, given higher customer usage associated with extreme weather conditions and unit unavailability, including the Beaver Valley Unit 1 outage, FirstEnergy's Competitive Energy Services segment (including FES) was required to purchase higher volumes of power. These extreme weather events caused an increase in the demand for electricity and natural gas throughout the PJM zones. In order to maintain system reliability, PJM incurred higher ancillary service costs, such as synchronous and operating reserves, throughout these extreme conditions. Approximately $800 million in ancillary service charges for the month of January 2014 were billed to all LSEs serving customers throughout the PJM region based on load served, including FES. Certain of these costs are considered a "pass-through" event under existing contracts and revenue of approximately $33 million was recognized associated with commercial and industrial customers in the three month period ended March 31, 2014.

Sammis Planned Outage

In late March of 2014, Sammis Unit 7 came off line to start a planned maintenance outage. Key projects planned for the outage include boiler tubing repairs, blade replacements and other turbine work, a full rewind of the main generator, air heater basket replacements and a booster fan hub rebuild. Other work may take place depending on the outcome of testing scheduled for this outage.

Employee Relations

On April 14, 2014, a lock-out of UWUA Local 180 members ended. The 20-week lock-out started on November 25, 2013. The employees returned to work under the terms of PN's Last, Best and Final Offer of November 6, 2013. The Last, Best and Final Offer contains wage increases, increases in shift premiums and meal allowances, and additional operational improvements, such as a new job classification intended to increase customer service and efficiency. Employees were reinstated to the positions they held prior to the lock-out. The collective bargaining agreement with IBEW Local 272, which represents approximately 300 employees at the Bruce Mansfield Plant expired on February 16, 2014. The collective bargaining agreement with Local 102, which represents 700 employees at WP and PE, expired on April 30, 2013. FirstEnergy continues to engage in negotiations with each of Local 180, 272, and 102, and work continuation plans are in place in the event of a work stoppage.

Regulatory Matters

JCP&L Rate Filing Update

On February 24, 2014, a Stipulation was filed with the NJBPU by JCP&L, the Division of Rate Counsel and NJBPU Staff which will allow recovery of $736 million of JCP&L's $744 million of costs related to the significant weather events of 2011 and 2012. On March 19, 2014, the NJBPU issued an order stating that the stipulation was reasonable and in accordance with the law, that the stipulation struck an appropriate balance between the needs of the customers and JCP&L, and that the 2011 and 2012 major storm costs may be recovered from ratepayers. The manner for recovery of 2011 costs will be decided within the current distribution rate case however the mechanism for recovery of the 2012 storm costs remains to be determined. On March 21, 2014, briefs on recovery of the 2012 storm costs were filed at the NJBPU by JCP&L and the Division of Rate Counsel. Reply briefs were filed on April 1, 2014.

WV Rate Filing

On April 30, 2014, MP and PE filed a rate case requesting a base rate increase of approximately $96 million, or 9.3%. The filing also included a surcharge to recover costs of MP's and PE's vegetation management program in the amount of approximately $48 million. The proposed total rate increase request, including the cost of the vegetation management program, is approximately $144 million, or 14%. MP and PE anticipate a decision from the WVPSC in February 2015.

Financial Matters

Hydro Asset Sales

On February 12, 2014, FirstEnergy completed the sale of 11 hydroelectric power stations to Harbor Hydro Holdings, LLC, a subsidiary of LS Power Equity Partners II, LP, for approximately $394 million. The hydroelectric power stations included in this sale were owned by FG, AE Supply and Green Valley Hydro, LLC and had a total capacity of 527 MW. The sale includes Seneca Pumped Storage (451 MW) in Warren, Pa.; Allegheny Lock & Dam 5 (6 MW) in Schenley, Pa.; Allegheny Lock & Dam 6 (7 MW) in Ford City, Pa.; Lake Lynn (52 MW) in Lake Lynn, Pa.; Millville (3 MW) in Millville, W. Va.; Dam 4 (2 MW) in Shepherdstown, W. Va.; Dam 5 (1.2 MW) in Falling Waters, W.Va.; Warren (750 kW) in Front Royal, Va.; Luray (1.6 MW) in Luray, Va.; and Shenandoah and Newport (860 kW and 1.4 MW, respectively) in Shenandoah, Va. The 35 employees at these power stations were retained by the new owner. Pre-tax income for the hydroelectric facilities of $155 million and $6 million (FES - $186 million and $5 million) for the three months ended March 31, 2014 and 2013, respectively, were reported in FirstEnergy's and FES' Consolidated Statement of Income as discontinued operations. Pre-tax income for the three months ended March 31, 2014 primarily relates to the gain on sale of $142 million (FES - $177 million).

Revolving Credit Facilities and Debt Activity

On March 31, 2014, FE, FES, AE Supply, FET and FE's other borrower subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until March 31, 2019. The FE facility was amended to increase the lending banks' commitments under the facility by $1 billion to a total of $3.5 billion and to increase the individual borrower sublimit for FE by $1 billion to a total of $3.5 billion.The FES/AE Supply facility was amended to decrease the lending banks' commitments by $1 billion to a total of $1.5 billion. The lending banks' commitments under the FET facility remain at $1 billion and that facility was amended to increase ATSI's individual borrower sublimit to $500 million from $100 million and TrAIL's individual borrower sublimit to $400 million from $200 million. FirstEnergy expensed approximately $5 million (FES - $3 million) of unamortized debt expense as a result of the amendments. The amount was included in Loss on Debt Redemptions in the Consolidated Statement of Income in the first quarter of 2014.

On March 31, 2014, FE executed, and fully utilized, a new $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances.

During the first quarter of 2014, FG and NG remarketed approximately $417 million of PCRBs previously held by the companies. Of the total, $182 million was remarketed with a fixed interest rate of 4% per annum with a mandatory put date of June 3, 2019 and $235 million was remarketed with a fixed interest rate of 3.75% per annum with a mandatory put date of December 3, 2018.

In addition, in the first quarter of 2014, FG and NG repurchased approximately $197 million and $16 million of PCRBs, respectively, which were subject to a mandatory tender. The companies are currently holding the PCRB's for remarketing subject to future market and other conditions.

On April 1, 2014, PN and ME repurchased approximately $45 million and $29 million of PCRBs, respectively, which were subject to a mandatory put on such date. The companies are currently holding the PCRB's for remarketing subject to future market and other conditions.

During the first quarter of 2014, AE Supply returned $500 million of capital to FE Corp. Additionally, FE Corp. contributed $500 million of equity to FES.

FIRSTENERGY'S BUSINESS

FirstEnergy continues to have three reportable operating segments - Regulated Distribution, Regulated Transmission and Competitive Energy Services. The external reporting is consistent with the internal financial reporting used by FirstEnergy's Chief Executive Officer (its chief operating decision maker) to regularly assess the performance of the business and allocate resources.

The Regulated Distribution segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also includes regulated electric generation facilities in West Virginia and New Jersey that MP and JCP&L,

respectively, own or contractually control. Its results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls approximately 3,780 MWs of generation capacity.

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP) and the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned project regulatory asset, these revenues are derived from transmission services provided pursuant to the PJM open access transmission tariff to LSEs. Its results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Competitive Energy Services segment, through FES and AE Supply, supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls approximately 14,000 MWs of capacity, including 885 MWs of capacity subject to RMR arrangements with PJM. This segment also purchases electricity to meet sales obligations. The segment's net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs charged by PJM to deliver energy to the segment's customers.

The Competitive Energy Services segment derives its revenues from the sale of generation to direct and governmental aggregation, POLR and wholesale customers. The segment is exposed to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices may be impacted by the prices of other commodities, including coal and natural gas, and energy efficiency and demand response programs, as well as regulatory and legislative actions, such as MATS among other factors. The segment attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies.

The Competitive Energy Services segment economically hedges exposure to price risk on a ratable basis, which is intended to reduce the near-term financial impact of market price volatility. As of March 31, 2014, committed sales for calendar year 2014 are at 98% of the 98.8 million MWH target. For the nine months from April to December 2014, supply from expected generation and committed purchases are approximately 103% of the committed sales under normal weather conditions. As of March 31, 2014, committed sales for 2015 and 2016 are approximately 56 million MWHs and 32 million MWHs, respectively. On average, the Competitive Energy Services segment expects to produce approximately 75 - 80 million MWHs of electricity annually. The Competitive Energy Services segment fulfills the difference between committed sales, which is based on estimated customer usage, assuming normal weather, and electricity generated, through forward contracts and options, generation produced by its peaking units and purchasing power on the wholesale market.

Other and Reconciling Adjustments contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment as well as reconciling adjustments for the elimination of intersegment transactions. See Note 12, Segment Information, of the Combined Notes to Consolidated Financial Statements for further information on FirstEnergy's reportable operating segments.

FirstEnergy considers a variety of factors, including wholesale power prices, in its decision to operate, or not operate, a generating plant. If wholesale power prices represent a lower cost option, FirstEnergy may elect to fulfill its load obligation through purchasing electricity in the wholesale market as opposed to operating a generating unit. The effect of this decision on its results of operations would be to displace higher per unit fuel expense with lower per unit purchased power.

FirstEnergy engages in discussions with various commodity vendors, from time to time, regarding the impact that these and other actions may have on certain of its long-term agreements and FirstEnergy cannot provide assurance that these discussions will be satisfactorily resolved.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's segments. A reconciliation of segment financial results is provided in Note 12, Segment Information, of the Combined Notes to Consolidated Financial Statements. Certain prior year amounts have been reclassified to conform to the current year presentation. These reclassifications include, but are not limited to, the classification of discontinued operations associated with the sale of hydro assets discussed in additional detail in Note 13, Discontinued Operations.

Summary of Results of Operations — First Quarter 2014 Compared with First Quarter 2013

Financial results for FirstEnergy's business segments in the first quarter of 2014 and 2013 were as follows:

First Quarter 2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 2,501	$ 187	$ 1,474	$ (56)	$ 4,106
Other	51	—	48	(16)	83
Internal	—	—	249	(249)	—
Total Revenues	2,552	187	1,771	(321)	4,189
Operating Expenses:					
Fuel	153	—	464	—	617
Purchased power	981	—	723	(249)	1,455
Other operating expenses	627	34	609	(88)	1,182
Provision for depreciation	162	30	91	11	294
Amortization (deferral) of regulatory assets, net	(31)	3	—	—	(28)
General taxes	187	17	54	13	271
Total Operating Expenses	2,079	84	1,941	(313)	3,791
Operating Income (Loss)	473	103	(170)	(8)	398
Other Income (Expense):					
Loss on debt redemptions	—	—	(7)	—	(7)
Investment income	15	—	14	(7)	22
Interest expense	(151)	(25)	(46)	(43)	(265)
Capitalized interest	2	3	12	5	22
Total Other Expense	(134)	(22)	(27)	(45)	(228)
Income (Loss) From Continuing Operations Before Income Taxes	339	81	(197)	(53)	170
Income taxes (benefits)	125	30	(73)	(34)	48
Income (Loss) From Continuing Operations	214	51	(124)	(19)	122
Discontinued Operations, net of tax	—	—	86	—	86
Net Income (Loss)	$ 214	$ 51	$ (38)	$ (19)	$ 208

First Quarter 2013 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 2,155	$ 176	$ 1,372	$ (44)	$ 3,659
Other	57	—	42	(35)	64
Internal	—	—	216	(216)	—
Total Revenues	2,212	176	1,630	(295)	3,723
Operating Expenses:					
Fuel	87	—	543	—	630
Purchased power	875	—	287	(216)	946
Other operating expenses	415	30	526	(89)	882
Provision for depreciation	144	28	110	11	293
Amortization of regulatory assets, net	58	1	—	—	59
General taxes	182	12	60	11	265
Total Operating Expenses	1,761	71	1,526	(283)	3,075
Operating Income	451	105	104	(12)	648
Other Income (Expense):					
Loss on debt redemptions	—	—	(117)	—	(117)
Investment income	18	—	10	(10)	18
Interest expense	(135)	(23)	(73)	(27)	(258)
Capitalized interest	2	—	10	3	15
Total Other Expense	(115)	(23)	(170)	(34)	(342)
Income (Loss) From Continuing Operations Before Income Taxes	336	82	(66)	(46)	306
Income taxes (benefits)	126	31	(24)	(19)	114
Income (Loss) From Continuing Operations	210	51	(42)	(27)	192
Discontinued Operations, net of tax	—	—	4	—	4
Net Income (Loss)	$ 210	$ 51	$ (38)	$ (27)	$ 196

Changes Between First Quarter 2014 and First Quarter 2013 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 346	$ 11	$ 102	$ (12)	$ 447
Other	(6)	—	6	19	19
Internal	—	—	33	(33)	—
Total Revenues	340	11	141	(26)	466
Operating Expenses:					
Fuel	66	—	(79)	—	(13)
Purchased power	106	—	436	(33)	509
Other operating expenses	212	4	83	1	300
Provision for depreciation	18	2	(19)	—	1
Amortization (deferral) of regulatory assets, net	(89)	2	—	—	(87)
General taxes	5	5	(6)	2	6
Total Operating Expenses	318	13	415	(30)	716
Operating Income (Loss)	22	(2)	(274)	4	(250)
Other Income (Expense):					
Loss on debt redemptions	—	—	110	—	110
Investment income	(3)	—	4	3	4
Interest expense	(16)	(2)	27	(16)	(7)
Capitalized interest	—	3	2	2	7
Total Other Expense	(19)	1	143	(11)	114
Income (Loss) From Continuing Operations Before Income Taxes	3	(1)	(131)	(7)	(136)
Income taxes (benefits)	(1)	(1)	(49)	(15)	(66)
Income (Loss) From Continuing Operations	4	—	(82)	8	(70)
Discontinued Operations, net of tax	—	—	82	—	82
Net Income (Loss)	$ 4	$ —	$ —	$ 8	$ 12

Regulated Distribution — First Quarter 2014 Compared with First Quarter 2013

Net income increased $4 million in the first quarter of 2014 compared to the same period of 2013, as more fully described below.

Revenues —

The $340 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended March 31		Increase
	2014	2013	(Decrease)
	(In millions)		
Distribution services	$ 983	$ 972	$ 11
Generation sales:			
Retail	1,104	1,005	99
Wholesale	254	62	192
Total generation sales	1,358	1,067	291
Transmission	160	116	44
Other	51	57	(6)
Total Revenues	$ 2,552	$ 2,212	$ 340

The increase in distribution services revenue is primarily related to higher electric distribution MWH deliveries as described below and an increase in the Ohio Companies' DCR rider revenues, partially offset by a decrease in revenues from the ME and PN NUG riders as a result of the expiration of certain NUG contracts in 2013. Distribution deliveries increased by 5.9% in the first quarter of 2014 compared to the same period of 2013. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Three Months Ended March 31		Increase
	2014	2013	(Decrease)
	(In thousands)		
Residential	16,570	14,956	10.8 %
Commercial	11,028	10,449	5.5 %
Industrial	12,700	12,623	0.6 %
Other	144	147	(2.0)%
Total Electric Distribution MWH Deliveries	40,442	38,175	5.9 %

Higher deliveries to residential and commercial customers primarily reflect increased weather-related usage resulting from heating degree days that were 17% above 2013, and 19% above normal. In the industrial sector, increased sales to steel, automotive and shale gas customers were partially offset by lower sales to chemical customers. For 2014, FirstEnergy continues to expect an increase in industrial sales, with a majority of that increase resulting from shale gas activities. Additionally, FirstEnergy expects growth in the industrial sector beyond 2014 for potential shale gas projects. As new gas fields are developed, the opportunity for additional manufacturing expansion could further support growth.

The following table summarizes the price and volume factors contributing to the $291 million increase in generation revenues for the first quarter of 2014 compared to the same period of 2013:

Source of Change in Generation Revenues	Increase
	(In millions)
Retail:	
Effect of increase in sales volumes	$ 39
Change in prices	60
	99
Wholesale:	
Effect of increase in sales volumes	82
Change in prices	110
	192
Increase in Generation Revenues	$ 291

The increase in retail generation sales volumes was primarily due to increased weather-related usage, as described above, and reduced customer shopping in Maryland, partially offset by higher shopping in other jurisdictions. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 80% from 79% for the Ohio Companies, 65% from 63% for the Pennsylvania Companies and 53% from 52% for JCP&L, and decreased to 41% from 43% for PE. The increase in retail generation prices reflects higher Pennsylvania auction prices, the completion of marginal transmission loss refunds to ME and PN customers in the second quarter of 2013 and a higher generation rate at WP, which includes the recovery of transmission costs effective June 2013. Additionally, the impact of MP's Temporary Transaction Surcharge associated with the Harrison/Pleasants asset transfer was offset by a rate reduction associated with the recovery of ENECs.

The increase in wholesale generation revenues of $192 million in the first quarter of 2014 reflects increased energy prices associated with extreme weather and market conditions in January 2014 and increased volume related to the Harrison/Pleasants asset transfer.

The increase in transmission revenues of $44 million reflects higher FTR revenues at MP related to the extreme weather and market conditions in January 2014 and an increase in the Ohio Companies' NMB transmission rider revenues, partially offset by the termination of WP's network transmission rider effective June 2013. Network transmission costs are now recovered through WP's generation rate.

Operating Expenses —

Total operating expenses increased $318 million primarily due to the following:

- Fuel expense was $66 million higher in 2014 primarily related to increased generation as a result of the Harrison/Pleasants asset transfer.

- Purchased power costs were $106 million higher in 2014 primarily related to higher unit power supply costs during the first quarter of 2014 compared to the same period of 2013, partially offset by lower required volumes as a result of the Harrison/Pleasants asset transfer.

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 117
Change due to decreased volumes	(45)
	72
Purchases from affiliates:	
Change due to increased unit costs	30
Change due to increased volumes	3
	33
Increase in costs deferred	1
Increase in Purchased Power Costs	$ 106

- Other operating expenses increased $212 million primarily due to:
    - Higher transmission expenses of $125 million primarily due to PJM transmission costs associated with higher congestion rates at MP as a result of extreme weather and market conditions in January 2014 and higher transmission volumes as a result of the Harrison/Pleasants asset transfer. The differences between current transmission revenues and transmission costs incurred are deferred for future recovery, resulting in no material impact on current period earnings.
    - Higher distribution operating and maintenance expenses of $64 million primarily due to higher maintenance activities and storm-related restoration costs, including $22 million associated with Winter Storm Nika during the first quarter of 2014 as well as higher pension related costs.
    - Higher energy efficiency expenses of $9 million in Pennsylvania primarily related to smart meter implementation, which are recovered through rates, and
    - Increased regulated generation operating and maintenance expenses of $14 million, reflecting increased costs associated with the Harrison/Pleasants asset transfer and a planned outage at Fort Martin.
- Depreciation expense increased $18 million due to a higher asset base, including $7 million associated with the Harrison/Pleasants asset transfer.
- Amortization (deferral) of regulatory assets decreased $89 million primarily due to higher storm cost deferrals, including $15 million related to Winter Storm Nika, lower default generation service costs recovery in Pennsylvania, a reduction of NUG costs recovery at ME and PN, and increased deferral of energy efficiency program costs, partially offset by lower transmission cost deferrals in Ohio and the completion of marginal transmission loss refunds at ME and PN.
- General taxes increased $5 million primarily due to higher property taxes and an increase in the West Virginia business and occupation tax as a result of the Harrison/Pleasants asset transfer.

Other Expense —

Other expense increased $19 million in the first quarter of 2014 primarily due to higher interest expense at MP as a result of financing the Harrison/Pleasants asset transfer and at JCP&L resulting from new debt issuances in 2013.

Regulated Transmission — First Quarter 2014 Compared with First Quarter 2013

Net income was $51 million in the first quarter of 2014 compared to $51 million in the same period of 2013.

Revenues —

Total revenues increased $11 million principally at ATSI and TrAIL associated with increased rates resulting from their annual rate filing effective June 2013.

Revenues by transmission asset owner are shown in the following table:

Revenues by Transmission Asset Owner	Three Months Ended March 31 2014	2013	Increase (Decrease)
		(In millions)	
ATSI	$ 56	$ 49	$ 7
TrAIL	53	48	5
PATH	4	5	(1)
Utilities	74	74	—
Total Revenues	$ 187	$ 176	$ 11

Operating Expenses —

Total operating expenses increased $13 million principally due to higher property tax, depreciation and other expenses.

Competitive Energy Services — First Quarter 2014 Compared with First Quarter 2013

Net income was unchanged in the first quarter of 2014, compared to the same period of 2013, as more fully described below.

Revenues —

Total revenues increased by $141 million in the first quarter of 2014, compared to the same period of 2013, primarily due to increased Transmission revenue and increased sales volumes in Governmental Aggregation, Mass Market, and POLR and Structured Sales channels. Revenues were also impacted by higher unit prices compared to 2013 as a result of increased channel pricing and ancillary pass-through revenues associated with PJM expenses incurred in January 2014.

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended March 31 2014	2013	Increase (Decrease)
		(In millions)	
Direct	$ 713	$ 710	$ 3
Governmental Aggregation	320	292	28
Mass Market	142	117	25
POLR and Structured	363	351	12
Wholesale	67	71	(4)
Transmission	118	47	71
Other	48	42	6
Total Revenues	$ 1,771	$ 1,630	$ 141

MWH Sales by Channel	Three Months Ended March 31 2014	2013	Increase (Decrease)
		(In thousands)	
Direct	12,841	13,614	(5.7)%
Governmental Aggregation	5,769	5,386	7.1 %
Mass Market	2,126	1,780	19.4 %
POLR and Structured	8,172	6,817	19.9 %
Wholesale	11	228	(95.2)%
Total MWH Sales	28,919	27,825	3.9 %

The following table summarizes the price and volume factors contributing to changes in revenues:

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
			(In millions)		
Direct	$ (40)	$ 43	$ —	$ —	$ 3
Governmental Aggregation	21	7	—	—	28
Mass Market	23	2	—	—	25
POLR and Structured Sales	68	(56)	—	—	12
Wholesale	(6)	—	3	(1)	(4)

The increase in Direct revenues of $3 million resulted from higher unit prices, partially offset by lower sales volumes from large commercial and industrial customers. Direct sales volumes decreased due to Competitive Energy Services' strategy to be more selective in customers targeted in response to the current market environment. The increase in Governmental Aggregation revenues of $28 million primarily reflects increased weather-related usage resulting from heating degree days that were 17% higher than the first quarter of 2013 and higher unit prices. The increase in Mass Market of $25 million resulted from the acquisition of new customers

primarily in Ohio and Pennsylvania, increased weather-related usage and higher unit prices. The Direct, Governmental Aggregation and Mass Market customer base remained at 2.7 million customers as of March 31, 2014. Higher unit prices in each of the above sales channels resulted from increased channel pricing. Additionally, higher Direct unit prices were impacted by approximately $33 million of ancillary pass-through revenues associated with PJM expenses incurred in January 2014 as more fully described below.

The increase in POLR and structured revenues of $12 million was due to higher POLR and structured sales volumes primarily as a result of increased weather-related usage described above. Lower structured unit prices were primarily due to extreme weather and market conditions in January 2014 that reduced the gains on various structured financial sales contracts, partially offset by higher POLR rates associated with recent auctions.

Wholesale revenues decreased $4 million, primarily due to a decrease in short-term (net hourly positions) transactions. The decrease in wholesale sales volumes was due to lower generation available for sale primarily as a result of the Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013, and increased sales volume requirements discussed above.

Transmission revenue increased $71 million due to higher congestion and ancillary revenue associated with additional retail load.

Other revenue increased $6 million primarily due to higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks since the first quarter of 2013. Competitive Energy Services earns lease revenue associated with the equity interests it purchased.

Operating Expenses —

Total operating expenses increased by $415 million in the first quarter of 2014 due to the following:

- Fuel costs decreased $79 million primarily due to lower volumes associated with the Harrison/Pleasants asset transfer, the deactivation of certain power plants in 2013 and lower nuclear generation due to outages, partially offset by higher unit prices and the termination of a coal contract for $18 million.

- Purchased power costs increased $436 million due to higher volumes ($267 million), increased prices ($124 million), and higher capacity expenses ($45 million). Higher purchased volumes were primarily due to increased sales volume requirements and lower available generation due to outages, the Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013. The increase in prices was primarily a result of extreme weather and market conditions in January 2014, partially offset by net gains on financially settled contracts. Increased customer demand that was unhedged and replacement power requirements due to the timing of unplanned outages and derates contributed to purchasing additional volumes at these higher prices. The increase in capacity expense was the result of higher capacity rates primarily in the MAAC zone and increased sales volumes.

- Fossil operating costs decreased $51 million due primarily to lower labor costs resulting from previously deactivated units, the Harrison/Pleasants asset transfer and fewer planned outage days in the first quarter of 2014 as compared to the same period of 2013.

- Nuclear operating costs increased $15 million as a result of higher contractor, materials and equipment costs associated with the refueling outage at Davis-Besse that began on February 1, 2014. In the same period of 2013, there was a refueling outage at Perry that began on March 18, 2013.

- Transmission expenses increased $133 million due primarily to higher operating reserve and market-based ancillary costs associated with the extreme weather and market conditions in January 2014. A portion of these ancillary charges from PJM, which were for system reliability, are able to be passed through to commercial and industrial customers. Additionally, effective June 1, 2013, network expenses associated with POLR sales in Pennsylvania became the responsibility of suppliers.

- General taxes decreased $6 million due primarily to lower payroll taxes as a result of lower labor costs noted above and the Harrison/Pleasants asset transfer, partially offset by higher gross receipts taxes.

- Depreciation expense decreased $19 million primarily due to a reduction in the asset base as a result of the plant deactivations and the Harrison/Pleasants asset transfer noted above.

- Other operating expenses decreased $14 million primarily due to a reduction in mark-to-market expenses on commodity contract positions, partially offset by higher leasehold costs from the Ohio Companies due to increased generation by Perry and increased agent fees associated with the retail business.

Other Expense —

Total other expense in the first quarter of 2014 decreased $143 million compared to the same period of 2013 due to the absence of a $110 million loss on debt redemption in connection with senior notes that were repurchased in 2013, higher investment income of $4 million on NDT investments, and lower net interest expense of $29 million due to debt redemptions.

Discontinued Operations —

Discontinued operations increased net income in the first quarter of 2014 compared to the same period of last year primarily due to a a pre-tax gain of approximately $142 million associated with the sale of hydro assets described above.

Other — First Quarter 2014 Compared with First Quarter 2013

Financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $8 million increase in net income in the first quarter of 2014 compared to the same period of 2013 primarily due to tax benefits resulting from higher AFUDC equity flow-through, changes in state apportionment factors and the elimination of certain future tax liabilities associated with basis differences. This benefit was partially offset by increased interest expense due to the issuance of $1.5 billion of FE senior unsecured notes in March of 2013.

Regulatory Assets

Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent amounts that are expected to be credited to customers through future regulated rates or amounts collected from customers for costs not yet incurred. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions. The following table provides information about the composition of net regulatory assets as of March 31, 2014 and December 31, 2013, and the changes during the three months ended March 31, 2014:

Regulatory Assets (Liabilities) by Source	March 31, 2014	December 31, 2013	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 236	$ 266	$ (30)
Customer receivables for future income taxes	514	518	(4)
Nuclear decommissioning and spent fuel disposal costs	(207)	(198)	(9)
Asset removal costs	(363)	(362)	(1)
Deferred transmission costs	92	112	(20)
Deferred generation costs	360	346	14
Deferred distribution costs	190	194	(4)
Contract valuations	229	260	(31)
Storm-related costs	466	455	11
Other	281	263	18
Total	$ 1,798	$ 1,854	$ (56)

Regulatory assets that do not earn a current return totaled approximately $514 million as of March 31, 2014 primarily related to storm damage costs.

As of March 31, 2014 and December 31, 2013, FirstEnergy had approximately $382 million and $440 million, respectively, of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within Other noncurrent liabilities on the Consolidated Balance Sheets.

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy's business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. In addition to internal sources to fund liquidity and capital requirements for 2014 and beyond, FirstEnergy expects to rely on external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through the issuance of long-term debt and/or equity. FirstEnergy expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets.

In January 2014, FirstEnergy's Board of Directors declared a revised quarterly dividend of $0.36 per share of outstanding common stock. The dividend was paid on March 1, 2014, to shareholders of record at the close of business on February 7, 2014. This revised dividend equates to an indicated annual dividend of $1.44 per share, reduced from the $0.55 per share quarterly dividend ($2.20 per share annually) that FirstEnergy had paid since 2008. In March 2014, FirstEnergy's Board of Directors declared a quarterly dividend of $0.36 per share of outstanding common stock that will be paid on June 1, 2014, to shareholders of record at the close of business on May 7, 2014.

As a result of the challenging competitive environment, FirstEnergy has begun redirecting its growth strategy to pursue more predictable and sustainable long-term growth opportunities in its regulated businesses.

The centerpiece of this strategy is a $4.2 billion "Energizing the Future" investment plan beginning in 2014 through 2017 to upgrade and expand the transmission system owned by FirstEnergy's Regulated Transmission segment. This program is focused on rebuilding the transmission system, starting with ATSI's system and moving east across FirstEnergy's service territory over time. Also included in the investment are projects that enhance system performance, physical security and add operating flexibility and capacity. These activities began in the first quarter of 2014. FirstEnergy expects to fund these investments through a combination of debt, previously announced equity issuances through stock investment and employee benefit plans, and cash. In total, FirstEnergy has identified at least $7 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for growth in the years ahead.

In alignment with FirstEnergy's strategy to reposition the Regulated Transmission and Regulated Distribution segments and preserve the competitive business, FirstEnergy will also focus on reducing balance sheet risk, maintaining investment grade metrics, and improving the business risk profile at each of our businesses. Specifically, at the regulated businesses, authority has been obtained for various regulated distribution and transmission subsidiaries to issue or refinance debt. Finally, at the competitive business, FirstEnergy completed the sale of certain hydro assets for approximately $394 million on February 12, 2014. The actions taken in 2013 and those planned for 2014 are expected to support a regulated investment strategy.

Any financing plans by FirstEnergy, including refinancing of maturing debt and reductions in short-term borrowings, are subject to market conditions and other factors. No assurance can be given that any such financings, refinancings, or reductions in short-term debt, as the case may be, will be completed as anticipated. In addition, FirstEnergy expects to continually evaluate any planned financings, which may result in changes from time to time.

As of March 31, 2014, FirstEnergy's net deficit in working capital (current assets less current liabilities) was due in large part to currently payable long-term debt and short-term borrowings. Currently payable long-term debt as of March 31, 2014, included the following:

Currently Payable Long-Term Debt	(In millions)
PCRBs supported by bank LOCs [1]	$ 415
Unsecured notes	600
FMB	175
Unsecured PCRBs [1]	26
Collateralized lease obligation bonds	91
Sinking fund requirements	103
Other notes	6
	$ 1,416

[1] These PCRBs are classified as currently payable long-term debt because the applicable interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.

Short-Term Borrowings

FirstEnergy had $3,085 million of short-term borrowings as of March 31, 2014, and $3,404 million as of December 31, 2013. FirstEnergy's available liquidity as of April 30, 2014, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	March 2019	$ 3,500	$ 1,629
FES / AE Supply	Revolving	March 2019	1,500	1,031
FET[2]	Revolving	March 2019	1,000	250
		Subtotal	$ 6,000	$ 2,910
		Cash	—	74
		Total	$ 6,000	$ 2,984

[1] FE and the Utilities.
[2] Includes FET, ATSI and TrAIL.

Revolving Credit Facilities

FirstEnergy, FES/AE Supply and FET Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities).On March 31, 2014, FE, FES, AE Supply, FET and FE's other borrower subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until March 31, 2019. The FE facility was amended to increase the lending banks' commitments under the facility by $1 billion to a total of $3.5 billion and to increase the individual borrower sublimit for FE by $1 billion to a total of $3.5 billion.The FES/AE Supply facility was amended to decrease the lending banks' commitments by $1 billion to a total of $1.5 billion. The lending banks' commitments under the FET facility remain at $1 billion and that facility was amended to increase ATSI's individual borrower sublimit to $500 million from $100 million and TrAIL's individual borrower sublimit to $400 million from $200 million. FirstEnergy expensed approximately $5 million (FES - $3 million) of unamortized debt expense as a result of the amendments. The amount was included in Loss on Debt Redemptions in the Consolidated Statement of Income in the first quarter of 2014.

Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio (as defined under each of the Facilities, as amended) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations, as of March 31, 2014:

Borrower	FE Revolving Credit Facility Sublimit	FES/AE Supply Revolving Credit Facility Sublimit	FET Revolving Credit Facility Sublimit	Regulatory and Other Short-Term Debt Limitations
		(In millions)		
FE	$ 3,500	$ —	$ —	$ — [1]
FES	—	1,500	—	— [2]
AE Supply	—	1,000	—	— [2]
FET	—	—	1,000	— [1]
OE	500	—	—	500 [3]
CEI	500	—	—	500 [3]
TE	500	—	—	500 [3]
JCP&L	600	—	—	850 [3]
ME	300	—	—	500 [3]
PN	300	—	—	300 [3]
WP	200	—	—	200 [3]
MP	500	—	—	500 [3]
PE	150	—	—	150 [3]
ATSI	—	—	500	500 [3]
Penn	50	—	—	50 [3]
TrAIL	—	—	400	400 [3]

[1] No limitations.
[2] No limitation based upon blanket financing authorization from the FERC under existing open market tariffs.
[3] Includes amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility, $630 million of the FE Facility and $225 million of the FET Facility, subject to each borrower's sublimit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower's borrowing sub-limit.

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in "pricing grids," whereby the cost of funds borrowed under the Facilities is related to the credit ratings of the company borrowing the funds, other than the FET Facility, which is based on its subsidiaries' credit ratings. Additionally, borrowings under each of the Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million.

As of March 31, 2014, the borrowers were in compliance with the applicable debt to total capitalization ratios under the respective Facilities.

Term Loans

On March 31, 2014, FE executed, and fully utilized, a new $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. Additionally, FE has a $200 million variable rate term loan, due December 31, 2015. Each of the term loans contains covenants and other terms and conditions substantially similar to those of the FE Facility described above, including the same consolidated debt to total capitalization ratio requirement.

FirstEnergy Money Pools

FirstEnergy's utility operating subsidiary companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the first three months of 2014 was 1.68% per annum for the regulated companies' money pool and 1.25% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of March 31, 2014, FirstEnergy's currently payable long-term debt included approximately $415 million ($342 million applicable to FES) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

The LOCs for FirstEnergy's variable interest rate PCRBs outstanding as of March 31, 2014 were issued by the following banks:

Bank	Aggregate Amount [1]	Termination Date	Reimbursements of Draws Due
	(In millions)		
UBS[2]	$ 268	April 2014	April 2014
CitiBank N.A.	164	June 2014	June 2014
The Bank of Nova Scotia[2]	49	April 2014	April 2014
The Bank of Nova Scotia	81	April 2015	April 2015
The Bank of Nova Scotia	96	December 2015	December 2015
Total	$ 658		

(1) Excludes approximately $8 million of applicable interest coverage.
(2) The LOCs for UBS and The Bank of Nova Scotia with a termination date of April 2014 expired in April 2014.

Long-Term Debt Capacity

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. The following table displays FE's and its subsidiaries' credit ratings as of March 31, 2014:

	Senior Secured			Senior Unsecured		
Issuer	**S&P**	**Moody's**	**Fitch**	**S&P**	**Moody's**	**Fitch**
FE	—	—	—	BB+	Baa3	BB+
FES	—	—	—	BBB-	Baa3	BB+
AE Supply	—	—	—	BBB-	Baa3	BB+
AGC	—	—	—	BBB-	Baa3	BBB
ATSI	—	—	—	BBB-	Baa2	BBB+
CEI	BBB+	Baa1	BBB	BBB-	Baa3	BBB-
JCP&L	—	—	—	BBB-	Baa2	BBB
ME	—	—	—	BBB-	Baa2	BBB+
MP	BBB+	Baa1	A-	—	—	—
OE	BBB+	A3	BBB+	BBB-	Baa2	BBB
PN	—	—	—	BBB-	Baa2	BBB
Penn	BBB+	A3	BBB+	—	—	—
PE	BBB+	Baa1	A-	—	—	—
TE	BBB	Baa1	BBB	—	—	—
TrAIL	—	—	—	BBB-	Baa1	BBB+
WP	BBB+	A3	A-	—	—	—

On April 21, 2014, Moody's assigned a Baa3 Issuer Rating to FET and raised TrAIL's senior unsecured rating to A3 from Baa1. On May 1, 2014, Fitch affirmed FE's Issuer Default and senior unsecured debt ratings of BB+. Fitch also affirmed the ratings of FE's subsidiaries as indicated in the table above. The Rating Outlook for all companies is Stable. Fitch expects to withdraw its ratings of FE's subsidiaries in the second quarter of 2014.

Debt capacity is subject to the consolidated debt to total capitalization limits in the Facilities previously discussed. As of March 31, 2014, FE and its subsidiaries could issue additional debt of approximately $4.8 billion and remain within the limitations of the financial covenants required by the Facilities (as amended). As of March 31, 2014, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $4.8 billion given FE's consolidated debt to total capitalization ratio under its Facility, as amended.

Changes in Cash Position

As of March 31, 2014, FirstEnergy had $109 million of cash and cash equivalents compared to $218 million of cash and cash equivalents as of December 31, 2013. As of March 31, 2014 and December 31, 2013, FirstEnergy had approximately $75 million and $103 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

FirstEnergy's consolidated net cash from operating activities was provided by its regulated distribution, regulated transmission and competitive energy services businesses (see Results of Operations above). Net cash used for operating activities was $92 million during the first three months of 2014 compared with $50 million provided from operating activities during the first three months of 2013, as summarized in the following table:

	Three Months Ended March 31		
Operating Cash Flows	**2014**	**2013**	**Increase (Decrease)**
		(In millions)	
Net income	$ 208	$ 196	$ 12
Non-cash charges	378	604	(226)
Working capital and other	(678)	(750)	72
	$ (92)	$ 50	$ (142)

The $142 million decrease in operating cash flows for the first quarter of 2014 compared to the same period of 2013 was primarily due to increased cash posted as collateral due to the extreme weather and market conditions experienced in January of 2014. On April 16, 2014, approximately $275 million of cash collateral was returned to FES as a result of the PJM semi-annual peak market activity calculation reset.

The $226 million decrease in non-cash charges is primarily due to the following:

- $110 million decrease from loss on debt redemptions incurred in 2013 associated with the completion of the FES/AE Supply tender offers and FES debt redemptions.
- $9 million decrease from lower deferred purchased power and other costs primarily due to the expiration of certain NUG agreements.
- $87 million decrease in amortization (deferral) of regulatory assets primarily due to lower default generation service costs recovery in Pennsylvania, partially offset by the completion of marginal transmission loss refunds at ME and PN.
- $47 million increase due to deferred income taxes and investment tax credits.
- $44 million increase in retirement benefits due to reduced payments in 2014 as compared to 2013.
- $82 million decrease associated with discontinued operations primarily as a result of the adjustment to eliminate from operating activities the gain on sale in 2014 of approximately $78 million (after-tax).
- $21 million decrease due primarily to unrealized gains on commodity transactions as described in the Results of Operations above.

The $72 million increase in cash from working capital and other is primarily due to the following:

- $460 million decrease due to cash collateral paid resulting from higher PJM collateral requirements associated with the extreme weather and market conditions in January of 2014.
- $134 million decrease associated with higher customer receivables, primarily as a result of increased weather related usage as described in the Results of Operations above.
- $578 million increase in accounts payable due to the timing of payments to vendors, including payments in 2013 related to restoration costs associated with Hurricane Sandy.
- $120 million increase in customer deposits and changes in other assets and liabilities.
- $27 million decrease in accrued compensation and benefits associated with higher incentive compensation payments in 2014 compared to 2013.

Cash Flows From Financing Activities

In the first three months of 2014, cash provided from financing activities was $498 million compared to $772 million of net cash provided from financing activities during the first three months of 2013. The following table summarizes new debt financing (net of any discounts) and redemptions and repurchases:

	Three Months Ended March 31	
Securities Issued or Redeemed / Repaid	**2014**	**2013**
	(In millions)	
New Issues		
PCRBs	$ 417	$ —
Term Loan	1,050	—
Unsecured Notes	—	1,800
	$ 1,467	$ 1,800
Redemptions / Repayments		
PCRBs	$ (444)	$ —
Senior secured notes	(45)	(17)
Unsecured notes	—	(829)
	$ (489)	$ (846)
Tender premiums paid on debt redemptions	—	(110)
Short-term borrowings, net	$ (319)	$ 181

On March 31, 2014, FE, FES, AE Supply, FET and FE's other borrower subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until March 31, 2019. The FE facility was amended to increase the lending banks' commitments under the facility by $1 billion to a total of $3.5 billion and to increase the individual borrower sublimit for FE by $1 billion to a total of $3.5 billion.The FES/AE Supply facility was amended to decrease the lending banks' commitments by $1 billion to a total of $1.5 billion. The lending banks' commitments under the FET facility remain at $1 billion and that facility was amended to increase ATSI's individual borrower sublimit to $500 million from $100 million and TrAIL's individual borrower sublimit to $400 million from $200 million. FirstEnergy expensed approximately $5 million (FES - $3 million) of unamortized debt expense as a result of the amendments. The amount was included in Loss on Debt Redemptions in the Consolidated Statement of Income in the first quarter of 2014.

On March 31, 2014, FE executed, and fully utilized, a new $1 billion variable rate term loan credit agreement with a maturity date of March 31, 2019. The initial borrowing under the term loan, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances.

During the first quarter of 2014, FG and NG remarketed approximately $417 million of PCRBs previously held by the companies. Of the total, $182 million was remarketed with a fixed interest rate of 4% per annum with a mandatory put date of June 3, 2019 and $235 million was remarketed with a fixed interest rate of 3.75% per annum with a mandatory put date of December 3, 2018.

In addition, in the first quarter of 2014, FG and NG repurchased approximately $197 million and $16 million of PCRBs, respectively, which were subject to a mandatory tender. The companies are currently holding the PCRB's for remarketing subject to future market and other conditions.

On April 1, 2014, PN and ME repurchased approximately $45 million and $29 million of PCRBs, respectively, which were subject to a mandatory put on such date. The companies are currently holding the PCRB's for remarketing subject to future market and other conditions.

During the first quarter of 2014, AE Supply returned $500 million of capital to FE Corp. Additionally, FE Corp. contributed $500 million of equity to FES.

Cash Flows From Investing Activities

Cash used for investing activities in the first three months of 2014 principally represented cash used for property additions. The following table summarizes investing activities for the first three months of 2014 and the comparable period of 2013:

	Three Months Ended March 31		
Cash Used for Investing Activities	**2014**	**2013**	**Increase (Decrease)**
		(In millions)	
Property Additions:			
Regulated distribution	$ 269	$ 436	$ (167)
Regulated transmission	217	89	128
Competitive energy services	318	283	35
Other and reconciling adjustments	17	18	(1)
Nuclear fuel	55	27	28
Proceeds from asset sales	(394)	—	(394)
Investments	(3)	20	(23)
Asset removal costs	39	53	(14)
Other	(3)	1	(4)
	$ 515	$ 927	$ (412)

Net cash used for investing activities during the first three months of 2014 decreased by $412 million compared to the same period of 2013. The decrease was principally due to the proceeds from the sale of the Hydro assets of $394 million.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. The maximum potential amount of future payments FirstEnergy and its subsidiaries could be required to make under these guarantees as of March 31, 2014, was approximately $4.0 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FE's Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts[1]	$ 257
LOC (long-term debt) - interest coverage[2]	5
Deferred compensation arrangements	476
Other[3]	158
	896
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts	76
LOC (long-term debt) - interest coverage[2]	2
FES' guarantee of NG's nuclear property insurance	89
FES' guarantee of FG's sale and leaseback obligations	2,030
Other	10
	2,207
Global Holding facility	350
Surety Bonds	464
LOCs[4]	77
	891
Total Guarantees and Other Assurances	$ 3,994

(1) Issued for open-ended terms, with a 10-day termination right by FirstEnergy.

(2) Reflects the interest coverage portion of LOCs issued in support of floating rate PCRBs with various maturities. The principal amount of floating-rate PCRBs of $658 million, of which $415 million is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.

(3) Includes guarantees of $125 million for nuclear decommissioning funding assurances, $11 million supporting OE's sale and leaseback arrangements, and $22 million for various leases. By a letter dated March 28, 2013, FENOC informed the NRC that the nuclear decommissioning parental guarantee would be increased to $155 million during the second quarter of 2014. Moreover, a new parental guarantee for the Beaver Valley spent fuel storage facility of $9.5 million would also be put in place.

(4) Includes $7 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities, $45 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $25 million pledged in connection with the sale and leaseback of Perry by OE.

FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG, and NG would have claims against each of FES, FG and NG, regardless of whether their primary obligor is FES, FG or NG.

Collateral and Contingent-Related Features

In the normal course of business, FE and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuel, and emission allowances. Certain bilateral agreements and derivative instruments contain provisions that require FE or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FE's or its subsidiaries' credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. The incremental collateral requirement allows for the offsetting of assets and liabilities with the same counterparty, where the contractual right of offset exists under applicable master netting agreements.This posted collateral is used to settle gains or losses on those bilateral agreements or derivatives.

Based on FES' power portfolio exposure as of March 31, 2014, FES has posted collateral of $544 million and AE Supply has posted collateral of $8 million. The Regulated Distribution segment has posted collateral of $28 million. The collateral posted at FES primarily

relates to the extreme weather and market conditions experienced in January of 2014. On April 16, 2014, approximately $275 million of cash collateral was returned to FES as a result of the PJM semi-annual peak market activity calculation reset.

These credit-risk-related contingent features stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a "material adverse event," the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations as of March 31, 2014:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 461	$ 6	$ 49	$ 516
BB+/Ba1 Credit Ratings	$ 497	$ 6	$ 49	$ 552
Full impact of credit contingent contractual obligations	$ 796	$ 58	$ 87	$ 941

Excluded from the preceding chart is the potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Services Segment. As of March 31, 2014, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES and AE Supply would be required to post $111 million and $1 million, respectively.

Other Commitments and Contingencies

FE is a guarantor under a syndicated three-year senior secured term loan facility dated October 18, 2011, as amended, that matures October 18, 2015, under which Global Holding borrowed $350 million. Proceeds from the loan were used to repay Signal Peak's and Global Rail's maturing $350 million syndicated two-year senior secured term loan facility. In addition to FE, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, have also provided their joint and several guarantees of the obligations of Global Holding under the new facility.

In connection with the facility, 69.99% of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with FEV's and WMB Marketing Ventures, LLC's respective 33-1/3% membership interests in Global Holding, are pledged to the lenders as collateral.

FE, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed, most recently as of August 14, 2013, to use their best efforts to refinance the facility no later than July 20, 2015, on a non-recourse basis so that FE's guaranty can be terminated and/or released. If that refinancing does not occur, FE may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the facility in full. In lieu of providing such funding, the co-owners, at FE's option, may provide their several guaranties of Global Holding's obligations under the facility. Since January 1, 2013, FE has received a fee for providing its guaranty. The fee is payable semiannually, and accrues at a rate of 5% per annum on the average daily outstanding aggregate commitments under the facility for each semiannual period.

OFF-BALANCE SHEET ARRANGEMENTS

FES and certain of the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to the Perry Unit 1, Beaver Valley Unit 2, and 2007 Bruce Mansfield Unit 1 sale and leaseback arrangements, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, was $1.1 billion as of March 31, 2014 and primarily relates to the 2007 Bruce Mansfield Unit 1 sale and leaseback arrangement expiring in 2040. From time to time FirstEnergy and these companies enter into discussions with certain parties to the arrangements regarding acquisition of owner participant and other interests. However, FirstEnergy cannot provide assurance that any such acquisitions will occur on satisfactory terms or at all.

In February 2014, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million. As of March 31, 2014, FirstEnergy's leasehold interest was 8.11% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

MARKET RISK INFORMATION

FirstEnergy uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. FirstEnergy's Risk Policy Committee, comprised of members of senior management, provides general oversight for risk management activities throughout the company.

Commodity Price Risk

FirstEnergy is exposed to financial risks resulting from fluctuating commodity prices, including prices for electricity, natural gas, coal and energy transmission. FirstEnergy's Risk Management Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 7, Fair Value Measurements, of the Combined Notes to Consolidated Financial Statements). Sources of information for the valuation of derivative contracts assets and liabilities as of March 31, 2014 are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	2014	2015	2016	2017	2018	Thereafter	Total
				(In millions)			
Prices actively quoted[1]	$ 3	$ —	$ —	$ —	$ —	$ —	$ 3
Other external sources[2]	16	(33)	(24)	(15)	—	—	(56)
Prices based on models	9	—	1	1	(13)	(14)	(16)
Total[3]	$ 28	$ (33)	$ (23)	$ (14)	$ (13)	$ (14)	$ (69)

(1) Represents exchange traded New York Mercantile Exchange futures and options.

(2) Primarily represents contracts based on broker and ICE quotes.

(3) Includes $185 million in non-hedge derivative contracts primarily related to NUG contracts. NUG contracts are generally subject to regulatory accounting and do not materially impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of March 31, 2014, a 10% adverse change in commodity prices would decrease net income by approximately $40 million during the next 12 months.

Equity Price Risk

As of March 31, 2014, the FirstEnergy pension plan assets were approximately allocated as follows: 33% in equity securities, 38% in fixed income securities, 20% in absolute return strategies, 6% in real estate and 3% in cash and short-term securities. A decline in the value of pension plan assets could result in additional funding requirements. FirstEnergy’s funding policy is based on actuarial computations using the projected unit credit method. During the three months ended March 31, 2014, FirstEnergy made no contributions to its qualified pension plans. See Note 3, Pensions and Other Postemployment Benefits, of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. Through March 31, 2014, FirstEnergy's pension plan assets earned approximately 2.9% as compared to an annual expected return on plan assets of 7.75%.

NDT funds have been established to satisfy NG’s and other FirstEnergy subsidiaries' nuclear decommissioning obligations. As of March 31, 2014, approximately 66% of the funds were invested in fixed income securities, 21% of the funds were invested in equity securities and 13% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $1,487 million, $463 million and $305 million for fixed income securities, equity securities and short-term investments, respectively, as of March 31, 2014, excluding $8 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $46 million reduction in fair value as of March 31, 2014. Certain FirstEnergy subsidiaries recognize in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FirstEnergy’s NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During the three months ended March 31, 2014, no contributions were made to the NDT.

Interest Rate Risk

FirstEnergy recognizes net actuarial gains or losses for its pension and OPEB plans in the fourth quarter of each fiscal year. A primary factor contributing to these actuarial gains and losses are changes in the discount rates used to value pension and OPEB obligations as of the measurement date of December 31 and the difference between expected and actual returns on the plans' assets. At this time FirstEnergy is unable to determine or project the mark-to-market adjustment that may be recorded as of December 31, 2014.

CREDIT RISK

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. FirstEnergy evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. FirstEnergy may impose specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. FirstEnergy monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

Wholesale Credit Risk

FirstEnergy measures wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to, or due from, counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FirstEnergy has a legally enforceable right of set-off. FirstEnergy monitors and manages the credit risk of wholesale marketing, risk management and energy transacting operations through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral and the use of master netting agreements. FirstEnergy's portfolio of energy contracts has a current weighted average risk rating of A (S&P) for energy contract counterparties.

Retail Credit Risk

FirstEnergy's principal retail credit risk exposure relates to its competitive electricity activities, which serve residential, commercial and industrial companies. Retail credit risk results when customers default on contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers.

Retail credit risk is managed through established credit approval policies, monitoring customer exposures and the use of credit mitigation measures such as deposits in the form of LOCs, cash or prepayment arrangements.

Retail credit quality is affected by the economy and the ability of customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, FirstEnergy's retail credit risk may be adversely impacted.

OUTLOOK

STATE REGULATION

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES and AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES, AE Supply and their public utility affiliates. In addition, if any of the FirstEnergy affiliates were to engage in the construction of significant new transmission or generation facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission or generation facility.

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to residential SOS for PE customers expired on December 31, 2012, by statute, service continues in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential SOS have also expired; however, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change. PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. PE's initial plan submitted in compliance with the statute was approved in 2009 and covered 2009-2011, the first three years of the statutory period. Expenditures were originally estimated to be approximately $101 million for the PE programs for the entire period of 2009-2015. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan for the second three year period, 2012-2014, that includes additional and improved programs. The 2012-2014 plan is expected to cost approximately $66 million out of the original $101 million estimate for the entire EmPOWER program. On December 22, 2011, the MDPSC issued an order approving PE's second plan with various modifications and follow-up assignments. PE continues to recover program costs subject

to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date such recovery has not been sought or obtained by PE.

Pursuant to a bill passed by the Maryland legislature in 2011, the MDPSC adopted rules, effective May 28, 2012, that create specific requirements related to a utility's obligation to address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. The MDPSC will be required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. The new rules set utility-specific SAIDI and SAIFI targets for 2012-2015; prescribe detailed tree-trimming requirements, outage restoration and downed wire response deadlines; and impose other reliability and customer satisfaction requirements. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately $106 million over the period 2012-2015. On April 1, 2013, the Maryland electric utilities, including PE, filed their first annual reports on compliance with the new rules. The MDPSC conducted a hearing on August 20, 2013 to discuss the reports, after which an order was issued on September 3, 2013, which accepted PE's filing and the operational changes proposed therein. PE filed its second annual report on March 27, 2014.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards which had become final on May 28, 2012; selective increased investment in system hardening; creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the utilities to submit several reports over a series of months, relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further requires the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE has responded to the requirements in the order consistent with the schedule set forth therein. PE's final filing on September 3, 2013, discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would expect to make approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. The MDPSC has ordered that certain reports of its Staff relating to these matters be provided by July 1, 2014, and otherwise has not issued a schedule for further proceedings in this matter.

NEW JERSEY

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On September 7, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. In its written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012. In the filing, JCP&L requested approval to increase its revenues by approximately $31.5 million and reserved the right to update the filing to include costs associated with the impact of Hurricane Sandy. The NJBPU transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ has been assigned. On February 22, 2013, JCP&L updated its filing to request recovery of $603 million of distribution-related Hurricane Sandy restoration costs, resulting in increasing the total revenues requested to approximately $112 million. On June 14, 2013, JCP&L further updated its filing to: 1) include the impact of a depreciation study which had been directed by the NJBPU; 2) remove costs associated with 2012 major storms, consistent with the NJBPU orders establishing a generic proceeding to review 2011 and 2012 major storm costs (discussed below); and 3) reflect other revisions to JCP&L's filing. That filing represented an increase of approximately $20.6 million over the revenues produced by existing base rates. Testimony has also been filed in the matter by the Division of Rate Counsel and several other intervening parties in opposition to the base rate increase JCP&L requested. Specifically, the testimony of the Division of Rate Counsel's witnesses recommended that revenues produced by JCP&L's base rates for electric service be reduced by approximately $202.8 million (such amount did not address the revenue requirements associated with major storm events of 2011 and 2012, which are subject to review in the generic proceeding). JCP&L filed rebuttal testimony in response to the testimony of other parties on August 7, 2013. Hearings in the rate case have concluded. In the initial briefs of the parties filed on January 27, 2014, the Division of Rate Counsel recommended that base rate revenues be reduced by $214.9 million while the

NJBPU Staff recommended a $207.4 million reduction (such amounts do not address the revenue requirements associated with the major storm events of 2011 and 2012). Reply briefs were filed on February 24, 2014. The matter is pending before the ALJ.

On March 20, 2013, the NJBPU ordered that a generic proceeding be established to investigate the prudence of costs incurred by all New Jersey utilities for service restoration efforts associated with the major storm events of 2011 and 2012. The Order provided that if any utility had already filed a proceeding for recovery of such storm costs, to the extent the amount of approved recovery had not yet been determined, the prudence of such costs would be reviewed in the generic proceeding. On May 31, 2013, the NJBPU clarified its earlier order to indicate that the 2011 major storm costs would be reviewed expeditiously in the generic proceeding with the goal of maintaining the base rate case schedule established by the ALJ where recovery of such costs would be addressed. The NJBPU further indicated in the May 31 clarification that it would review the 2012 major storm costs in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding. On June 21, 2013, consistent with NJBPU's orders, JCP&L filed the detailed report in support of recovery of major storm costs with the NJBPU. On February 24, 2014, a Stipulation was filed with the NJBPU by JCP&L, the Division of Rate Counsel and NJBPU Staff which will allow recovery of $736 million of JCP&L's $744 million of costs related to the significant weather events of 2011 and 2012. As a result, FirstEnergy recorded a regulatory asset impairment charge of approximately $8 million (pre-tax) as of December 31, 2013. By its Order of March 19, 2014, the NJBPU approved the Stipulation of Settlement and on March 25, 2014, transmitted a copy of that Order to the Office of Administrative Law so that “actual recovery of the 2011 costs can be determined in relation to the pending base rate case.” Recovery of 2011 storm costs will be addressed in the pending base rate case; recovery of 2012 storm costs will be determined by the NJBPU.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held in September 2011 to solicit comments regarding the state of preparedness and responsiveness of New Jersey's EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 28, 2011 related to this inquiry. On December 14, 2011, the NJBPU Staff filed a report of its preliminary findings and recommendations with respect to the electric utility companies' planning and response to Hurricane Irene and the October 2011 snowstorm. The NJBPU selected a consultant to further review and evaluate the New Jersey EDCs' preparation and restoration efforts with respect to Hurricane Irene and the October 2011 snowstorm, and the consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. JCP&L submitted written comments on the report. On January 24, 2013, based upon recommendations in its consultant's report, the NJBPU ordered the New Jersey EDCs to take a number of specific actions to improve their preparedness and responses to major storms. The order includes specific deadlines for implementation of measures with respect to preparedness efforts, communications, restoration and response, post event and underlying infrastructure issues. On May 31, 2013, the NJBPU ordered that the New Jersey EDCs implement a series of new communications enhancements intended to develop more effective communications among EDCs, municipal officials, customers and the NJBPU during extreme weather events and other expected periods of extended service interruptions. The new requirements include making information regarding estimated times of restoration available on the EDC's web sites and through other technological expedients. JCP&L is implementing the required measures consistent with the schedule set out in the above NJBPU's orders.

OHIO

The Ohio Companies primarily operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include:

- Generation supplied through a CBP;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, which also applies to tranches assigned post-auction;
- A 6% generation discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- No increase in base distribution rates through May 31, 2014; and
- A new distribution rider, Rider DCR, to recover a return of, and on, capital investments in the delivery system.

The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI's integration into PJM for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain PJM proceedings. The Ohio Companies also agreed to establish a $12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012. Several parties timely filed applications for rehearing. The PUCO issued an Entry on Rehearing on January 30, 2013 denying all applications for rehearing. Notices of appeal to the Supreme Court of Ohio were filed by two parties in the case, Northeast Ohio Public Energy Council and the ELPC. While briefing has been completed, the matter has not yet been scheduled for oral argument.

As approved, the ESP 3 plan continues certain provisions from the current ESP including:

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the existing ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan provides additional provisions, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Under SB221, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. The Ohio Companies were also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018. On May 15, 2013, the Ohio Companies filed their 2012 Status Update Report in which they indicated compliance with 2012 statutory energy efficiency and peak demand reduction benchmarks.

In accordance with PUCO Rules and a PUCO directive, on July 31, 2012 the Ohio Companies filed their three-year portfolio plan for the period January 1, 2013 through December 31, 2015. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period, which is expected to be recovered in rates to the extent approved by the PUCO. Hearings were held with the PUCO in October 2012. On March 20, 2013, the PUCO approved the three-year portfolio plan for 2013-2015. Applications for rehearing were filed by the Ohio Companies and several other parties on April 19, 2013. The Ohio Companies filed their request for rehearing primarily to challenge the PUCO's decision to mandate that they offer planned energy efficiency resources into PJM's base residual auction. On May 15, 2013, the PUCO granted the applications for rehearing for the sole purpose of further consideration of the matter. On July 17, 2013, the PUCO denied the Ohio Companies' application for rehearing, in part, but authorized the Ohio Companies to receive 20% of any revenues obtained from bidding energy efficiency and demand response reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. On August 16, 2013, ELPC and OCC filed applications for rehearing under the basis that the PUCO's authorization for the Ohio Companies to share in the PJM revenues was unlawful. The PUCO granted rehearing on September 11, 2013 for the sole purpose of further consideration of the issue.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with and are not supported by statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal. The Ohio Companies' response was filed on November 4, 2013. The motion is still pending and additional briefing has followed. While briefing has been completed, the matter has not been scheduled for oral argument.

SB221 requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2024. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet the renewable energy requirements established under SB221. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs and selected auditors to perform a financial and management audit. Final audit reports filed with the PUCO generally supported the Ohio Companies' approach to procurement of RECs, but also recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of in-state renewable obligations that the auditor characterized as excessive. Following the hearing, the PUCO issued an Opinion and Order on August 7, 2013 approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for part of the purchases arising from one auction and directing the Ohio Companies to credit non-shopping customers in the amount of $43.3 million, plus interest, and to file tariff schedules reflecting the refund and interest costs within 60 days following the issuance of a final appealable order on the basis that the Ohio Companies did not prove such purchases were prudent. The Ohio Companies, along with other parties, timely filed applications for rehearing on September 6, 2013. On December 18, 2013, the PUCO denied all of the applications for rehearing. Based on the PUCO ruling a regulatory charge of approximately $51 million, including interest, was recorded in the fourth quarter of 2013. On December 24, 2013, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio. On February 10, 2014, the Supreme Court of Ohio granted the Ohio Companies' motion for stay, which went into effect on February 14, 2014. On February 18, 2014, the Office of Consumers' Counsel and the ELPC also filed appeals of the PUCO's order. The Ohio Companies filed their merit brief with the Supreme Court of Ohio on March 6, 2014. On April 15, 2014, the Supreme Court of Ohio stayed the briefing schedule pending the court's resolution of the Ohio Companies' motion to seal certain confidential portions of the appendix and supplement to their merit brief.

The Ohio Companies conducted an RFP in 2013 to cover their all-state SREC and their in-state and all-state REC compliance obligations. On April 15, 2014, the Ohio Companies reported that they met all of their annual renewable energy resource requirements for reporting year 2013.

The PUCO instituted a statewide investigation on December 12, 2012 to evaluate the vitality of the competitive retail electric service market in Ohio. The PUCO provided interested stakeholders the opportunity to comment on twenty-two questions. The questions posed are categorized as market design and corporate separation. The Ohio Companies timely filed their comments on March 1, 2013, and filed reply comments on April 5, 2013. On June 5, 2013, the PUCO requested additional comments and reply comments on the topics of market design and corporate separation, which the Ohio Companies timely filed on July 8, 2013 and July 22, 2013, respectively. The PUCO held a series of workshops throughout 2013, which included an en banc workshop on December 11, 2013. The PUCO Staff filed a report on January 16, 2014, which contained a limited discussion of the workshops and the PUCO Staff's recommendations. The Ohio Companies submitted comments on February 6, 2014 and Reply Comments on February 20, 2014. The PUCO issued its Order in this matter on March 26, 2014, which included a wide range of issues such as, maintaining SSO service in its current form, requiring corporate separation audits of all EDUs, establishing a market development working group, and ordering changes to the bill format. The Ohio Companies filed their Application for Rehearing on April 25, 2014. The Ohio Companies filed their memorandum contra applications for rehearing of other stakeholders on May 5, 2014.

On April 9, 2014, the PUCO initiated a generic investigation of marketing practices in the competitive retail electric service market, with a focus on the marketing of fixed-price or guaranteed percent-off SSO rate contracts where there is a provision that permits the pass-through of new or additional charges.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2015, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through descending clock auctions, competitive requests for proposals and spot market purchases. On November 4, 2013, the Pennsylvania Companies filed a DSP that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2015 through May 31, 2017. The Pennsylvania Companies proposed programs call for quarterly descending clock auctions to procure 3, 12, 24, and 48-month energy contracts, as well as, one RFP seeking 2-year contracts to secure SRECs for ME, PN, and Penn. The Pennsylvania Companies have reached a settlement with all parties on all issues raised in the case with the exception of the treatment of NITS charges. On May 6, 2014, the ALJ issued a Recommended Decision recommending adoption of the settlement without modification and the denial of several parties' request for non-bypassable treatment of NITS charges. A final order is expected from the PPUC by August 2014.

The PPUC entered an Order on March 3, 2010 that denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed ME and PN to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC. Pursuant to a plan approved by the PPUC, ME and PN refunded those amounts to customers over a 29-month period that began in January of 2011. On appeal, the Commonwealth Court affirmed the PPUC's Order to the extent that it holds that line loss costs are not transmission costs and, therefore, the approximately $254 million in marginal transmission losses and associated carrying charges for the period prior to January 1, 2011, are not recoverable under ME's and PN's TSC riders. The Pennsylvania Supreme Court denied ME's and PN's Petition for Allowance of Appeal and the Supreme Court of the United States denied ME's and PN's Petition for Writ of Certiorari. ME and PN also filed a complaint in the U.S. District Court for the Eastern District of Pennsylvania to obtain an order that would enjoin enforcement of the PPUC and Pennsylvania court orders under a theory of federal preemption on the question of retail rate recovery of the marginal transmission loss charges. On September 30, 2013, the U.S. District Court granted the PPUC's motion to dismiss. As a result of the U.S. District Court's decision, FirstEnergy recorded a regulatory asset impairment charge of approximately $254 million (pre-tax) in the quarter ended September 30, 2013. The balance of marginal transmission losses was fully refunded to customers by the second quarter of 2013. On October 29, 2013, ME and PN filed a Notice of Appeal of the U.S. District Court's decision to dismiss the complaint with the United States Court of Appeals for the Third Circuit. Oral argument was held on April 8, 2014, and, at the end of the argument, the Third Circuit directed ME and PN, and the PPUC, each to submit a brief on April 16, 2014 on the question of whether it is possible to waive the preemptive effect of FERC's classification of line loss charges as transmission charges. On April 16, 2014, ME and PN, the PPUC, and the Pennsylvania Industrials each submitted briefs on the Third Circuit's questions.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan (EE&C Plan) by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 provides for potentially significant financial penalties to be assessed on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted a report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. ME, PN and Penn achieved the 2011 benchmarks; however WP did not. WP could be subject to a statutory penalty of between $1 and $20 million. On November 15, 2013, the Pennsylvania Companies submitted their energy efficiency and peak demand reduction report for the period ending May 31, 2013, in which they indicated that all of the Pennsylvania Companies met their statutory

requirements. On March 20, 2014, the PPUC issued an Order initially determining that ME, PN and Penn achieved the 2011 and 2013 statutory energy efficiency benchmarks. The PPUC also initially determined that WP is not in compliance with the 2011 statutory energy efficiency benchmarks but is in compliance with the 2013 energy efficiency benchmarks. As such, the PPUC, with regards to WP's compliance with the 2011 statutory benchmarks, referred the matter to the PPUC Bureau of Investigation and Enforcement for the initiation of an appropriate proceeding no later than May 30, 2014 to investigate whether WP is in compliance with the 2011 statutory benchmarks and whether WP is subject to statutory penalties. The PPUC also ordered that the initial determination will be deemed final unless any petitions challenging its initial determination are filed within 20 days of the Order. On April 9, 2014, WP filed its petition challenging the PPUC's initial determination arguing, among other things, that the May 2011 target was not mandatory and WP is in compliance because it achieved its May 2013 targets. On April 21, 2014, WP filed an appeal with the Commonwealth Court of Pennsylvania in which it challenged the PPUC's initial finding of a violation of Act 129 on due process grounds. On that same day, the Bureau of Investigation and Enforcement, consistent with the PPUC's March 20, 2014 Order, initiated a proceeding by filing a Complaint against WP in which it alleges that WP violated Act 129 and recommends a penalty in the amount of $11.4 million. The Pennsylvania Companies have 20 days in which to respond to the Complaint. A prehearing conference is scheduled for May 9, 2014 at which time a procedural schedule for this matter is expected to be established.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 15, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator. Based upon information received, the PPUC has not included a peak demand reduction requirement in the Phase II plans. The Pennsylvania Companies filed their Phase II plans and supporting testimony in November 2012. On January 16, 2013, the Pennsylvania Companies reached a settlement with all but one party on all but one issue. The settlement provides for the Pennsylvania Companies to meet with interested parties to discuss ways to expand upon the EE&C programs and incorporate any such enhancements after the plans are approved, provided that these enhancements will not jeopardize the Pennsylvania Companies' compliance with their required targets or exceed the statutory spending caps. On February 6, 2013, the Pennsylvania Companies filed revised Phase II EE&C Plans to conform the plans to the terms of the settlement. Total costs of these plans are expected to be approximately $234 million. All such costs are expected to be recoverable through the Pennsylvania Companies reconcilable Phase II EE&C Plan C riders. The remaining issue, raised by a natural gas company, involved the recommendation that the Pennsylvania Companies include in their plans incentives for natural gas space and water heating appliances. On March 14, 2013, the PPUC approved the 2013-2016 EE&C plans of the Pennsylvania Companies, adopting the settlement, and rejecting the natural gas companies recommendations.

In addition, Act 129 required utilities to file a SMIP with the PPUC. On December 31, 2012, the Pennsylvania Companies filed their Smart Meter Deployment Plan. The Deployment Plan requested deployment of approximately 98.5% of the smart meters to be installed over the period 2013 to 2019, and the remaining meters in difficult to reach locations to be installed by 2022, with an estimated life cycle cost of about $1.25 billion. Such costs are expected to be recovered through the Pennsylvania Companies' PPUC-approved Riders SMT-C. Evidentiary hearings were held and briefs were submitted by the Pennsylvania Companies and the OCA. On November 8, 2013, the ALJ issued a Recommended Decision recommending that the Pennsylvania Companies' Deployment Plan be adopted with certain modifications, including, among other things, that the Pennsylvania Companies perform further benchmarking analyses on their costs and hire an independent consultant to perform further analyses on potential savings. On December 2, 2013, the Pennsylvania Companies submitted exceptions in which they challenged, among other things, certain recommendations in the ALJ's decision, and requested approval of a modification to the deployment schedule so as to allow the entire Penn smart meter system (170,000 meters) to be built by the end of 2015, instead of the original proposed installation of 60,000 meters by the end of 2016. The OCA took exception to one issue and both parties filed replies to exceptions on December 12, 2013. In its March 6, 2014 Opinion and Order, the PPUC rejected the OCA's exception and many of the ALJ's recommendations, including the recommendation to hire an independent consultant and the disallowance of $5.1 million of customer information system costs, and affirmed the ALJ's recommendation on the accounting treatment for legacy meter costs. The PPUC also directed the Pennsylvania Companies to file an amendment to the Deployment Plan within thirty days of the Order with sufficient supporting documentation for proper evaluation if the Pennsylvania Companies intend to pursue an accelerated deployment schedule, and the PPUC indicated that it would establish an expedited procedural schedule and rule on the filing within 90 days of the March 6, 2014 Order. The Pennsylvania Companies filed an amended Deployment Plan on March 19, 2014, to which, the OCA filed exceptions arguing that the amended plan failed to: 1) list certain potential cost savings categories that are to be considered by the Pennsylvania Companies; and 2) follow proper procedure. On April 7, 2014, the Pennsylvania Companies filed a reply to OCA's exceptions explaining why they should be rejected. A prehearing conference was held on April 25, 2014, and a procedural schedule was established that is expected to allow the PPUC to issue an order by June 5, 2014.

In the PPUC Order approving the FirstEnergy and AE merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions concerning retail markets in Pennsylvania to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A final order was issued on February 15, 2013, providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items. Subsequently,

the PPUC established five workgroups and one comment proceeding in order to seek resolution of certain matters and to clarify certain obligations that arose from that order.

The PPUC issued a Proposed Rulemaking Order on August 25, 2011, which proposed a number of substantial modifications to the current Code of Conduct regulations that were promulgated to provide competitive safeguards to the competitive retail electricity market in Pennsylvania. The proposed changes include, but are not limited to: an EGS may not have the same or substantially similar name as the EDC or its corporate parent; EDCs and EGSs would not be permitted to share office space and would need to occupy different buildings; EDCs and affiliated EGSs could not share employees or services, except certain corporate support, emergency, or tariff services (the definition of "corporate support services" excludes items such as information systems, electronic data interchange, strategic management and planning, regulatory services, legal services, or commodities that have been included in regulated rates at less than market value); and an EGS must enter into a trademark agreement with the EDC before using its trademark or service mark. The Proposed Rulemaking Order was published on February 11, 2012, and comments were filed by the Pennsylvania Companies and FES on March 27, 2012. If implemented these rules could require a significant change in the ways FES and the Pennsylvania Companies do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition. Pennsylvania's Independent Regulatory Review Commission subsequently issued comments on the proposed rulemaking on April 26, 2012, which called for the PPUC to further justify the need for the proposed revisions by citing a lack of evidence demonstrating a need for them. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified. On March 24, 2014, the PPUC issued a letter withdrawing the Proposed Rulemaking.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement reached with the other parties and approved by the WVPSC in June 2010 that provided for:

- $40 million annualized base rate increases effective June 29, 2010;
- Deferral of February 2010 storm restoration expenses over a maximum five-year period;
- Additional $20 million annualized base rate increase effective in January 2011;
- Decrease of $20 million in ENEC rates effective January 2011, providing for deferral of related costs for later recovery in 2012; and
- Moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012 and two public input hearings have been held. The WVPSC issued an Order in this matter on January 23, 2013 closing the proceeding and directing electric utilities to file a vegetation management plan within six months and to propose a cost recovery mechanism. This Order also requires MP and PE to file a status report regarding improvements to their storm response procedures by the same date. On July 23, 2013, MP and PE filed their vegetation management plans, which provided for recovery of costs through a surcharge mechanism. A hearing was held on December 3, 2013, and briefing followed. The WVPSC issued an order on April 14, 2014 approving the plan, stating rate recovery will be addressed in the base rate case filed on April 30, 2014. In the interim, MP and PE are authorized to defer all costs associated with the plan.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE filed a Petition for approval of a Generation Resource Transaction with the WVPSC in November 2012 that proposed a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer involved MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. FERC authorized the transfers on April 23, 2013 and the financing on May 13, 2013. A Joint Settlement Agreement was filed by the majority of parties on August 21, 2013. On October 7, 2013, the WVPSC authorized the transaction, with certain conditions, and on October 9, 2013, the transaction closed resulting in MP recording a pre-tax impairment charge of approximately $322 million in the fourth quarter of 2013 to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. Concurrently, MP recognized a regulatory liability of approximately $23 million representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. The $1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately $527 million and a note payable to AE Supply of approximately $573 million. The note payable to AE Supply was paid in the fourth quarter of 2013. The settlement also required MP and PE to file a base rate case by April 30, 2014. On November 6, 2013, the WVCAG petitioned for appeal with the Supreme Court of Appeals of West Virginia. MP and PE filed their response to the WVCAG petition on December 27, 2013 and WVCAG filed its reply on January 16, 2014. The Supreme Court of Appeals of West Virginia held oral arguments on March 5, 2014. On April 23, 2014 the Supreme Court of Appeals of West Virginia delivered an Opinion affirming the WVPSC order approving the Generation Resource Transaction.

On April 30, 2014, MP and PE filed a rate case requesting a base rate increase of approximately $96 million, or 9.3%. The filing also included a surcharge to recover costs of MP's and PE's vegetation management program in the amount of approximately $48

million. The proposed total rate increase request, including the cost of the vegetation management program, is approximately $144 million, or 14%. MP and PE anticipate a decision from the WVPSC in February 2015.

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, ATSI and TrAIL. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases “self-reporting” an item to RFC. Moreover, it is clear that the NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk power system could result in the imposition of financial penalties that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis - each customer in the zone would pay based on its total usage of energy within PJM. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit found that FERC had not supported a prior FERC decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on that finding, remanded the rate design issue to FERC. In an order dated January 21, 2010, FERC set this matter for a “paper hearing” and requested parties to submit written comments. FERC identified nine separate issues for comment and directed PJM to file the first round of comments. PJM filed certain studies with FERC on April 13, 2010, which demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain LSEs in PJM bearing the majority of the costs. FirstEnergy and a number of other utilities, industrial customers and state utility commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state utility commissions supported continued socialization of these costs on a load ratio share basis. On March 30, 2012, FERC issued an order on remand reaffirming its prior decision that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp (or socialized) rate based on the amount of load served in a transmission zone and concluding that such methodology is just and reasonable and not unduly discriminatory or preferential. On April 30, 2012, FirstEnergy requested rehearing of FERC's March 30, 2012 order and on March 22, 2013, FERC denied rehearing. On March 29, 2013, FirstEnergy filed a Petition for Review with the U.S. Court of Appeals for the Seventh Circuit, and the case subsequently was consolidated with several other cases before that court for briefing and disposition. Briefing is complete, oral argument was held on April 22, 2014, and a decision is expected in 2014.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the effective date of the compliance filing. On January 31, 2013, FERC conditionally accepted the hybrid method to be effective on February 1, 2013, subject to refund and to a future order on PJM's separate Order No. 1000 compliance filing. On March 22, 2013, FERC again accepted the hybrid method. Certain parties sought rehearing of parts of FERC's March 22, 2013 order. These requests for rehearing are pending before FERC. On July 10, 2013, the PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between: (1) the PJM region and the NYISO region and; (2) the PJM region and the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the cost of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region. On the same date, also in response to Order No. 1000, the PJM transmission owners, including FirstEnergy, also submitted to FERC a filing stating that the cost allocation provisions for interregional transmission projects provided in the Joint Operating Agreement between PJM and MISO comply with the requirements of Order No. 1000. On December 30, 2013, FERC conditionally accepted the PJM/SERTP cross-border project cost allocation filing, subject to refund and future orders in PJM's and SERTP's related Order No. 1000 interregional compliance proceedings. The PJM/NYISO and PJM/MISO cross-border project cost allocation filings remain pending before FERC. On January 16, 2014, FERC issued an order regarding the effective date of PJM's

separate Order No. 1000 regional transmission planning and cost allocation compliance filing, noting that it would address the merits of the comments on and protests to that filing and related compliance filings in a future order.

Numerous parties, including ATSI, FES, TrAIL, OE, CEI, TE, Penn, JCP&L, ME, MP, PN, WP and PE, sought judicial review of Order No. 1000 before the U.S. Court of Appeals for the D.C. Circuit. Briefing is complete and oral argument was held on March 20, 2014.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone. While many of the matters involved with the move have been resolved, FERC denied recovery by means of ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis that demonstrates net benefits to customers from the move. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC to resolve the exit fee and transmission cost allocation issues. However, FERC subsequently rejected that settlement, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. On October 21, 2013, FirstEnergy filed a request for rehearing of FERC's order.

Separately, the question of ATSI's responsibility for certain costs for the “Michigan Thumb” transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings in front of FERC and certain U.S. appellate courts. The MISO and its allied parties assert that the benefits to the ATSI zone of the Michigan Thumb project are roughly commensurate with the costs that MISO desires to charge to the ATSI zone, estimated to be as much as $16 million per year. ATSI has submitted evidence that the Michigan Thumb project provides no electric benefits to the ATSI zone and, on that basis, opposes the MISO’s efforts to impose these costs on the ATSI zone loads. The MISO and its allied parties also assert that certain language in the MISO Transmission Owners Agreement requires ATSI to pay these charges. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. While FERC proceedings regarding whether the MISO can charge ATSI for MVP costs remain pending, on February 24, 2014, the U.S. Supreme Court declined to hear appeals filed by FirstEnergy and other parties of the Seventh Circuit's June 2013 decision upholding FERC's acceptance of the MISO's generic MVP cost allocation proposal.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to transmission customers in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. ATSI subsequently filed a petition for review with the U.S. Court of Appeals for the D.C. Circuit. Briefing is complete, oral argument was held on December 11, 2013, and a decision is expected in the second quarter of 2014.

The outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM cannot be predicted at this time.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the U.S. Court of Appeals for the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets, during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011, and affirmed the dismissal in June 2012. On June 20, 2012, the California Parties appealed FERC's decision back to the Ninth Circuit. Briefing was completed before the Ninth Circuit on October 23, 2013. The timing of further action by the Ninth Circuit is unknown.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed another complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General has appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

The PATH project was proposed to be comprised of a 765 kV transmission line from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland. PJM initially authorized construction of the PATH project in June 2007. On August 24, 2012, the PJM Board of Managers canceled the PATH project, which it had suspended in February 2011. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed return on equity of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% return on equity adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement judge procedures and hearing if the parties do not agree to a settlement. PATH, PATH-Allegheny and PATH-WV have requested rehearing of FERC's denial of the 0.5% return on equity adder for RTO membership; that request for rehearing remains pending before FERC. In addition, FERC consolidated for settlement judge procedures and hearing purposes three formal challenges to the PATH formula rate annual updates submitted to FERC in June 2010, June 2011 and June 2012, with the September 28, 2012 filing for recovery of costs associated with the cancellation of the PATH project.

On March 20, 2014, the settlement judge declared an impasse in efforts to achieve settlement. On March 24, 2014, the Chief ALJ terminated settlement judge procedures and appointed an ALJ to preside over the hearing phase of the case. The hearing is scheduled to commence on November 5, 2014. The issues set for hearing include the prudence of the costs, the base return on equity and the period of recovery. Depending on the outcome of the hearing, PATH-Allegheny and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

Hydroelectric Asset Sale

On September 4, 2013, certain of FirstEnergy's subsidiaries submitted filings with FERC for authorization to sell eleven hydroelectric power plant projects to subsidiaries of Harbor Hydro Holdings, LLC (Harbor Hydro), a subsidiary of LS Power Equity Partners II, LP (LS Power). The eleven hydroelectric projects are: the Seneca Pumped Storage Project, Allegheny Lock & Dam No. 5, Allegheny Lock & Dam No. 6, the Lake Lynn Project, the Millville Hydro Project, the Dam No. 4 Project, the Dam No. 5 Project, and four additional projects located in Shenandoah, Front Royal and Luray, Virginia. The eleven projects have a combined generating capacity of approximately 527 MW. On February 12, 2014, the sale of the hydroelectric power plants to LS Power closed for approximately $394 million. See Note 13, Discontinued Operations for additional information regarding the assets sold.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties have submitted filings arguing that MISO's concerns largely are without foundation and suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. On April 2, 2013, FERC issued an order directing MISO and PJM to make presentations to FERC regarding ongoing regional efforts to address whether barriers to transfer capability exist between the MISO and PJM regions and the actions the FERC should take to address any such barriers. The RTOs presented their respective positions to FERC on June 20, 2013 and provided additional information regarding their stakeholder prioritization survey, in response to a FERC request on June 27, 2013. On September 26, 2013, the RTOs jointly submitted an informational filing providing a description of and schedule for their Joint and Common Market initiatives. On December 19, 2013, FERC issued an order directing that FERC staff are to attend the "joint and common market" stakeholder meetings for the purpose of monitoring progress on the initiatives described in the September 26, 2013 joint informational filing and establishing a new proceeding to reflect the broadened scope of issues contemplated by that filing and the RTOs' joint and common market initiatives. FERC has not acted on the presentations, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

MOPR Reform

On December 7, 2012, PJM filed amendments to its tariff to revise the MOPR used in the RPM. PJM revised the MOPR to add two broad, categorical exemptions, eliminate an existing exemption, and to limit the applicability of the MOPR to certain capacity resources. The filing also included related and conforming changes to the RPM posting requirements and to those provisions describing the role of the Independent Market Monitor for the PJM Region. On May 2, 2013, FERC issued an order in large part accepting PJM's proposed reform of the MOPR, including the proposed exemptions and applicability but also requiring PJM to commit to future review and, if necessary, additional revisions to the MOPR to accommodate changing market conditions. On June 3, 2013, FirstEnergy submitted a request for rehearing of FERC's May 2, 2013 order. In its rehearing request, FirstEnergy referenced the results of the May 2013 PJM RPM capacity auction, and publicly-available data about the reasons for the unexpectedly low "rest-of-RTO" clearing price of $59 per MW-day, as supporting its contention that the MOPR reform depressed prices as predicted in FirstEnergy's December 28, 2012 and January 25, 2013 comments. FirstEnergy's request for rehearing is pending before FERC.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and they operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM tariff, the funds that are set aside to pay FTRs can be diverted to other uses, resulting in "underfunding" of FTR payments. Since June 2010, FES and AE Supply have lost more than $87 million in revenues that they otherwise would have received as FTR holders to hedge congestion costs. FES and AE Supply expect to continue to experience significant underfunding.

On December 28, 2011, FES and AE Supply filed a complaint with FERC for the purpose of modifying certain provisions in the PJM tariff to eliminate FTR underfunding. On March 2, 2012, FERC issued an order dismissing the complaint. In its order, FERC ruled that it was not appropriate to initiate action at that time because of the unknown root causes of FTR underfunding. FERC directed PJM to convene stakeholder proceedings for the purpose of determining the root causes of the FTR underfunding. FERC went on to note that its dismissal of the complaint was without prejudice to FES and AE Supply or any other affected entity filing a complaint if the stakeholder proceedings proved unavailing. FES and AE Supply sought rehearing of FERC's order and, on July 19, 2012, FERC denied rehearing. In April 2012, PJM issued a report on FTR underfunding. However, the PJM stakeholder process proved unavailing as the stakeholders were not willing to change the tariff to eliminate FTR underfunding. Accordingly, on February 15, 2013, FES and AE Supply re-filed their complaint with FERC for the purpose of changing the PJM tariff to eliminate FTR underfunding. Various parties filed responsive pleadings, including PJM. On June 5, 2013, FERC issued its order denying the new complaint. On July 5, 2013,FESC, on behalf of FES and AE Supply, filed a request for rehearing of FERC's order. That request for rehearing, and all subsequent filings in the docket, are pending before FERC.

PJM RPM Tariff Amendments

In November 2013, PJM began to submit a series of amendments to its RPM capacity tariff in order to address certain problems that have been observed in recent auctions. These problems can be grouped into four categories: (i) Demand Response (DR); (ii) imports; (iii) modeling of transmission upgrades in calculating geographic clearing prices; and (iv) arbitrage/capacity replacement. The purpose of PJM's tariff amendments is to ensure that resources that clear in the RPM auctions are available as physical resources in the delivery year and that the rules implement comparable obligations for different types of resources. In each of the relevant dockets, FirstEnergy submitted comments as part of a coalition of utilities (generally including an affiliate of AEP, Duke and Dayton). The FirstEnergy/coalition position was that all of the PJM proposals should be accepted as proposed, and that the FERC should order PJM to take additional steps that should have the effect of eliminating additional distortions and flaws in the RPM market. PJM made two filings regarding DR; FERC accepted one as proposed on January 30, 2014, and issued a deficiency letter regarding the other on March 6, 2014. FERC also issued deficiency letters requesting additional information from PJM regarding the modeling filing on January 17, 2014 and regarding the imports filing on January 28, 2014. On February 18 and 21, 2014, respectively, PJM filed its responses to FERC's deficiency letters regarding the modeling filing and the imports filing. On April 18, 2014, FERC conditionally accepted PJM's modeling filing, as supplemented, subject to PJM's submission of a compliance filing. On April 22, 2014, FERC accepted PJM's imports filing, as supplemented. The second DR filing, which relates to the rules applicable to DR performance obligations, the arbitrage/capacity replacement filing and related filings in those dockets, and a request for rehearing of the January 30, 2014 order on the first DR filing, are pending before FERC. PJM requested FERC action on the DR performance obligations filing by April 11, 2014, and prior to the May 2014 BRA for the arbitrage/capacity replacement filing. Although FirstEnergy believes that these filings (and the associated tariff changes) should have positive implications for RPM clearing prices, generally there can be no assurance as to their ultimate impact on FirstEnergy.

PJM RPM Auctions - Calculation of Unit-Specific Offer Caps

The PJM RPM capacity tariff describes the rules for calculating the "offer cap" for each unit that offers into the RPM auctions. In summary, the offer cap is calculated by identifying certain going-forward costs, including the going-forward capital requirements, for a given unit, and then subtracting the projected energy and ancillary services revenues, net of marginal costs, from the going-forward costs. The remainder becomes the offer cap. FES learned that the PJM Market Monitor's practice for calculating the forecast energy and ancillary services revenues has been to use the lower of the unit's economic or cost-based offers into the PJM energy market. The Market Monitor engages in this practice based on his interpretation of certain provisions of the PJM capacity tariff. However, review of the relevant tariff language suggests that only the cost-based offer data should be used. FES determined that the Market Monitor's use of the lower of cost-based or economic offer data has the effect of suppressing the offer cap, which can distort the price signal that is intended to come out of the RPM auction process. On April 7, 2014, FES submitted a Petition for Declaratory Order to FERC, asking for an interpretation of the relevant provisions of the PJM capacity tariff. Specifically, FES identified the difference of opinion between FES and the Market Monitor regarding interpretation of the relevant provision and asked FERC to rule on the question of whether the tariff language permits the Market Monitor's use of the lower of cost-based or economic offer data or requires use of the cost-based offer data. FES asked FERC to rule on the petition by May 9, 2014. On April 18, 2014, the Market Monitor and other parties filed protests to FES's petition, arguing that the PJM capacity tariff allows the Market Monitor to use market-based energy offers instead of cost-based energy offers in calculating RPM auction offer caps and asking FERC to delay action on the petition until after the May 2014 BRA. FES' petition, the protest, and related filings are pending before FERC. The timing of FERC action and the outcome of this proceeding cannot be predicted at this time.

Market-Based Rate Authority, Triennial Update

OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP, PE, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC's requirements for holding market-based rate authority. On December 20, 2013, FESC submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. That filing is pending before FERC.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

CAA Compliance

FirstEnergy is required to meet federally-approved SO_2 and NOx emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a "safe, responsible, prudent and proper manner." One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued an NOV to GenOn Energy, Inc. alleging NSR violations at the Keystone, Portland and Shawville coal-fired plants based on "modifications" dating back to the mid-1980s. JCP&L, as the former owner of 16.67% of the Keystone Station, ME, as a former owner and operator of the Portland Station, and PN as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations, at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. The EPA's NOV alleges equipment replacements during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically, opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. FG intends to comply with the CAA and Ohio regulations, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued additional CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply, MP, PE and WP in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that AE performed major modifications in violation of the NSR provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. A non-jury trial on liability only was held in September 2010. On February 6, 2014, the Court entered judgment for AE, AE Supply, MP, PE and WP finding they had not violated the CAA or the Pennsylvania Air Pollution Control Act. On March 10, 2014, New York, Connecticut, and Maryland filed an appeal with the U.S. Court of Appeals for the Third Circuit. This decision does not change the status of these plants which remain deactivated.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the D.C. Circuit decided that CAIR violated the CAA but allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaces CAIR with a new rule consistent with the Court's decision. In July 2011, the EPA finalized CSAPR, to replace CAIR, requiring reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit and was ultimately vacated by the Court on August 21, 2012. The Court has ordered the EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. On April 29, 2014 the U.S. Supreme Court reversed the D.C Circuit decision vacating CSAPR and generally upheld the EPA's authority under the CAA to establish the regulatory structure underpinning CSAPR. Depending on the outcome of further proceedings in this matter and how the EPA and the states implement the final rules, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants stations. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield stations. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. MATS was challenged in the U.S. Court of Appeals for the D.C. Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. On April 15, 2014, MATS was upheld by the U.S. Court of Appeals for the D.C. Circuit, however, the Court refused to decide FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers due to a January 2013 petition for reconsideration still pending but not addressed by EPA. Depending on the outcome of further appeals, if any, and how the MATS are ultimately implemented, FirstEnergy's total cost of compliance with MATS is currently estimated to be approximately $465 million (Competitive Energy Services segment of $240 million and Regulated Distribution segment of $225 million).

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island were deactivated. FG entered into RMR arrangements with PJM for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015, when they are scheduled to be deactivated. In February 2014, PJM notified FG that Eastlake Units 1-3 and Lake Shore Unit 18 will be released from RMR status as of September 15, 2014. As of October 9, 2013, the Hatfield's Ferry and Mitchell stations were also deactivated.

FirstEnergy and FES have various long-term coal transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. FE and FES have asserted force majeure defenses for delivery shortfalls under certain agreements, and are in discussion with the applicable counterparties. As to two agreements, FE and FES have settled monetary claims for damages for the failure to take minimum quantities for the calendar year 2012 by the payment of approximately $70 million, and agreed to pay liquidated damages for delivery shortfalls for 2013 and 2014. FE and FES recorded $67 million in liquidated damages in the fourth quarter of 2013, associated with estimated 2013 delivery shortfalls, which were paid in the first quarter of 2014. Additionally, in January 2014, FE and FES reached an agreement in principle with Mepco Holdings LLC to terminate a contract for future coal deliveries to Hatfield for $18 million, which was approved by the United States Bankruptcy Court on February 26, 2014. If FE and FES fail to reach a resolution with applicable counterparties for coal transportation agreements associated with the deactivated plants or unresolved aspects of the transportation agreements and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses do not excuse delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. If that were to occur, FE and FES are unable to estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies to reduce GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. In his 2013 State of the Union address, President Obama called for Congressional action on GHG emissions indicating his administration will take action in the event Congress fails to act. In June 2013, the President's Climate Action Plan outlined goals to: (1) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (2) prepare the United States for the impacts of climate change; and (3) lead international efforts to combat global climate change and prepare for its impacts. GHG emissions have already been reduced by 10% between 2005 and 2012 according to an April, 2014 EPA Report. Due to plant deactivations and increased efficiencies, FirstEnergy anticipates its CO2 emissions will be reduced 25% below 2005 levels by 2016, exceeding the President's Climate Action Plan goals both in terms of timing and reduction levels.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required the measurement and reporting of GHG emissions commencing in 2010. In December 2009, the EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act." The EPA's finding concludes that concentrations of several key GHGs increase the threat of climate change and may be regulated as "air pollutants" under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of CO_2 equivalents for existing facilities under the CAA's PSD program. On April 13, 2012, the EPA proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units that are larger than 25 MW, which were ultimately withdrawn. On June 25, 2013, a Presidential memorandum directed the EPA to complete, in a timely fashion, proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units, starting with re-proposal by September 20, 2013. The memorandum further directed the EPA to propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel generating units. On September 20, 2013, the EPA proposed a new source performance standard, which would not apply to any existing, modified, or reconstructed fossil fuel generating units, of 1,000 lbs. CO_2/MWH for large natural gas fired units (> 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for other natural gas fired units (≤ 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for fossil fuel fired units which would require partial carbon capture and storage. On October 15, 2013, the U.S. Supreme Court agreed to review a June 2012 D.C. Circuit Court of Appeals decision upholding the EPA's May 2010 regulations to decide a single narrow question: "Whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases?" Oral argument was held on February 24, 2014. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. In 1997, the U.S. Senate passed the Byrd-Hagel resolution by a unanimous vote of 95-0. The resolution stated that it is the sense of the Senate that the United States should not be a signatory to any protocol to, or other agreement regarding, the United Nations Framework Convention on Climate Change which would mandate new commitments to limit or reduce GHG emissions, unless the protocol or other agreement also mandates new specific scheduled commitments to limit or reduce GHG emissions for developing country parties within the same compliance period, or would not result in serious harm to the economy of the United States. A December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement that recognized the scientific view that the increase in global temperature should be below two degrees Celsius; includes a commitment by developed countries to provide funds, approaching $30 billion over three years with a goal of increasing to $100 billion by 2020; and establishes the "Green Climate Fund" to support mitigation, adaptation, and other climate-related activities in developing countries. To the extent that they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia and the United States, would commit to quantified economy-wide emissions targets by 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification. In December 2010, the U.N. Climate Change Conference in Cancun, Mexico resulted in an acknowledgment to reduce emissions from industrialized countries by 25 to 40 percent from 1990 emissions by 2020 and support enhanced action on climate change in the developing world. In December 2011 the U.N. Climate Change Conference in Durban, South Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the "Durban Platform for Enhanced Action". This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020. In December 2012, the U.N. Climate Change Conference in Doha, Qatar, resulted in countries agreeing to a new commitment period under the Kyoto Protocol beginning in 2020. The new Doha Amendment to establish a second commitment period requires the ratification of three-quarters of the parties to the Kyoto Protocol before it becomes effective. In November 2013, the U.N. Climate Change Conference in Warsaw, Poland advanced negotiations of a new global agreement to reduce GHG emissions by 2015. FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The

CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

In 2004, the EPA established new performance standards under Section 316(b) of the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). In 2007, the U.S. Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and the EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit's opinion and decided that Section 316(b) of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the CWA to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. On April 16, 2014, counsel for EPA informed the United States District Court in which a settlement agreement with certain NGOs set April 17, 2014 as a deadline for finalizing the Section 316(b) regulation that an additional 29 days would be needed to finalize the Section 316(b) regulation by May 16, 2014. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant's water intake channel to divert fish away from the plant's water intake system. Depending on the results of such studies and the EPA's further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

On April 19, 2013, the EPA proposed regulatory changes to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423). The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the Agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by September 30, 2015, under a consent decree entered by a U.S. District Court and the treatment obligations are proposed to phase-in as waste water discharge permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule, the future costs of compliance with these standards may require material capital expenditures.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin Plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals or estimate the possible loss or range of loss.

In December 2010, PA DEP submitted its CWA 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. In May 2011, the EPA agreed with PA DEP's recommended sulfate impairment designation which requires the development of a TMDL limit for the river, a process that will take PA DEP approximately five years. Based on the stringency of the TMDL, MP may incur significant costs to reduce sulfate discharges into the Monongahela River if the NPDES permit for the coal-fired Fort Martin plant in West Virginia is required to be modified or renewed to include more stringent effluent limitations for sulfate. However, the Hatfield's Ferry and Mitchell Plants in Pennsylvania that discharge into the Monongahela River were deactivated on October 9, 2013.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the possible loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2009, in an advance notice of public rulemaking, the EPA asserted that the large volumes of CCRs produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of CCRs, including the option of regulation as a special waste under the EPA's hazardous waste management program which could

have a significant impact on the management, beneficial use and disposal of CCRs. On April 19, 2013, the EPA stated it would "align" its proposed CCR regulations with revised waste water discharge effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) that were proposed on that date. On July 25, 2013, the House of Representatives passed H.R. 221 that would require CCRs to be regulated under Subtitle D of RCRA, as non-hazardous. On January 29, 2014, EPA agreed to take final action by December 19, 2014 on whether or not to pursue the proposed non-hazardous waste option for regulating CCRs in a Consent Decree to be filed in pending litigation. Depending on the content of the EPA's final effluent limitations rule, the specifics of any "alignment", whether EPA chooses to pursue the non-hazardous or hazardous waste option and the potential enactment of legislation, the future costs of compliance with such standards may require material capital expenditures.

On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified Consent Decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified Consent Decree also required payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On February 1, 2013, FG submitted a Feasibility Study analyzing various technical issues relevant to the closure of LBR. On March 28, 2013, FG submitted to the PA DEP a Closure Plan Major Permit Modification Application which provides for placing a final cap over LBR that would require 15 years to fully implement following the closure of LBR. The estimated cost for the proposed closure plan is $234 million, including environmental and other post closure costs. On October 3, 2013, the PA DEP issued a technical deficiency letter citing four main deficiencies with the Closure Plan: (1) seeking to accelerate the 15 year period proposed by FG for closure activities to complete closure in 9 years by commencing closure activities prior to 2017 as proposed by FG; (2) seeking to extend bond closure and post closure activities beyond the 45 years proposed by FG; (3) seeking active dewatering of the CCBs in areas where there are seeps impacted by the Impoundment; and (4) seeking an abatement plan for groundwater impacted by arsenic. FG responded to the PA DEP on December 3, 2013, and as a result of the Closure Plan, FG increased its ARO for LBR by $163 million in 2013. On April 3, 2014, PA DEP issued a permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizes FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCBs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield Plant is pursuing several options for its CCBs following December 31, 2016, and on January 23, 2013, announced a plan for beneficial use of its CCBs for mine reclamation in LaBelle, Pennsylvania. In June 2013, a complaint filed in the U.S. District Court for the Western District of Pennsylvania, alleges the LaBelle site is in violation of RCRA and state laws. In addition, on December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR.

On October 10, 2013 and December 5, 2013, complaints were filed on behalf of approximately 50 individuals against FE, FG and FES in the U.S. District Court for the Northern District of West Virginia and approximately 15 individuals against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages for alleged property damage, bodily injury and emotional distress related to the LBR CCB Impoundment. The complaints state claims for private nuisance, negligence, negligence per se, reckless conduct and trespass related to alleged groundwater contamination and odors emanating from the Impoundment. FE, FG and FES believe the claims are without merit and intend to vigorously defend themselves against the allegations made in the complaints, but, at this time, are unable to predict the outcome of the above matter or estimate the possible loss or range of loss.

FirstEnergy's future cost of compliance with any CCR regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

Certain of FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of March 31, 2014 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $129 million have been accrued through March 31, 2014. Included in the total are accrued liabilities of approximately $82 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of March 31, 2014, FirstEnergy had approximately $2.3 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDT fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDT. FE maintains a $125 million parental guaranty relating to a potential shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry. FE also maintains an $11 million parental guaranty in support of the decommissioning of the spent fuel storage facilities located at its Davis-Besse and Perry nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranty, as appropriate. By a letter dated March 28, 2013, FENOC informed the NRC that the nuclear decommissioning parental guarantee would be increased to $155 million during the second quarter of 2014. Moreover, a new parental guarantee for the Beaver Valley spent fuel storage facility of $9.5 million would also be put in place.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. A NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. On July 9, 2012, the petitioners' proposed a contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding. In an order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance. The ASLB has suspended further consideration of the petitioners' proposed contention on the environmental impacts of spent fuel storage at Davis-Besse. The NRC Staff issued Waste Confidence Draft Generic Environmental Impact Statement and published a proposed rule on this subject in September of 2013. Other contentions proposed by the petitioners in this proceeding have been rejected by the ASLB. On February 18, 2014, Beyond Nuclear and Don't Waste Michigan, two of the petitioners in the Davis-Besse license renewal proceeding, requested that the NRC institute a rulemaking on the environmental impacts of high density spent fuel storage and mitigation alternatives. On February 27, 2014, these petitioners requested a suspension of the licensing decision in the Davis-Besse license renewal proceeding to allow the NRC to complete this rulemaking. On March 21, 2014, both FENOC and the NRC opposed the request for a suspension. On April 21, 2014, the Intervenors proposed an additional contention in the license renewal proceeding related to the shield building.

As part of routine inspections of the concrete shield building at Davis-Besse Nuclear Power Station in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. The shield building is a 2 1/2-foot thick reinforced concrete structure that provides biological shielding, protection from natural phenomena including wind and tornadoes and additional shielding in the event of an accident. FENOC then expanded its sample size to include all of the existing core bores in the shield building. These inspections, which are now complete, identified additional subsurface cracking that was determined to be pre-existing, but only now identified with the aid of improved inspection technology. These inspections also revealed that the cracking condition has propagated a small amount in select areas. Preliminary analysis of the inspections results confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions.

On February 1, 2014 the Davis-Besse Nuclear Power station entered an outage to install two new steam generators, replace about a third of the unit’s 177 fuel assemblies and perform numerous safety inspections and preventative maintenance activities. These activities, including amounts spent in prior years in preparation for this outage, represent an investment of approximately $600 million by FES at Davis Besse. During the preliminary stages of the outage an area of concrete that was not filled to the expected thickness within the shield building wall was discovered at the top of the temporary construction opening that was created as part of the 2011 outage. The 2011 temporary construction opening was created to install the new reactor head. FENOC has assessed the as-found condition of the concrete and has determined the shield building would have performed its design functions. This condition within the shield building wall was repaired to conform to its original design configuration.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FENOC's nuclear facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal. Anker WV entered into a long term Coal Sales Agreement with AE Supply and MP for the supply of coal to the Harrison generating facility. Prior to the time of trial, ICG was dismissed as a defendant by the Court, which issue can be the subject of a future appeal. As a result of defendants' past and continued failure to supply the contracted coal, AE Supply and MP have incurred and will continue to incur significant additional costs for purchasing replacement coal. A non-jury trial was held from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they have incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. Defendants primarily claim that their performance is excused under a force majeure clause in the coal sales agreement and presented evidence at trial that they will continue to not provide the contracted yearly tonnage amounts. On May 2, 2011, the court entered a verdict in favor of AE Supply and MP for $104 million ($90 million in future damages and $14 million for replacement coal/interest). On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that the defendants still owed future damages, it remanded the calculation of those damages back to the trial court. The specific amount of those future damages is not known at this time, but they are expected to be calculated at a market price of coal that is significantly lower than the price used by the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on November 19, 2012. On July 2, 2013, the Petition for Allowance of Appeal was denied and in the second quarter of 2013 the now final past damage award of $15.5 million (including interest) was recognized. The case was sent back to the trial court to recalculate the future damages only and is currently in the discovery phase. A damages hearing is scheduled for May 13-14, 2014, and a ruling is expected in the fourth quarter of 2014.

Other Legal Matters

In 2010, a lawsuit was filed in Allegheny County Court of Common Pleas by Michael Goretzka, for wrongful death and negligence after his wife was fatally electrocuted when she contacted a downed power line. The trial resulted in a verdict against WP and the parties settled this matter. WP's portion of the settlement was covered by insurance subject to the remainder of its deductible. On May 30, 2012, the PPUC's Bureau of Investigation and Enforcement (I&E) filed a Formal Complaint at the PPUC regarding this matter. On February 13, 2013, WP and I&E filed a Joint Petition for Full Settlement that includes, among other things, WP's agreement to conduct an infrared inspection of its primary distribution system, modify certain training programs, and pay an $86,000 civil penalty, which settlement is subject to PPUC approval. On August 29, 2013, the PPUC entered an Order granting the Goretzka family limited party status for the sole purpose of submitting comments to the settlement and issuing the settlement for comment by the parties. On September 16, 2013, the Goretzka family filed Limited Objections to the settlement. Reply comments were filed by WP on September 30, 2013. The PPUC entered an Opinion and Order on January 9, 2014 approving the Settlement with limited modifications regarding the frequency of refresher training and reporting obligations. WP filed a letter on January 17, 2014 accepting those modifications and noting its intent to begin implementation of the settlement terms.

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 9, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. In cases where FirstEnergy determines that it is not probable, but reasonably possible that it has a material obligation, it discloses such obligations and the possible loss or range of loss if such estimate can be made. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on any of the matters referenced above, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

FIRSTENERGY SOLUTIONS CORP.

MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

FES is a wholly owned subsidiary of FE. FES provides energy-related products and services to retail and wholesale customers, and through its principal subsidiaries, FG and NG, owns or leases, operates and maintains FirstEnergy's fossil and hydroelectric generation facilities (excluding AE Supply and MP), and owns, through its subsidiary, NG, FirstEnergy's nuclear generation facilities. FENOC, a wholly owned subsidiary of FE, operates and maintains the nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FG and NG, and may purchase the uncommitted output of AE Supply, as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are subject to sale and leaseback arrangements, and pursuant to full output, cost-of-service PSAs. On February 12, 2014, FES sold its hydroelectric generation facility to LS Power and recorded a pre-tax gain of $177 million associated with the sale in the first quarter of 2014.

FES' revenues are derived primarily from sales to individual retail customers, sales to customers in the form of governmental aggregation programs, and participation in affiliated and non-affiliated POLR auctions. FES' sales are primarily concentrated in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. The demand for electricity produced and sold by FES, along with the price of that electricity, is principally impacted by conditions in competitive power markets, global economic activity as well as economic activity and weather conditions in the Midwest and Mid-Atlantic regions of the United States.

FES is exposed to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices may be impacted by the prices of other commodities, including coal and natural gas, and energy efficiency and demand response programs, as well as regulatory and legislative actions, such as MATS among other factors. FES attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies.

During the first quarter of 2014, FE completed a $500 million equity contribution to FES.

For additional information with respect to FES, please see the information contained in FirstEnergy's Management's Discussion and Analysis of Financial Condition and Results of Operations under the following subheadings, which information is incorporated by reference herein: Overview, Capital Resources and Liquidity, Guarantees and Other Assurances, Off-Balance Sheet Arrangements, Market Risk Information, Credit Risk and Outlook.

Results of Operations

Net income increased by $11 million in the first three months of 2014 compared to the same period of 2013, as more fully described below.

Revenues -

Total revenues increased $305 million, in the first three months of 2014, compared to the same period of 2013, primarily due to increased Transmission revenue and increased sales volumes in Governmental Aggregation, Mass Market sales, and POLR and Structured Sales channels, partially offset by a decline in wholesale sales. Revenues were also impacted by higher unit prices compared to 2013 as a result of increased channel pricing and ancillary pass-through revenues associated with PJM expenses incurred in January 2014.

The increase in total revenues resulted from the following sources:

	Three Months Ended March 31		Increase
Revenues by Type of Service	**2014**	**2013**	**(Decrease)**
		(In millions)	
Direct	$ 713	$ 694	$ 19
Governmental Aggregation	320	292	28
Mass Market	142	117	25
POLR and Structured	350	287	63
Wholesale	157	60	97
Transmission	107	40	67
Other	40	34	6
Total Revenues	$ 1,829	$ 1,524	$ 305

MWH Sales by Channel	Three Months Ended March 31 2014	2013	Increase (Decrease)
	(In thousands)		
Direct	12,801	13,341	(4.0)%
Governmental Aggregation	5,769	5,386	7.1 %
Mass Market	2,126	1,780	19.4 %
POLR and Structured	7,736	5,678	36.2 %
Total MWH Sales	28,432	26,185	8.6 %

The following table summarizes the price and volume factors contributing to changes in revenues:

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Financially Settled Contracts	Capacity Revenue	Total
			(In millions)		
Direct	$ (28)	$ 47	$ —	$ —	$ 19
Governmental Aggregation	21	7	—	—	28
Mass Market	23	2	—	—	25
POLR and Structured Sales	104	(41)	—	—	63
Wholesale	—	—	102	(5)	97

The increase in Direct revenues of $19 million resulted from higher unit prices, partially offset by lower sales volumes from large commercial and industrial customers. Direct sales volumes decreased due to FES' strategy to be more selective in customers targeted in response to the current market environment. The increase in Governmental Aggregation revenues of $28 million primarily reflects increased weather-related usage resulting from heating degree days that were 17% higher than the first quarter of 2013 and higher unit prices. The increase in Mass Market of $25 million resulted from the acquisition of new customers primarily in Ohio and Pennsylvania, increased weather-related usage and higher unit prices. The Direct, Governmental Aggregation and Mass Market customer base remained at 2.7 million customers as of March 31, 2014. Higher unit prices in each of the above sales channels resulted from increased channel pricing. Additionally, higher Direct unit prices were impacted by approximately $33 million of ancillary pass-through revenues associated with PJM expenses incurred in January 2014 as more fully described below.

The increase in POLR and structured revenues of $63 million was due to higher POLR and structured sales volumes primarily as a result of increased weather-related usage described above. Lower structured unit prices were primarily due to extreme weather and market conditions in January 2014 that reduced the gains on various structured financial sales contracts, partially offset by higher POLR rates associated with recent auctions.

Wholesale revenues increased $97 million due to higher net gains of $102 million on financially settled contracts, primarily with AE Supply, and a $5 million decrease in capacity revenues resulting primarily from reduced PJM tariff payments on RMR units. Increased gains on financially settled contracts with AE Supply resulted from higher market prices associated with extreme weather and market conditions in January 2014.

Transmission revenue increased $67 million due to higher congestion and ancillary revenue associated with additional retail load.

Other revenue increased $6 million primarily due to higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks since the first quarter of 2013. FES earns lease revenue associated with the equity interests it purchased.

Operating Expenses -

Total operating expenses increased by $548 million in the first three months of 2014 compared to the same period of 2013.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in the first three months of 2014 compared with the same period of 2013:

Operating Expense	Source of Change Increase (Decrease) Volumes	Prices	Financially Settled Contracts	Capacity Expense	Total
			(In millions)		
Fossil Fuel	$ 16	$ (1)	$ —	$ —	$ 15
Nuclear Fuel	(7)	11	—	—	4
Non-affiliated Purchased Power[1]	84	844	(453)	48	523
Affiliated Purchased Power	4	(2)	(70)	—	(68)

[1] Realized losses on financially settled wholesale sales contracts of $321 million resulting from higher market prices were netted in purchased power and are included within Gain on Settled Contracts.

Fuel costs increased $19 million primarily due to higher fossil generation volumes and nuclear prices from higher fuel costs, partially offset by lower nuclear generation volumes due to an increase in outages in the first quarter of 2014.

Non-affiliated purchased power costs increased $523 million due to increased prices ($844 million), higher volumes ($84 million) and higher capacity expenses ($48 million), partially offset by gains on financially settled contracts ($453 million). The increase in rate was primarily a result of higher on-peak prices from extreme weather and market conditions in January 2014, partially offset by gains on financially settled contract hedges. Higher purchased volumes were primarily due to increased sales volume requirements, planned outages, and the timing of unplanned outages and derates during on-peak hours. The increase in capacity expense was the result of higher capacity rates primarily in the MAAC zone and increased sales volumes.

Affiliated purchased power costs decreased $68 million as a result of net gains on financially settled contracts with AE Supply, partially offset by increased volume purchases from the Ohio Companies as a result of increased generation by Perry at slightly lower rates.

Other operating expenses increased $73 million in the first three months of 2014, compared to the same period of 2013 due to the following:

- Fossil operating costs decreased $12 million due primarily to fewer planned outage days in the first quarter of 2014 as compared to the same period of 2013.

- Nuclear operating costs increased $15 million as a result of higher contractor, materials and equipment costs associated with the refueling outage at Davis-Besse that began on February 1, 2014. In the same period of 2013, there was a single refueling outage at Perry that began on March 18, 2013.

- Transmission expenses increased $88 million due primarily to higher operating reserve and market-based ancillary costs associated with the extreme weather and market conditions in January 2014. These ancillary charges from PJM were for system reliability and a portion of which are able to be passed through to commercial and industrial customers. Additionally, effective June 1, 2013, network expenses associated with POLR sales in Pennsylvania became the responsibility of suppliers.

- Other operating expenses decreased $18 million primarily due to a decrease in mark-to-market expense on commodity contract positions.

Other Expense -

Total other expense decreased $85 million in the first three months of 2014, compared to the same period of 2013, primarily due to a $66 million loss on debt redemptions in connection with senior notes that were repurchased in 2013, lower net interest expense of $18 million due to debt redemptions and higher investment income of $3 million on NDT investments.

Discontinued Operations -

Discontinued operations increased net income in the first quarter of 2014 compared to the same period of last year primarily due to a pre-tax gain of approximately $177 million associated with the sale of a hydro asset described above.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Market Risk Information” in Item 2 above.

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

The management of FirstEnergy and FES, with the participation of each registrant's chief executive officer and chief financial officer, have reviewed and evaluated the effectiveness of the registrant's disclosure controls and procedures, as defined in the Securities Exchange Act of 1934, as amended, Rules 13a-15(e) and 15d-15(e), as of the end of the period covered by this report. Based on that evaluation, the chief executive officer and chief financial officer of FE and FES have concluded that their respective registrant's disclosure controls and procedures were effective as of the end of the period covered by this report.

(b) Changes in Internal Control over Financial Reporting

During the quarter ended March 31, 2014, there were no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, FE's and FES' internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information required for Part II, Item 1 is incorporated by reference to the discussions in Note 9, Regulatory Matters, and Note 10, Commitments, Guarantees and Contingencies, of the Combined Notes to the Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

During the quarter ended March 31, 2014, there were no material changes to the risk factors included in our Annual Report or Form 10-K for the year ended December 31, 2013.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

None

ITEM 6. EXHIBITS

	Exhibit Number	
FirstEnergy		
	10.1	Amendment, dated as of March 31, 2014, to the Credit Agreement, dated as of June 17, 2011, as amended as of May 8, 2012, May 8, 2013 and October 31, 2013, among FirstEnergy, The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, The Potomac Edison Company and West Penn Power Company, as borrowers, The Royal Bank of Scotland plc, as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FE's Form 8-K filed April 4, 2014, Exhibit 10-1, File No. 333-21011).
	10.2	Amendment, dated as of March 31, 2014 to the Credit Agreement, dated as of May 8, 2012, and as amended as of May 8, 2013, among FirstEnergy Transmission, LLC, American Transmission Systems, Incorporated and Trans-Allegheny Interstate Line Company, as borrowers, and PNC Bank, National Association, as administrative agent, and the lending banks and fronting banks identified therein (incorporated by reference to FE's Form 8-K filed April 4, 2014, Exhibit 10-3, File No. 333-21011).
	10.3	Term Loan Credit Agreement, dated as of March 31, 2014, among FE, as borrower, the banks named therein and The Royal Bank of Scotland, plc, as administrative agent (incorporated by reference to FE's Form 8-K filed April 4, 2014, Exhibit 10.4, File No. 333-21011).
(A)	12	Fixed charge ratio
(A)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(A)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(A)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
	101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Corp. for the period ended March 31, 2014, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Consolidated Statements of Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.
FES		
	10.1(b)	Amendment, dated as of March 31, 2014, to the Credit Agreement, dated as of June 17, 2011, as amended as of October 3, 2011, May 8, 2012, May 8, 2013 and October 31, 2013, among FirstEnergy Solutions Corp. and Allegheny Energy Supply Company, LLC, as borrowers, and JPMorgan Chase Bank, N.A., as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FES's Form 8-K filed April 4, 2014, Exhibit 10.2, File No. 000-53742).
(A)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(A)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(A)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
	101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Solutions Corp. for the period ended March 31, 2014, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

(A) Provided herein in electronic format as an exhibit.

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, neither FirstEnergy nor FES have filed as an exhibit to this Form 10-Q any instrument with respect to long-term debt if the respective total amount of securities authorized thereunder does not exceed 10% of its respective total assets, but each hereby agrees to furnish to the SEC on request any such documents.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

May 6, 2014

FIRSTENERGY CORP.

Registrant

FIRSTENERGY SOLUTIONS CORP.

Registrant

/s/ K. Jon Taylor

K. Jon Taylor

Vice President, Controller
and Chief Accounting Officer

EXHIBIT INDEX

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(A)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(A)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
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	101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Corp. for the period ended March 31, 2014, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Consolidated Statements of Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.
FES		
	10.1(b)	Amendment, dated as of March 31, 2014, to the Credit Agreement, dated as of June 17, 2011, as amended as of October 3, 2011, May 8, 2012, May 8, 2013 and October 31, 2013, among FirstEnergy Solutions Corp. and Allegheny Energy Supply Company, LLC, as borrowers, and JPMorgan Chase Bank, N.A., as administrative agent, and the lending banks, fronting banks and swing line lenders identified therein (incorporated by reference to FES's Form 8-K filed April 4, 2014, Exhibit 10.2, File No. 000-53742).
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(A) Provided herein in electronic format as an exhibit.

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Section 2: EX-12 (EXHIBIT)

EXHIBIT 12

FIRSTENERGY CORP.

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31	
	2014	2013
	(Dollars in millions)	
EARNINGS AS DEFINED IN REGULATION S-K:		
Income from continuing operations	$ 122	$ 192
Interest and other charges, before reduction for amounts capitalized and deferred	265	258
Capitalized interest	(22)	(15)
Provision for income taxes	48	114
Interest element of rentals charged to income [(1)]	24	25
Earnings as defined	$ 437	$ 574
FIXED CHARGES AS DEFINED IN REGULATION S-K:		
Interest before reduction for amounts capitalized and deferred	$ 265	$ 258
Interest element of rentals charged to income [(1)]	24	25
Fixed charges as defined	$ 289	$ 283
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	1.51	2.03

(1) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

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Section 3: EX-31.1 (EXHIBIT)

EXHIBIT 31.1

Certification

I, Anthony J. Alexander, certify that:

1. I have reviewed this report on Form 10-Q of FirstEnergy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial

reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 6, 2014

/s/ Anthony J. Alexander

Anthony J. Alexander

Chief Executive Officer

EXHIBIT 31.1

Certification

I, Donald R. Schneider, certify that:

1. I have reviewed this report on Form 10-Q of FirstEnergy Solutions Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 6, 2014

/s/ Donald R. Schneider

Donald R. Schneider

Chief Executive Officer

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Section 4: EX-31.2 (EXHIBIT)

EXHIBIT 31.2

Certification

I, James F. Pearson, certify that:

1. I have reviewed this report on Form 10-Q of FirstEnergy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 6, 2014

/s/ James F. Pearson

James F. Pearson

Chief Financial Officer

EXHIBIT 31.2

Certification

I, James F. Pearson, certify that:

1. I have reviewed this report on Form 10-Q of FirstEnergy Solutions Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 6, 2014

/s/ James F. Pearson

James F. Pearson

Chief Financial Officer

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Section 5: EX-32 (EXHIBIT)

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

In connection with the Report of FirstEnergy Corp. ("Company") on Form 10-Q for the period ending March 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each undersigned officer of the Company does hereby certify, pursuant to 18

U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Anthony J. Alexander

Anthony J. Alexander

Chief Executive Officer

/s/ James F. Pearson

James F. Pearson

Chief Financial Officer

Date: May 6, 2014

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

In connection with the Report of FirstEnergy Solutions Corp. ("Company") on Form 10-Q for the period ending March 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each undersigned officer of the Company does hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Donald R. Schneider

Donald R. Schneider
President
(Chief Executive Officer)

/s/ James F. Pearson

James F. Pearson
Chief Financial Officer

Date: May 6, 2014

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METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-E-4:

"Provide an organizational chart explaining the filing utility's corporate relationship to its affiliates – system structure."

RESPONSE:

See file ME Exhibit SRS-16 III-E-4_Attachment A.pdf and ME Exhibit SRS-16.III-E-4_Attachment B.pdf

Corporate Summary Report 03/31/14

Metropolitan Edison Company

Entity Vitals

Company Name	Metropolitan Edison Company
Domestic Jurisdiction	Pennsylvania
Formation Date	08-24-1917
Federal Tax ID	23-0870160
Charter ID	229978
Business Purpose	An electric utility company.

Entity Addresses

Address	2800 Pottsville Pike, Reading, Pennsylvania 19605-2459

Authority to do Business

Jurisdiction	New Jersey
Qualified Date	06-13-1988

Management Structure

DIRECTORS

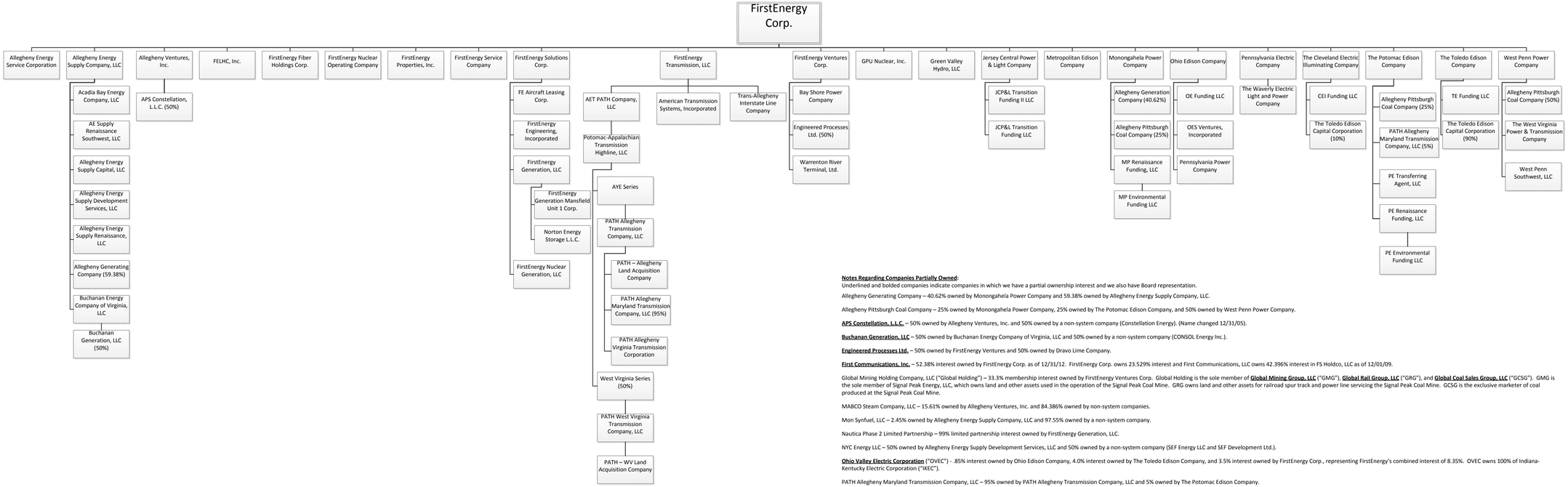
Name	Title
Alexander, Anthony J.	Director
Jones, Charles E. Jr.	Director
Pearson, James F.	Director

OFFICERS

Name	Title
Jones, Charles E. Jr.	President
Vespoli, Leila L.	Executive Vice President, Markets and Chief Legal Officer
Pearson, James F.	Senior Vice President and Chief Financial Officer
Ferguson, Rhonda S.	Vice President and Corporate Secretary
Garanich, James G.	Vice President, Tax
Karafa, David J.	Vice President
Reffner, Robert P.	Vice President and General Counsel
Staub, Steven R.	Vice President and Treasurer
Taylor, K. Jon	Vice President and Controller
Barwood, Marlene A.	Assistant Controller
Lisowski, Jason J.	Assistant Controller
Dunlap, Daniel M.	Assistant Corporate Secretary
Udovich, Edward J.	Assistant Corporate Secretary
Doran, F. Michael	Regional President

Ownership Holdings

There are no entries in this list



Notes Regarding Companies Partially Owned:
Underlined and bolded companies indicate companies in which we have a partial ownership interest and we also have Board representation.

Allegheny Generating Company – 40.62% owned by Monongahela Power Company and 59.38% owned by Allegheny Energy Supply Company, LLC.

Allegheny Pittsburgh Coal Company – 25% owned by Monongahela Power Company, 25% owned by The Potomac Edison Company, and 50% owned by West Penn Power Company.

APS Constellation, L.L.C. – 50% owned by Allegheny Ventures, Inc. and 50% owned by a non-system company (Constellation Energy). (Name changed 12/31/05).

Buchanan Generation, LLC – 50% owned by Buchanan Energy Company of Virginia, LLC and 50% owned by a non-system company (CONSOL Energy Inc.).

Engineered Processes Ltd. – 50% owned by FirstEnergy Ventures and 50% owned by Dravo Lime Company.

First Communications, Inc. – 52.38% interest owned by FirstEnergy Corp. as of 12/31/12. FirstEnergy Corp. owns 23.529% interest and First Communications, LLC owns 42.396% interest in FS Holdco, LLC as of 12/01/09.

Global Mining Holding Company, LLC ("Global Holding") – 33.3% membership interest owned by FirstEnergy Ventures Corp. Global Holding is the sole member of **Global Mining Group, LLC** ("GMG"), **Global Rail Group, LLC** ("GRG"), and **Global Coal Sales Group, LLC** ("GCSG"). GMG is the sole member of Signal Peak Energy, LLC, which owns land and other assets used in the operation of the Signal Peak Coal Mine. GRG owns land and other assets for railroad spur track and power line servicing the Signal Peak Coal Mine. GCSG is the exclusive marketer of coal produced at the Signal Peak Coal Mine.

MABCO Steam Company, LLC – 15.61% owned by Allegheny Ventures, Inc. and 84.386% owned by non-system companies.

Mon Synfuel, LLC – 2.45% owned by Allegheny Energy Supply Company, LLC and 97.55% owned by a non-system company.

Nautica Phase 2 Limited Partnership – 99% limited partnership interest owned by FirstEnergy Generation, LLC.

NYC Energy LLC – 50% owned by Allegheny Energy Supply Development Services, LLC and 50% owned by a non-system company (SEF Energy LLC and SEF Development Ltd.).

Ohio Valley Electric Corporation ("OVEC") - .85% interest owned by Ohio Edison Company, 4.0% interest owned by The Toledo Edison Company, and 3.5% interest owned by FirstEnergy Corp., representing FirstEnergy's combined interest of 8.35%. OVEC owns 100% of Indiana-Kentucky Electric Corporation ("IKEC").

PATH Allegheny Maryland Transmission Company, LLC – 95% owned by PATH Allegheny Transmission Company, LLC and 5% owned by The Potomac Edison Company.

PNBV Capital Trust – 50% interest owned by OES Ventures, Incorporated.

Potomac-Appalachian Transmission Highline, LLC – West Virginia Series – 50% owned by AET PATH Company, LLC and 50% owned by AEP Transmission Holding Company, LLC.

PowerSpan Corp. – 17.83% interest owned by FirstEnergy Corp. as of 11/23/09.

Shippingport Capital Trust – 6.55106% interest owned by The Toledo Edison Capital Corporation as of 10/13/08.

The Toledo Edison Capital Corporation – 90% interest owned by The Toledo Edison Company and 10% owned by The Cleveland Electric Illuminating Company.

Utility Associates, Inc. – 6.19% owned by Allegheny Ventures, Inc. and 93.81% owned by non-system individuals.

Virginia Capital, L.L.C. – 90% owned by The Potomac Edison Company and 99.10% owned by non-system companies.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-F-1:

"The latest available quarterly operating and financial report, annual report to the stockholders and prospectus shall be supplied for the utility and for the utility's parent, if the relationship exists."

RESPONSE:

See ME Exhibit SRS-17 A
See ME Exhibit SRS-17 B

ME Exhibit SRS-17
Attachment A
Witness: S.R. Staub

METROPOLITAN EDISON COMPANY

UNAUDITED INTERIM FINANCIAL STATEMENTS

FOR THE THREE MONTHS ENDED MARCH 31, 2014 AND 2013

METROPOLITAN EDISON COMPANY
STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

(In thousands)	Three Months Ended March 31 2014	2013
STATEMENTS OF INCOME		
REVENUES:		
Electric sales	$ 217,161	$ 218,268
Gross receipts tax collections	11,746	12,330
Total revenues	228,907	230,598
OPERATING EXPENSES:		
Purchased power	61,171	38,115
Purchased power from non-affiliates	58,000	64,234
Other operating expenses	51,934	31,140
Provision for depreciation	13,315	12,819
Amortization (deferral) of regulatory assets, net	(20,492)	20,116
General taxes	14,343	14,760
Total operating expenses	178,271	181,184
OPERATING INCOME	50,636	49,414
OTHER INCOME (EXPENSE):		
Miscellaneous income	1,067	821
Interest expense	(13,936)	(13,096)
Capitalized interest	276	69
Total other expense	(12,593)	(12,206)
INCOME BEFORE INCOME TAXES	38,043	37,208
INCOME TAXES	15,357	15,263
NET INCOME	$ 22,686	$ 21,945
STATEMENTS OF COMPREHENSIVE INCOME		
NET INCOME	$ 22,686	$ 21,945
OTHER COMPREHENSIVE LOSS		
Pensions and OPEB prior service costs	(3,464)	(4,400)
Amortized losses on derivative hedges	50	84
Other comprehensive loss	(3,414)	(4,316)
Income tax benefits on other comprehensive loss	(1,417)	(1,791)
Other comprehensive loss, net of tax	(1,997)	(2,525)
COMPREHENSIVE INCOME	$ 20,689	$ 19,420

METROPOLITAN EDISON COMPANY
BALANCE SHEETS
(Unaudited)

(In thousands, except share amounts)	March 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 158	$ 157
Receivables-		
Customers, net of allowance for uncollectible accounts of $7,408 in 2014 and $7,041 in 2013	158,947	140,386
Affiliated companies	42,691	23,419
Other	15,880	17,252
Prepaid taxes	20,635	5,932
Accumulated deferred income taxes	9,226	12,493
Other	1,795	2,827
	249,332	202,466
UTILITY PLANT:		
In service	2,732,629	2,710,676
Less — Accumulated provision for depreciation	963,892	952,242
	1,768,737	1,758,434
Construction work in progress	47,501	44,034
	1,816,238	1,802,468
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	328,859	322,227
Other	854	849
	329,713	323,076
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	416,499	416,499
Regulatory assets	147,456	140,827
Other	15,954	15,253
	579,909	572,579
	$ 2,975,192	$ 2,900,589
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 182,491	$ 181,470
Short-term borrowings		
Affiliated companies	61,845	23,281
Other	75,000	50,000
Accounts payable-		
Affiliated companies	50,478	42,111
Other	55,449	37,035
Accrued taxes	10,028	25,942
Accrued interest	8,982	15,546
Other	41,783	48,579
	486,056	423,964
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 900,000 shares -740,905 shares outstanding	827,856	827,733
Accumulated other comprehensive income	12,150	14,147
Accumulated deficit	(21,171)	(43,857)
Total common stockholder's equity	818,835	798,023
Long-term debt and other long-term obligations	617,841	619,546
	1,436,676	1,417,569
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	576,995	577,214
Accumulated deferred investment tax credits	5,522	5,603
Nuclear fuel disposal costs	44,538	44,531
Asset retirement obligations	239,181	235,224
Retirement benefits	72,436	74,252
Power purchase contract liability	21,752	27,913
Other	92,036	94,319
	1,052,460	1,059,056
COMMITMENTS AND CONTINGENCIES		
	$ 2,975,192	$ 2,900,589

METROPOLITAN EDISON COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In thousands)	Three Months Ended March 31 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 22,686	$ 21,945
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	13,315	12,819
Amortization (deferral) of other regulatory assets, net	(20,492)	20,116
Deferred purchased power and other costs, net	4,171	(1,774)
Deferred income taxes and investment tax credits, net	(234)	2,406
Change in current assets and liabilities		
Receivables	(36,461)	(8,790)
Prepayments and other current assets	(13,958)	(20,198)
Accounts payable	30,727	28,641
Accrued taxes	(15,914)	7,397
Accrued interest	(6,564)	(4,308)
Retirement benefits	(5,290)	(8,400)
Cash collateral	(5,291)	(10,735)
Other	3,276	3,910
Net cash provided from (used for) operating activities	(30,029)	43,029
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	—	300,000
Short-term borrowings, net	63,564	—
Redemptions and repayments-		
Long-term debt	—	(150,000)
Short-term borrowings, net	—	(127,717)
Return of capital payments	—	(30,000)
Other	(7)	(2,501)
Net cash provided from (used for) financing activities	63,557	(10,218)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(28,104)	(28,692)
Sales of investment securities held in trusts	54,213	56,785
Purchases of investment securities held in trusts	(57,316)	(59,868)
Asset removal costs	(2,348)	(1,019)
Other	28	(17)
Net cash used for investing activities	(33,527)	(32,811)
Net change in cash and cash equivalents	1	—
Cash and cash equivalents at beginning of period	157	157
Cash and cash equivalents at end of period	$ 158	$ 157

2013 ANNUAL REPORT

ME Exhibit SRS-17
Attachment B
Witness: S.R. Staub



FirstEnergy®

On the cover: A monopole is constructed to replace a steel tower in East Hanover, N.J., as part of a $200 million, multiyear program to enhance Jersey Central Power & Light's transmission system.

FINANCIAL HIGHLIGHTS

KEY ACCOMPLISHMENTS

- Reduced debt by approximately $1.5 billion at FirstEnergy Solutions (FES) and Allegheny Energy Supply
- Generated $2.7 billion in cash from operations
- Reduced planned capital spending on generation over the next several years by more than $1 billion
- Achieved a 9 percent increase in retail sales volume at FES
- Announced *Energizing the Future* – a $4.2 billion investment through 2017 to expand and strengthen our transmission system

FINANCIALS AT A GLANCE

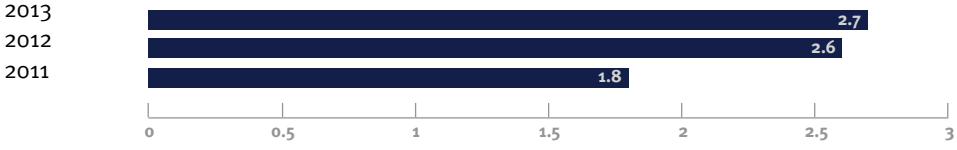
(dollars in millions, except per share amounts)

	2013	2012	2011
TOTAL REVENUES	$14,917	$15,273	$16,105
NET INCOME	$392	$771	$869
BASIC EARNINGS per common share	$0.94	$1.85	$2.22
DILUTED EARNINGS per common share	$0.94	$1.84	$2.21
DIVIDENDS PAID per common share*	$2.20	$2.20	$2.20
BOOK VALUE per common share	$30.32	$31.29	$31.75
NET CASH FROM OPERATING ACTIVITIES	$2,662	$2,320	$3,063

*In January 2014, the Board of Directors announced a quarterly dividend of $0.36 per share (equivalent to $1.44 on an annual basis)

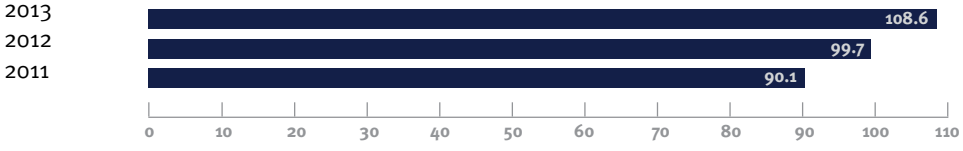
FES CUSTOMERS SERVED

(in millions)



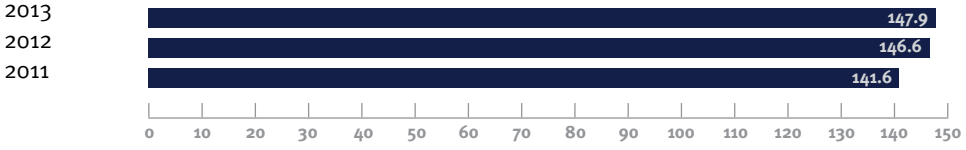
COMPETITIVE RETAIL SALES

(in millions of megawatt-hours)



DISTRIBUTION ELECTRIC SALES

(in millions of megawatt-hours)



(Note: 2011 distribution sales reflect 10 months of Allegheny Energy sales)

MESSAGE TO OUR SHAREHOLDERS



We took a number of aggressive steps in 2013 to position your company for future growth.

We reduced the size and shifted the mix of our competitive generating assets, ultimately creating a fleet that is more cost-effective, efficient and environmentally sound. We also decreased operating expenses and the size of our workforce by nearly 800 employees. And, we considerably lowered the capital requirements for environmental compliance.

More important, we refocused our business to pursue more predictable and sustainable growth in our regulated operations. We expect much of this growth over the next several years to come from investments to upgrade and expand our transmission system, which comprises approximately 24,000 miles of lines.

While these and other significant actions are helping us meet the challenges of a difficult economy, they have not been sufficient to offset the cumulative impact the recession has had on our balance sheet or earnings. For example, our distribution utility sales in 2013 were still lower than sales in 2007, the year before the economic downturn. This loss of sales over the past six years has reduced distribution revenues by approximately $1 billion. In addition, our utilities have yet to recover more than $1 billion in costs related to their response to unprecedented storm activity in 2011 and 2012.

The recession also negatively impacted our competitive operations. Market prices for competitive generation in the past three years alone have dropped more than $20 per megawatt-hour (MWH), with 85 percent of that drop – the equivalent of over $2 billion in revenues – occurring since the end of 2011.

The sustained and long-term effect of the recession, and its direct impact on our operations, undermined our ability to maintain the dividend at its previous level. As a result, in January of this year, your Board declared a quarterly dividend of $0.36 per share of outstanding stock – an annual dividend equivalent of $1.44 per share. This level better reflects the economic realities we are now facing. The dividend change is expected to preserve a solid payment for our shareholders and provide the company with additional financial flexibility to pursue regulated growth opportunities.



Above: A helicopter guides high-voltage transmission lines onto towers that run from the Davis-Besse Nuclear Power Station in Oak Harbor, Ohio, to the new Hayes Substation in Sandusky. **Right:** One of two new 470-ton steam generators is offloaded at the Port of Toledo to be installed at Davis-Besse to support its continued safe and reliable operation.



GROWING OUR REGULATED UTILITY OPERATIONS

As part of our repositioning efforts, we announced plans to expand our *Energizing the Future* initiative by making significant investments in our transmission system over the next several years. Some of these investments will involve advanced technologies designed to enhance system reliability and reduce maintenance costs. These projects also will take advantage of our ideal location as we expect to increase our load-serving capability in the Marcellus and Utica shale gas regions, where future economic growth is anticipated.

Initial efforts focus on approximately 7,500 circuit miles of transmission lines to be evaluated and rebuilt as needed, as well as the renovation of 170 substations serving Ohio Edison, The Illuminating Company, Toledo Edison and Penn Power. We expect to expand the program as we continue to strengthen one of the nation's largest transmission systems.

We're also improving the efficiency of our utility distribution system to meet the energy needs of our customers. For example, smart meter technologies show promise in improving customer service and reliability by providing faster restoration during major power outages and empowering customers to make more informed decisions about their energy use.

We recently installed 25,000 smart meters within The Illuminating Company service area as part of a three-year pilot program launched in 2011. Information gathered from this pilot will help us develop cost-effective strategies to expand our smart meter implementation efforts in Ohio. In Pennsylvania, we plan to begin installing smart meters in the Penn Power service area later in 2014, and to expand that effort to nearly all of our 2 million customers in that state by 2019.

We are encouraged by the ongoing development of shale gas resources and related businesses that should help us grow our industrial sales in the years ahead. Much of the Marcellus and Utica formations are located directly beneath FirstEnergy's service area – primarily across western Pennsylvania, eastern Ohio and West Virginia – and the full development of these resources could have a significant impact on the long-term growth of our service area.

Already, sales related to shale gas have resulted in 210 megawatts (MW) of new industrial demand and an additional 430 MW of planned expansions at customer facilities. Over the next two years, industrial sales are expected to increase by 4 percent, with opportunities for additional growth through 2018. We also should see increased commercial and residential growth related to these industrial expansions and a more robust overall economy.

PRESERVING VALUE IN OUR COMPETITIVE BUSINESS

We continue to view our competitive business as a key aspect of our long-term strategy. Although we have been challenged by weak demand for power, low capacity payments and soft energy prices, we've responded by repositioning our competitive operations through several major steps taken during the year.

We transferred ownership of our Harrison Power Station to our Mon Power utility – a move that will continue to provide our customers with cost-effective generation from this coal-based facility located in West Virginia.

Due to the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards (MATS) and other environmental regulations, we reduced the size of our generating fleet by more than 2,000 MW by deactivating the Hatfield's Ferry and Mitchell power stations.

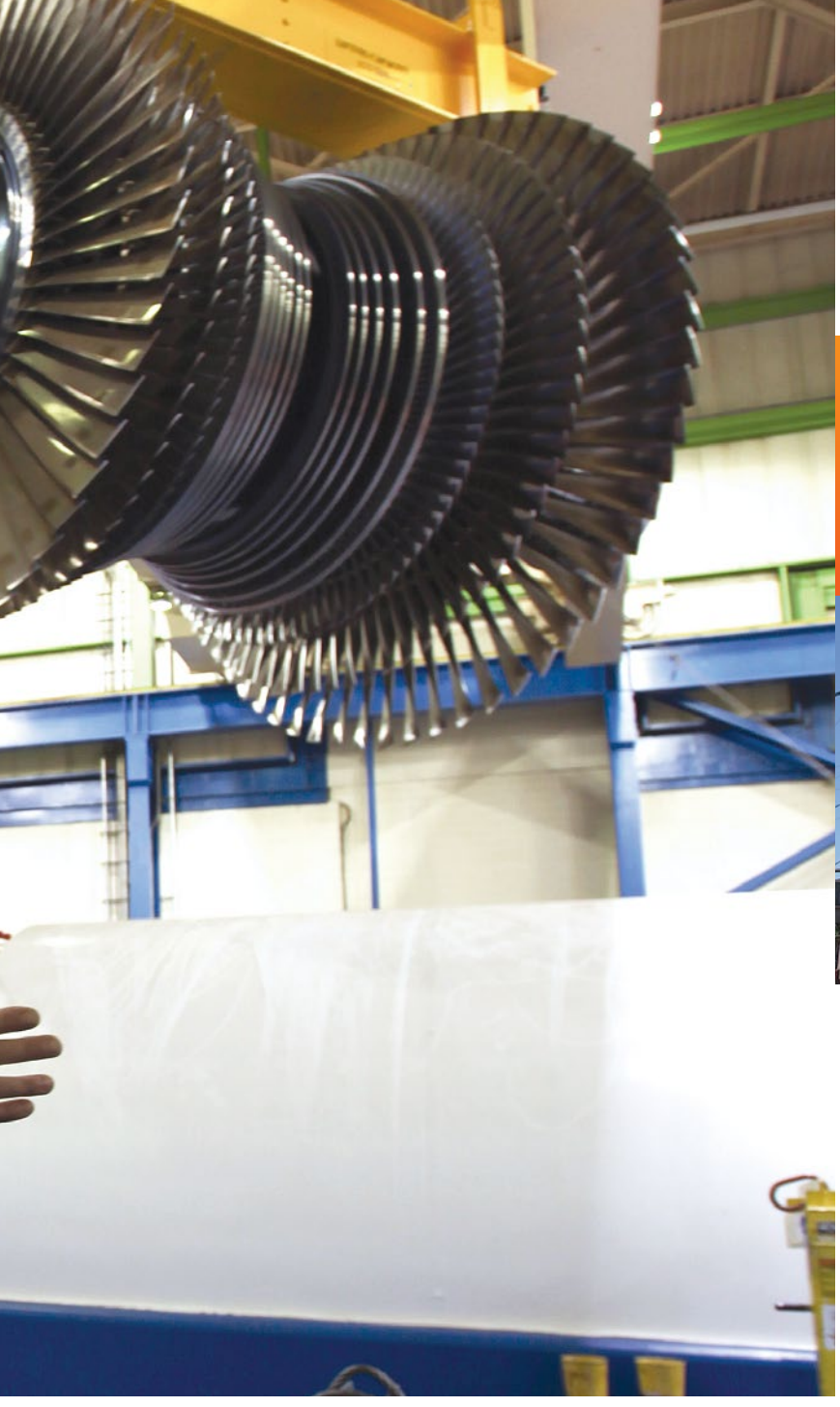
In addition, we rebalanced the mix of our generating assets with the sale of 527 MW of competitive hydroelectric capacity in 2014. Following these and previously announced actions, our competitive fleet will total approximately 13,000 MW. While the size of our competitive fleet is about the same as it was before the merger with Allegheny Energy, it is now far more effective, efficient and environmentally sound.

These transactions, combined with approximately $1.5 billion of debt reduction during 2013 at FES and Allegheny Energy Supply, have placed our competitive business in a better position to successfully navigate current and future market conditions. We've also reduced the amount of capital needed to support our generating fleet over the next several years by more than $1 billion, and continue to reduce our expenses by aggressively managing fuel, operating and maintenance costs.



As one of the largest retail energy suppliers in the U.S., FES remains focused on selectively growing its business across a variety of channels and customer groups. During the year, FES pursued highly targeted marketing strategies that increased its retail sales volume by 9 percent and its retail base by approximately 100,000 customers, bringing its total to more than 2.7 million customers. Although the realignment of our competitive generation assets and challenging retail markets are expected to result in lower sales over the near term, we will concentrate our marketing efforts on maintaining the highest-margin sales and channels. Consistent with our plans, we already have sales of more than 90 million MWH under contract for 2014, and we're well-positioned to take advantage of any increases in market and energy prices through 2016.

While we have taken significant and aggressive actions to reposition our competitive operations, we believe reforms in both capacity and energy market rules are needed. For example, in both markets, far too many regulated, subsidized and other favored resources are treated the same as competitive baseload assets. Unfortunately, some of those favored resources, such as intermittent renewables, cannot support the reliability of the grid, and others are allowed to compete but face none of the costs or risks associated with competitive markets. We will continue to work with key stakeholders to find a fair and equitable solution to these challenging issues.



Left: New low-pressure turbine rotors were installed to improve the reliability and efficiency of Unit 1 of our Beaver Valley Power Station in Shippingport, Pa. **Below:** An Ohio Edison crew member replaces a three-phase power bank as part of a service upgrade for a commercial customer in Akron.



PROTECTING THE ENVIRONMENT

FirstEnergy is committed to enhancing the environmental performance of our plants and other facilities while meeting our customers' need for safe, reliable and affordable electricity.

With the deactivation of a number of older coal-fired units and improvements in the efficiency of our nuclear units, we are reducing emissions of carbon dioxide (CO_2) across our fleet. Overall, we expect to achieve a 24 percent reduction in CO_2 emissions below 2005 levels – significantly exceeding President Obama's goal of a 17 percent reduction in CO_2 emissions by 2020, using the same 2005 baseline.

In addition, we remain on track to exceed benchmarks established by the U.S. Environmental Protection Agency's MATS and other environmental regulations while continuing to significantly reduce our expected capital investment for compliance. Our projected spend for MATS compliance is now $465 million, from an original projection of $2 billion to $3 billion. This is a direct result of the deactivation of certain plants and other cost-cutting measures.

We now operate one of the cleanest and lowest-cost fleets in the U.S. As we complete our MATS compliance program and other current projects, nearly 100 percent of our power will be generated from non- or low-emitting sources.

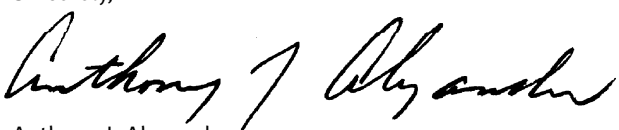
POSITIONED FOR LONG-TERM GROWTH

Our employees have overcome a number of significant hurdles in helping us reposition our company for long-term growth, and I'm confident of their ability to meet the challenges that lie ahead.

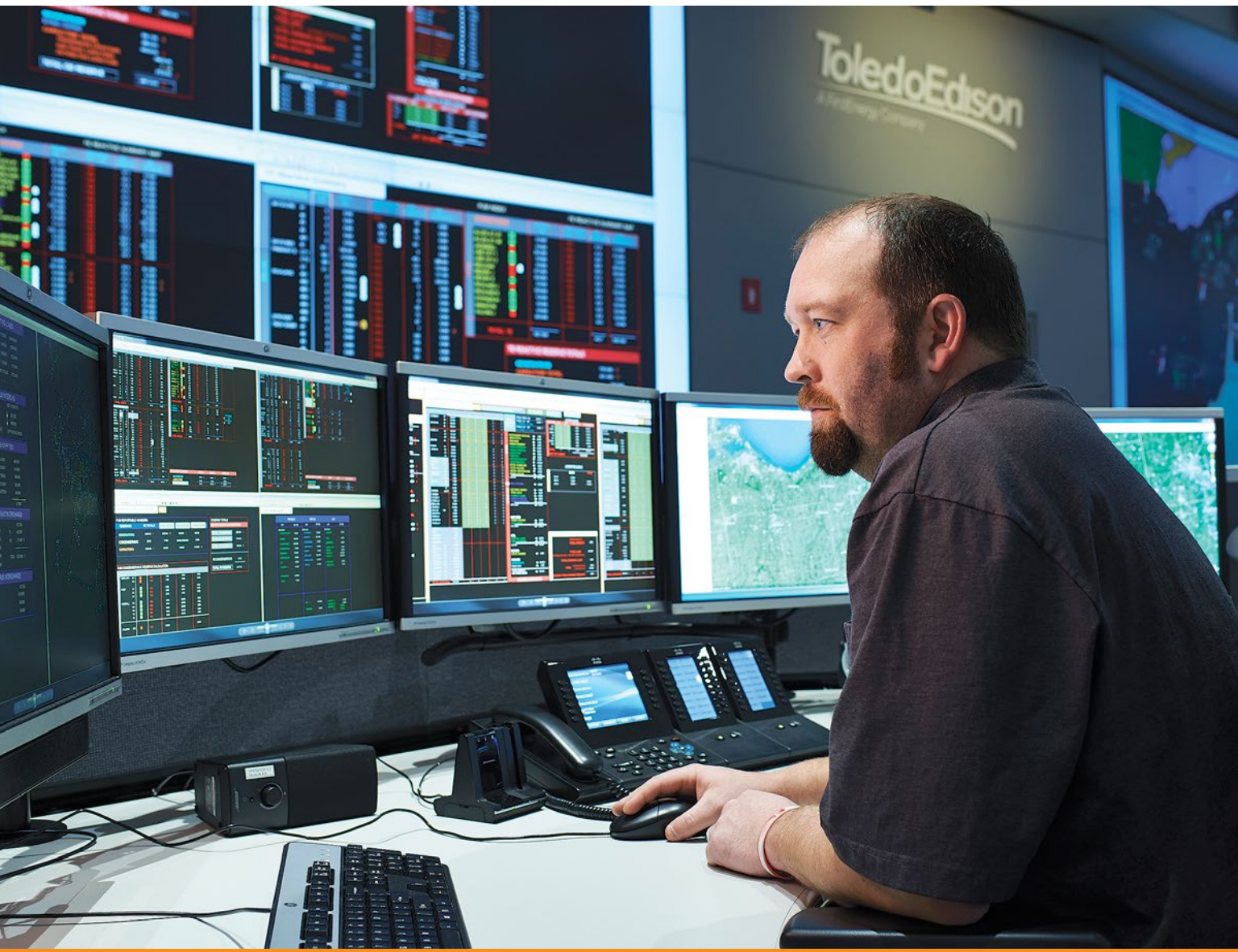
Whether it involves enhancing the efficiency of our regulated utility operations, improving the productivity of our generating fleet or increasing profitable sales at FES, our employees are committed to safe operations and their company's success. And, we are confident that the diversity and flexibility of FirstEnergy's assets will continue to offer us the best opportunities to grow our business in the future.

Our team remains focused on achieving solid results in a difficult business climate and delivering greater value to our investors. Thank you for your continued support.

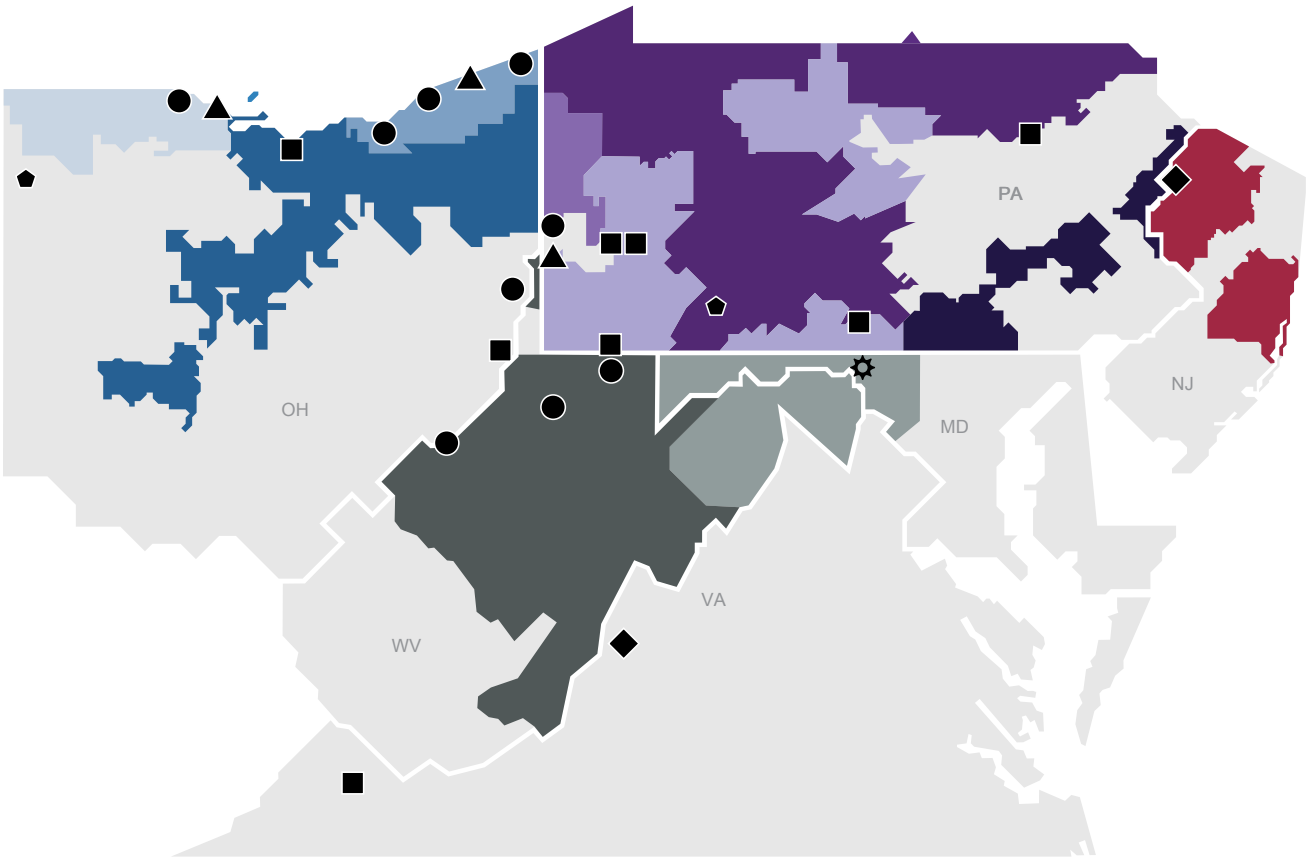
Sincerely,



Anthony J. Alexander
President and Chief Executive Officer
March 19, 2014



Our new Akron Control Center in Ohio uses advanced technologies to monitor the transmission system serving our electric utility operating companies.



CORPORATE PROFILE

FirstEnergy is a leading regional energy provider headquartered in Akron, Ohio. Our subsidiaries and affiliates are involved in the generation, transmission and distribution of electricity, as well as energy management and other energy-related services.

Our 10 utility operating companies form one of the nation's largest investor-owned electric systems based on 6 million customers served within a nearly 65,000-square-mile area of Ohio, Pennsylvania, New Jersey, West Virginia, Maryland and New York.

Our generation subsidiaries control nearly 18,000 megawatts (MW) of capacity from a diversified mix of scrubbed coal, nuclear, natural gas, oil, hydroelectric pumped-storage and contracted wind and solar resources – including nearly 1,900 MW of renewable energy. The company's transmission subsidiaries operate approximately 24,000 miles of transmission lines connecting the Midwest and Mid-Atlantic regions.

FirstEnergy Solutions, our competitive subsidiary, is one of the largest retail energy suppliers in the U.S., serving more than 2.7 million residential, commercial and industrial customers in Ohio, Pennsylvania, New Jersey, Maryland, Michigan and Illinois.

Ohio

- Ohio Edison
- The Illuminating Company
- Toledo Edison

Pennsylvania

- Met-Ed
- Penelec
- Penn Power
- West Penn Power

West Virginia/Maryland

- Mon Power
- Potomac Edison

New Jersey

- Jersey Central Power & Light

Generating Stations

- Coal
- Gas/Oil
- Hydro
- Nuclear
- Wind
- Solar

DEAR SHAREHOLDERS:

In 2013, your management team and employees made significant progress in strengthening the company's financial position, preserving its competitive business, and controlling costs.

As FirstEnergy repositions its business to achieve more sustainable growth, your Board of Directors continues to provide management with guidance on creating long-term value for its shareholders, customers and communities.

Toward that end, the Board conducted a thorough review of the dividend and determined it was prudent to declare a new quarterly dividend of $0.36 per share to more closely reflect the expected earnings from the company's regulated businesses. While this was a difficult decision, we believe this action provides shareholders with a strong dividend and presents the best path forward for FirstEnergy.

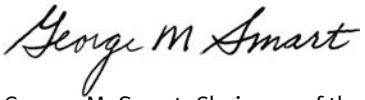
In keeping with our policy, the Board will continue to review the dividend on a quarterly basis as the company moves forward with its new strategic direction and pursues growth opportunities during the next several years. We also remain committed to ensuring your company has the appropriate corporate governance practices and policies in place.

On a personal note, let me express my gratitude on behalf of your Board to Dr. Carol A. Cartwright, who is retiring from the Board as of the 2014 Annual Meeting of Shareholders. We are thankful for the leadership and guidance Dr. Cartwright has provided during her 22 years of distinguished service to FirstEnergy and its shareholders.

I welcome Luis A. Reyes, who was elected to the Board in September 2013. Luis is a well-respected and seasoned nuclear industry veteran, with more than 36 years of experience in the field, including senior leadership positions at the U.S. Nuclear Regulatory Commission.

Your Board appreciates your ongoing trust and support. We look forward to representing your interests and working with your management team to capitalize on the opportunities that lie ahead.

Sincerely,



George M. Smart, Chairman of the Board

FIRSTENERGY BOARD OF DIRECTORS



Paul T. Addison
Retired, formerly Managing Director in the Utilities Department of Salomon Smith Barney (CitiGroup).



Anthony J. Alexander
President and Chief Executive Officer of FirstEnergy Corp.



Michael J. Anderson
Chairman of the Board and Chief Executive Officer of The Andersons, Inc. (diversified agribusiness).



Dr. Carol A. Cartwright
Retired, formerly President of Bowling Green State University. Retired President of Kent State University.



William T. Cottle
Retired, formerly Chairman of the Board, President and Chief Executive Officer of STP Nuclear Operating Company.



Robert B. Heisler, Jr.
Retired, formerly Dean of the College of Business Administration and Graduate School of Management of Kent State University. Retired Chairman of the Board of KeyBank N.A.



Julia L. Johnson
President of NetCommunications, LLC (regulatory and public affairs firm).



Ted J. Kleisner
Retired, formerly Chairman of the Board and Chief Executive Officer of Hershey Entertainment & Resorts Company.



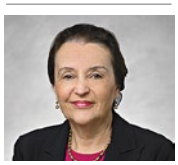
Donald T. Misheff
Retired, formerly Managing Partner of the Northeast Ohio offices of Ernst & Young LLP.



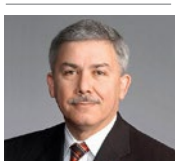
Ernest J. Novak, Jr.
Retired, formerly Managing Partner of the Cleveland office of Ernst & Young LLP.



Christopher D. Pappas
President and Chief Executive Officer of Styron LLC (plastics, latex and rubber producer).



Catherine A. Rein
Retired, formerly Senior Executive Vice President and Chief Administrative Officer of MetLife, Inc.



Luis A. Reyes
Retired, formerly Regional Administrator of the U.S. Nuclear Regulatory Commission.



George M. Smart
Non-executive Chairman of the FirstEnergy Corp. Board of Directors. Retired, formerly President of Sonoco-Phoenix, Inc.



Wes M. Taylor
Retired, formerly President of TXU Generation.

FIRSTENERGY CORP. EXECUTIVE OFFICERS*

Anthony J. Alexander
President and Chief Executive Officer

Leila L. Vespoli
Executive Vice President, Markets and Chief Legal Officer

Charles E. Jones
Executive Vice President and President, FirstEnergy Utilities

James H. Lash
President, FirstEnergy Generation

James F. Pearson
Senior Vice President and Chief Financial Officer

Lynn M. Cavalier
Senior Vice President, Human Resources

Donald R. Schneider
President, FirstEnergy Solutions

Michael J. Dowling
Senior Vice President, External Affairs

Bennett L. Gaines
Senior Vice President, Corporate Services and Chief Information Officer

K. Jon Taylor
Vice President, Controller and Chief Accounting Officer

*More detailed information on the principal occupation or employment of each of our executive officers and the principal business of any organization by which FirstEnergy Executive Officers are employed may be found on page 159 of this report.

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GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this report to identify FirstEnergy Corp. and its current and former subsidiaries:

AE	Allegheny Energy, Inc., a Maryland utility holding company that merged with a subsidiary of FirstEnergy on February 25, 2011
AESC	Allegheny Energy Service Corporation, a subsidiary of AE
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary of AE
AGC	Allegheny Generating Company, a generation subsidiary of AE Supply
Allegheny	Allegheny Energy, Inc., together with its consolidated subsidiaries
Allegheny Utilities	MP, PE and WP
ATSI	American Transmission Systems, Incorporated, formerly a direct subsidiary of FE that became a subsidiary of FET in April 2012, which owns and operates transmission facilities.
Buchanan Energy	Buchanan Energy Company of Virginia, LLC
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
Centerior	Centerior Energy Corp., former parent of CEI and TE, which merged with OE to form FirstEnergy in 1997
FE	FirstEnergy Corp., a public utility holding company
FENOC	FirstEnergy Nuclear Operating Company, which operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., which provides energy-related products and services
FESC	FirstEnergy Service Company, which provides legal, financial and other corporate support services
FET	FirstEnergy Transmission, LLC, formerly known as Allegheny Energy Transmission, LLC, a subsidiary of AE, which is the parent of ATSI and TrAIL and has a joint venture in PATH.
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FG	FirstEnergy Generation, LLC, a subsidiary of FES, which owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., together with its consolidated subsidiaries
Global Holding	Global Mining Holding Company, LLC, a joint venture between FEV, WMB Marketing Ventures, LLC and Pinesdale LLC
Global Rail	A subsidiary of Global Holding that owns coal transportation operations near Roundup, Montana
GPU	GPU, Inc., former parent of JCP&L, ME and PN, that merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
ME	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
Merger Sub	Element Merger Sub, Inc., a Maryland corporation and a wholly owned subsidiary of FirstEnergy
MP	Monongahela Power Company, a West Virginia electric utility operating subsidiary of AE
NG	FirstEnergy Nuclear Generation, LLC, a subsidiary of FES, which owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
PATH	Potomac-Appalachian Transmission Highline, LLC, a joint venture between Allegheny and a subsidiary of AEP
PATH-Allegheny	PATH Allegheny Transmission Company, LLC
PATH-WV	PATH West Virginia Transmission Company, LLC
PE	The Potomac Edison Company, a Maryland electric utility operating subsidiary of AE
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	ME, PN, Penn and WP
PN	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
Signal Peak	An indirect subsidiary of Global Holding that owns mining operations near Roundup, Montana
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TrAIL	Trans-Allegheny Interstate Line Company, a subsidiary of FET, which owns and operates transmission facilities
Utilities	OE, CEI, TE, Penn, JCP&L, ME, PN, MP, PE and WP
WP	West Penn Power Company, a Pennsylvania electric utility operating subsidiary of AE

The following abbreviations and acronyms are used to identify frequently used terms in this report:

AEP	American Electric Power Company, Inc.
AFS	Available-for-sale
ALJ	Administrative Law Judge

GLOSSARY OF TERMS, *Continued*

AMT	Alternative Minimum Tax
Anker WV	Anker West Virginia Mining Company, Inc.
Anker Coal	Anker Coal Group, Inc.
AOCI	Accumulated Other Comprehensive Income
Apple®	Apple®, iPad® and iPhone® are registered trademarks of Apple Inc.
ARO	Asset Retirement Obligation
ARR	Auction Revenue Right
ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CBA	Collective Bargaining Agreement
CBP	Competitive Bid Process
CCB	Coal Combustion By-products
CCR	Coal Combustion Residuals
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFR	Code of Federal Regulations
CFTC	Commodity Futures Trading Commission
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
CWIP	Construction Work in Progress
Dayton	The Dayton Power and Light Company
DCPD	Deferred Compensation Plan for Outside Directors
DCR	Delivery Capital Recovery
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Plan
Duke	Duke Energy Ohio, a subsidiary of Duke Energy Corporation
EBO	Early Buyout Option
EDC	Electric Distribution Company
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
ELPC	Environmental Law & Policy Center
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
ERO	Electric Reliability Organization
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plan
Facebook®	Facebook is a registered trademark of Facebook, Inc.
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
FMB	First Mortgage Bond
FPA	Federal Power Act
FTR	Financial Transmission Right
GAAP	Accounting Principles Generally Accepted in the United States of America

GLOSSARY OF TERMS, *Continued*

GHG	Greenhouse Gases
GWH	Gigawatt-hour
HCL	Hydrochloric Acid
IBEW	International Brotherhood of Electrical Workers
ICE	IntercontinentalExchange, Inc.
ICG	International Coal Group Inc.
ICP	Amended and Restated 2007 Incentive Plan
ILP	Integrated License Application Process
IRS	Internal Revenue Service
kV	Kilovolt
KWH	Kilowatt-hour
LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LITE	Local Infrastructure and Transmission Enhancement
LOC	Letter of Credit
LSE	Load Serving Entity
MATS	Mercury and Air Toxics Standards
mcf	Million cubic feet
MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.
mmBTU	One Million British Thermal Units
Moody's	Moody's Investors Service, Inc.
MOPR	Minimum Offer Price Rule
MTEP	MISO Regional Transmission Expansion Plan
MVP	Multi-Value Project
MW	Megawatt
MWH	Megawatt-hour
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGO	Non-Governmental Organization
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NNSR	Non-Attainment New Source Review
NOL	Net Operating Loss
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NYISO	New York Independent System Operator
NYPSC	New York State Public Service Commission
NYSEG	New York State Electric and Gas
OCC	Ohio Consumers' Counsel
OPEB	Other Post-Employment Benefits
OPEIU	Office and Professional Employees International Union
OTC	Over The Counter
OTTI	Other Than Temporary Impairments
OVEC	Ohio Valley Electric Corporation

GLOSSARY OF TERMS, *Continued*

PCB	Polychlorinated Biphenyl
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection LLC
PM	Particulate Matter
POLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PSEG	Public Service Electric and Gas Company
PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
R&D	Research and Development
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
REIT	Real Estate Investment Trust
RFC	Reliability*First* Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
RPM	Reliability Pricing Model
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SB221	Amended Substitute Senate Bill 221
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SERTP	Southeastern Regional Transmission Planning
SF_6	Sulfur Hexafluoride
SIP	State Implementation Plan(s) Under the Clean Air Act
SMIP	Smart Meter Implementation Plan
SO_2	Sulfur Dioxide
SOS	Standard Offer Service
SPE	Special Purpose Entity
SREC	Solar Renewable Energy Credit
SSO	Standard Service Offer
TBC	Transition Bond Charge
TDS	Total Dissolved Solid
TMDL	Total Maximum Daily Load
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
Twitter®	Twitter is a registered trademark of Twitter, Inc.
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
UWUA	Utility Workers Union of America
VIE	Variable Interest Entity
VSCC	Virginia State Corporation Commission
WVCAG	West Virginia Citizen Action Group
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

FIRSTENERGY CORP.

SELECTED FINANCIAL DATA

For the Years Ended December 31,	2013	2012	2011	2010	2009
	(In millions, except per share amounts)				
Revenues	$ 14,917	$ 15,273	$ 16,105	$ 13,306	$ 12,954
Income From Continuing Operations	$ 375	$ 755	$ 856	$ 696	$ 847
Earnings Available to FirstEnergy Corp.	$ 392	$ 770	$ 885	$ 742	$ 872
Earnings per Share of Common Stock:					
Basic - Continuing Operations	$ 0.90	$ 1.81	$ 2.19	$ 2.37	$ 2.84
Basic - Discontinued Operations (Note 20)	0.04	0.04	0.03	0.07	0.03
Basic - Earnings Available to FirstEnergy Corp.	$ 0.94	$ 1.85	$ 2.22	$ 2.44	$ 2.87
Diluted - Continuing Operations	$ 0.90	$ 1.80	$ 2.18	$ 2.35	$ 2.82
Diluted - Discontinued Operations (Note 20)	0.04	0.04	0.03	0.07	0.03
Diluted - Earnings Available to FirstEnergy Corp.	$ 0.94	$ 1.84	$ 2.21	$ 2.42	$ 2.85
Weighted Average Shares Outstanding:					
Basic	418	418	399	304	304
Diluted	419	419	401	305	306
Dividends Declared per Share of Common Stock	$ 1.65	$ 2.20	$ 2.20	$ 2.20	$ 2.20
Total Assets	$ 50,424	$ 50,494	$ 47,410	$ 35,611	$ 35,153
Capitalization as of December 31:					
Total Equity	$ 12,695	$ 13,093	$ 13,299	$ 8,952	$ 9,014
Long-Term Debt and Other Long-Term Obligations	15,831	15,179	15,716	12,579	12,008
Total Capitalization	$ 28,526	$ 28,272	$ 29,015	$ 21,531	$ 21,022

PRICE RANGE OF COMMON STOCK

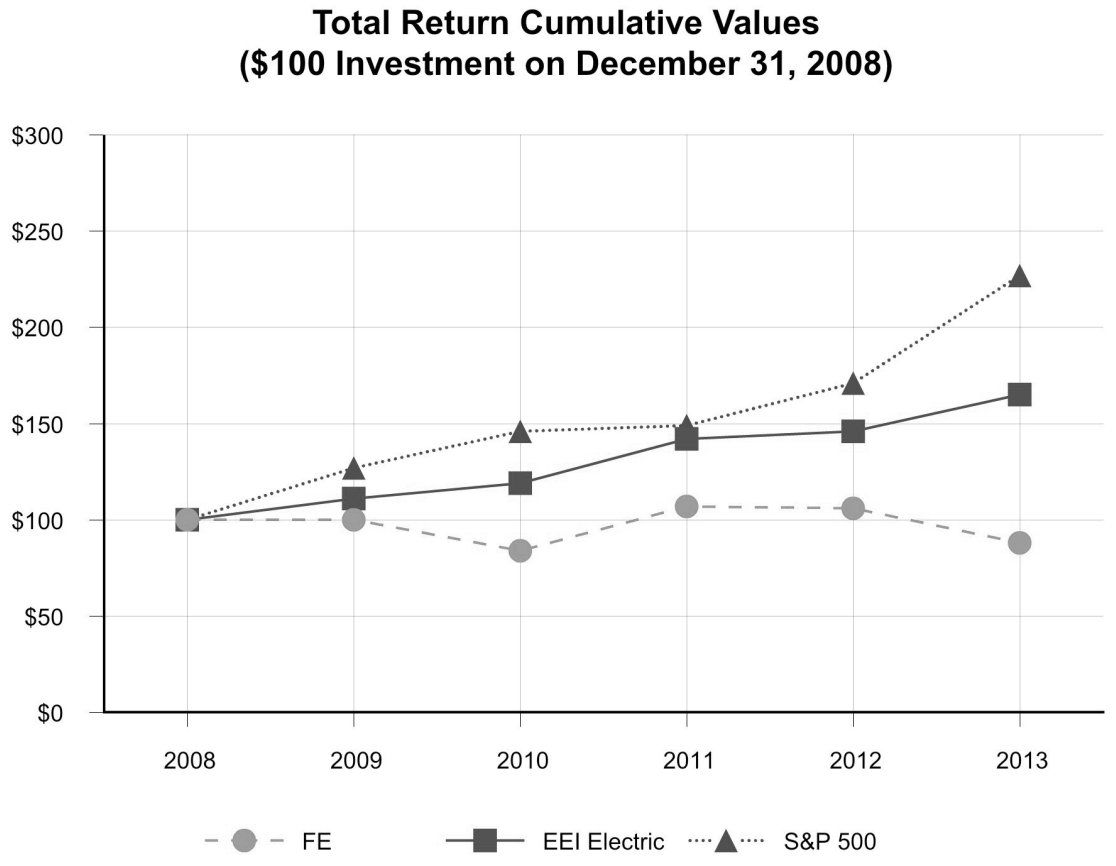
The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol “FE” and is traded on other registered exchanges.

	2013		2012	
	High	Low	High	Low
First Quarter	$ 42.50	$ 38.26	$ 46.59	$ 40.37
Second Quarter	$ 46.77	$ 35.72	$ 49.46	$ 44.64
Third Quarter	$ 39.88	$ 35.46	$ 51.14	$ 42.05
Fourth Quarter	$ 38.92	$ 31.29	$ 46.55	$ 40.47
Yearly	$ 46.77	$ 31.29	$ 51.14	$ 40.37

Closing prices are from http://finance.yahoo.com.

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2008 in FirstEnergy's common stock compared with the total cumulative returns of EEI's Index of Investor-Owned Electric Utility Companies and the S&P 500.



HOLDERS OF COMMON STOCK

There were 103,266 and 102,914 holders of 418,628,559 and 418,734,086 shares of FirstEnergy's common stock as of December 31, 2013 and January 31, 2014, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 12, Capitalization of the Combined Notes to Consolidated Financial Statements.

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Forward-Looking Statements: This Form 10-K includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "will," "intend," "believe," "estimate" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements.

Actual results may differ materially due to:

- The speed and nature of increased competition in the electric utility industry, in general, and the retail sales market in particular.
- The ability to experience growth in the Regulated Distribution and Regulated Transmission segments and to continue to successfully implement our direct retail sales strategy in the Competitive Energy Services segment.
- The accomplishment of our regulatory and operational goals in connection with our transmission plan and planned distribution rate cases and the effectiveness of our repositioning strategy.
- The impact of the regulatory process on the pending matters before FERC and in the various states in which we do business including, but not limited to, matters related to rates and pending rate cases or the WVCAG's pending appeal of the Generation Resource Transaction.
- The uncertainties of various cost recovery and cost allocation issues resulting from ATSI's realignment into PJM.
- Economic or weather conditions affecting future sales and margins such as the polar vortex or other significant weather events.
- Regulatory outcomes associated with storm restoration, including but not limited to, Hurricane Sandy, Hurricane Irene and the October snowstorm of 2011.
- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil, and availability and their impact on retail margins.
- The continued ability of our regulated utilities to recover their costs.
- Costs being higher than anticipated and the success of our policies to control costs and to mitigate low energy, capacity and market prices.
- Other legislative and regulatory changes, and revised environmental requirements, including possible GHG emission, water discharge, water intake and coal combustion residual regulations, the potential impacts of CSAPR, CAIR, and/or any laws, rules or regulations that ultimately replace CAIR, and the effects of the EPA's MATS rules including our estimated costs of compliance.
- The uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation, including NSR litigation or potential regulatory initiatives or rulemakings (including that such expenditures could result in our decision to deactivate or idle certain generating units).
- The uncertainties associated with the deactivation of certain older regulated and competitive fossil units including the impact on vendor commitments, and the timing thereof as they relate to, among other things, RMR arrangements and the reliability of the transmission grid.
- Adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to the revocation or non-renewal of necessary licenses, approvals or operating permits by the NRC or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant).
- Issues arising from the indications of cracking in the shield building and the steam generator replacement at Davis-Besse.
- The impact of future changes to the operational status or availability of our generating units.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.
- Replacement power costs being higher than anticipated or not fully hedged.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- Changes in customers' demand for power, including but not limited to, changes resulting from the implementation of state and federal energy efficiency and peak demand reduction mandates.
- The ability to accomplish or realize anticipated benefits from strategic and financial goals including, but not limited to, the ability to reduce costs and to successfully complete our announced financial plans designed to improve our credit metrics and strengthen our balance sheet, including but not limited to, the benefits from our announced dividend reduction and our proposed capital raising and debt reduction initiatives.
- Our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel transportation on such margins.
- Changing market conditions that could affect the measurement of certain liabilities and the value of assets held in our NDTs, pension trusts and other trust funds, and cause us and our subsidiaries to make additional contributions sooner, or in amounts that are larger than currently anticipated.
- The impact of changes to material accounting policies.

- The ability to access the public securities and other capital and credit markets in accordance with our announced financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.
- Actions that may be taken by credit rating agencies that could negatively affect us and our subsidiaries' access to financing, increase the costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- Changes in national and regional economic conditions affecting us, our subsidiaries and our major industrial and commercial customers, and other counterparties including fuel suppliers, with which we do business.
- The impact of any changes in tax laws or regulations or adverse tax audit results or rulings.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks and other factors discussed from time to time in our SEC filings, and other similar factors.

Dividends declared from time to time on FE's common stock during any period may in the aggregate vary from prior periods due to circumstances considered by FE's Board of Directors at the time of the actual declarations. A security rating is not a recommendation to buy or hold securities and is subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

See Item 1A. Risk Factors for additional information regarding risks that may impact our business, financial condition and results of operations.

OVERVIEW

Earnings available to FirstEnergy Corp. in 2013 were $392 million, or basic earnings of $0.94 per share of common stock ($0.94 diluted), compared with $770 million, or basic earnings of $1.85 per share of common stock ($1.84 diluted) in 2012 and $885 million, or $2.22 per basic share ($2.21 diluted), in 2011. The principal reasons for the changes in basic earnings per share are summarized below:

Change In Basic Earnings Per Share From Prior Year	2013	2012
Basic Earnings Per Share - Prior Year	$ 1.85	$ 2.22
Segment operating results[1] -		
Regulated Distribution	0.06	(0.05)
Regulated Transmission	(0.03)	—
Competitive Energy Services	(0.45)	(0.21)
Regulatory charges	(0.46)	(0.03)
Non-core asset sales/impairments	—	(0.78)
Merger-related costs	0.03	0.36
Merger accounting — commodity contracts	0.05	0.11
Net merger accretion[1][2]	—	0.01
Trust securities impairments	(0.09)	0.01
Mark-to-market adjustments-		
Pension and OPEB actuarial assumptions	1.29	(0.17)
All other	(0.07)	0.13
Plant deactivation costs	(0.74)	0.20
West Virginia asset transfer charges	(0.51)	—
Litigation resolution	—	0.06
Debt redemption costs	(0.20)	—
Restructuring costs	0.01	(0.02)
Interest expense, net of amounts capitalized	(0.01)	0.04
Investment income	—	(0.01)
Income tax legislative changes	0.08	(0.02)
Change in effective tax rate	0.11	(0.09)
Settlement of uncertain tax positions	—	0.06
Discontinued operations	—	0.01
Other	0.02	0.02
Basic Earnings Per Share	$ 0.94	$ 1.85

(1) Excludes amounts that are shown separately.
(2) Includes dilutive effect of shares issued in connection with the Allegheny merger.

FirstEnergy continued to be exposed to weak economic conditions across its multi-state utility service territory throughout 2013, as evidenced by relatively flat distribution sales over the last three years. This prolonged decrease in demand, coupled with excess generation supply in the region, has caused a period of protracted low power and capacity prices. Further, the PJM RPM Auction for 2016/2017 capacity that was conducted in May 2013 produced prices in the regions served by FirstEnergy's Competitive Energy Services segment that were lower than expected. This result is a broader indication of an underlying supply/demand imbalance that is expected to continue to affect power producers in this region, adding pressure on already depressed energy prices and potentially pushing any significant power price recovery further into the future than FirstEnergy, or the industry at large, previously expected.

Over the course of 2013, FirstEnergy took a number of actions designed to reposition the Competitive Energy Services segment, including adjusting its hedging strategy by slowing forward sales in order to capture any potential future improvements in power prices, being more selective in the customers targeted and focusing more on customers with higher profit margins. With the deactivation of the Hatfield’s Ferry and Mitchell plants and the Harrison/Pleasants asset transfer in October of 2013, as well as the sale of 527 MW of hydro assets on February 12, 2014, FirstEnergy has reduced the size of the competitive fleet and changed the

mix of its assets. While these actions will result in the competitive fleet being about the same size as before the Allegheny merger, FirstEnergy believes it is a much stronger, more efficient, and environmentally controlled platform of units.

In late 2013, FirstEnergy announced plans to grow its regulated operations - specifically its transmission segment. FirstEnergy plans to implement a transmission expansion plan designed to improve operating flexibility, increase the reliability of the regional transmission system, position capacity for future load growth and facilitate response to system events. These investments will focus primarily in ATSI, which has a formula rate recovery mechanism, but will ultimately extend throughout FirstEnergy's service area.

Operational Matters

Employee Relations

As of December 31, 2013, the IBEW, the UWUA and the OPEIU unions collectively represented approximately 48% of FirstEnergy's total employees. There are various CBAs between FirstEnergy's subsidiaries and these unions, most of which have three year terms. There were seven CBAs covering approximately 2,850 bargaining unit employees that expired in 2013. Negotiations on five of the seven CBAs resulted in new CBAs that expire in 2014, 2015, or 2016.

FirstEnergy is engaged in separate negotiations with Local 102 and Local 180 of the UWUA. The CBA with Local 102, which represents approximately 700 employees at WP and PE, expired on April 30, 2013. WP and PE have work continuation plans in place in the event of any work stoppage. The CBA with Local 180, which represents approximately 150 employees at PN, expired on August 31, 2013. After multiple bargaining sessions without an agreement on a new CBA, FirstEnergy issued a final offer, which Local 180 rejected. Beginning November 25, 2013, FirstEnergy locked out members of Local 180 and commenced its work continuation plan.

In addition, two other CBAs due to expire in 2014 were extended to 2017 prior to their expiration.

West Virginia Asset Transfer - 2013

On October 9, 2013, MP sold its approximate 8% share of Pleasants at its fair market value of $73 million to AE Supply, and AE Supply sold its approximate 80% share of Harrison to MP at its book value of $1.2 billion. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. The $1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately $527 million and a note payable to AE Supply of approximately $573 million. The note payable to AE Supply was repaid in the fourth quarter of 2013. In connection with the closing, in the fourth quarter of 2013, MP recorded a pre-tax impairment charge of approximately $322 million to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. Additionally, MP recognized a regulatory liability of approximately $23 million in the fourth quarter of 2013 representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station.

Hatfield's Ferry, Mitchell & Mad River Plant Deactivations

As a result of the cost of compliance with current and future environmental regulations and the continued low market price for electricity, FirstEnergy deactivated its 1,700-MW Hatfield's Ferry and 370-MW Mitchell coal-fired plants on October 9, 2013. In connection with the deactivations, in the second quarter of 2013, FirstEnergy recorded a pre-tax impairment of approximately $473 million to continuing operations, which also includes pre-tax impairments of $13 million related to excessive inventory at these facilities. The impairment charge is included within the results of the Competitive Energy Services segment.

Approximately 240 plant employees and generation related positions were affected by these plant deactivations. FirstEnergy recorded approximately $6 million (pre-tax) of severance related expenses that were recognized in Other operating expenses in the Consolidated Statements of Income for the year ended December 31, 2013.

On January 9, 2014, FirstEnergy deactivated the 60 MW Mad River power station in Springfield, Ohio as PJM found no reliability issues.

Davis-Besse Inspection

As part of routine inspections of the concrete shield building at Davis-Besse Nuclear Power Station in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. The shield building is a 2 1/2-foot thick reinforced concrete structure that provides biological shielding, protection from natural phenomena including wind and tornadoes and additional shielding in the event of an accident. FENOC then expanded its sample size to include all of the existing core bores in the shield building. These inspections, which are now complete, identified additional subsurface cracking that was determined to be pre-existing, but only now identified with the aid of improved inspection technology. These inspections also revealed that the cracking condition has propagated a small amount in select areas. Preliminary analysis of the inspections results confirm that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions.

Nuclear Refueling Outages

The following table includes details for the two refueling outages in 2013:

Unit	Outage Start	Returned to Service
Perry	March 18, 2013	May 2, 2013
Beaver Valley Unit 1	September 30, 2013	November 4, 2013

On March 18, 2013, Perry Nuclear Power Plant safely shut down for scheduled refueling, maintenance and a turbine upgrade. While the unit was off-line, 280 of the 748 fuel assemblies were replaced, and numerous safety inspections were conducted on the unit's reactor vessel, turbine and generator. In addition, preventative maintenance was performed on major components, including testing more than 160 valves, replacing several control rod blades and inspecting and cleaning cooling tower piping. During the outage, Perry's three low pressure turbines were replaced with new 175-ton turbine rotors.

On September 30, 2013, the 911 MW Beaver Valley Unit 1 entered into a scheduled refueling and maintenance outage, including a turbine upgrade that is designed to improve efficiency and reliability. During the outage, 60 of the 157 fuel assemblies were exchanged. Numerous inspections, maintenance activities and improvement projects designed to ensure continued safe and reliable operations have occurred. Prior to the outage, Beaver Valley operated safely and reliably for 507 consecutive days since the completion of its last refueling outage in May 2012.

Beaver Valley Unit 1 returned to service January 29, 2014, following replacement and testing of the Main Unit Transformer associated with a fault that occurred on January 6, 2014 that resulted in an automatic shutdown. In addition, during January 2014, given higher customer usage associated with extreme weather conditions and unit unavailability, including Beaver Valley Unit 1, FirstEnergy's Competitive Energy Services segment (including FES) was required to purchase higher volumes of power. Given the market conditions in PJM, the Competitive Energy Services segment (including FES) also experienced increased levels of transmission charges, primarily associated with ancillary expenses, such as synchronous and operating reserves, which are intended for reliability purposes and are socialized across all load serving entities based on load share. Certain of these transmission charges are expected to be billed to retail customers.

On February 1, 2014, the Davis-Besse Nuclear Power Station entered into an outage to install two new steam generators, replace about a third of the unit’s 177 fuel assemblies and perform numerous safety inspections and preventative maintenance activities. During the preliminary stages of the outage an area of concrete that was not filled to the expected thickness within the shield building wall was discovered at the top of the temporary construction opening that was created as part of the 2011 outage. The 2011 temporary construction opening was created to install the new reactor head. FENOC has assessed the as-found condition of the concrete and has determined the shield building would have performed its design functions. This condition within the shield building wall will be repaired during this outage to conform to its original design configuration. This condition is not expected to extend the outage.

Regulatory Matters

Ohio Alternative Energy Rider Update

Under SB221 the Ohio Companies are required to serve part of their load from renewable energy sources. During 2009 through 2011, the Ohio Companies, in accordance with SB221, conducted RFPs to secure RECs. On August 7, 2013 the PUCO disallowed the Ohio Companies' recovery of $43.4 million, plus interest, that related to 2011 RECs that were purchased in the August 2010 RFP. The Ohio Companies, along with other parties, timely filed applications for rehearing on September 6, 2013. On December 18, 2013, the PUCO denied all of the applications for rehearing. Based on the PUCO ruling, a regulatory charge of approximately $51 million, including interest, was recorded in the fourth quarter of 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. On December 24, 2013, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio. On February 10, 2014, the Supreme Court of Ohio granted the Ohio Companies' motion for stay, which went into effect on February 14, 2014. On February 18, 2014, the Office of Consumers' Counsel and the Environmental Law and Policy Center also filed appeals of the PUCO's order.

Pennsylvania Marginal Transmission Losses

On September 30, 2013, the U.S. District Court granted the PPUC’s motion to dismiss. As a result of the U.S. District Court's September 30, 2013 decision, FirstEnergy recorded a regulatory asset impairment charge of approximately $254 million (pre-tax) in the quarter ended September 30, 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. The balance of marginal transmission losses was fully refunded to customers by the second quarter of 2013. On October 29, 2013, ME and PN filed a Notice of Appeal of the U.S. District Court’s decision to dismiss the complaint with the United States Court of Appeals for the Third Circuit. On December 30, 2013, ME and PN filed a brief with the Third Circuit that explained why it was legal error for the U.S. District Court to dismiss the complaint. The PPUC filed its brief on February 3, 2014, and ME and PN filed a reply brief on February 21, 2014. Oral argument has been scheduled for April 9, 2014.

JCP&L Rate Filing Update

On September 7, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. JCP&L's rate case petition was filed on November 30, 2012. JCP&L is requesting an increase in base rate revenues of approximately $20.6 million. Hearings in the rate case have concluded. Initial briefs were filed on January 27, 2014. In the initial briefs, the Division of Rate Counsel and the Staff of the NJBPU recommended current rate revenues be decreased by $214.9 million and $207.4 million, respectively. Such amounts do not address the revenue requirements associated with the major storm events of 2011 and 2012. Reply briefs were filed on February 24, 2014.

On February 24, 2014, a Stipulation was filed with the NJBPU by JCP&L, the Division of Rate Counsel and NJBPU Staff which will allow recovery of $736 million of JCP&L's $744 million of costs related to the significant weather events of 2011 and 2012. As a result, FirstEnergy recorded a regulatory asset impairment charge of approximately $8 million (pre-tax) as of December 31, 2013, included in Amortization of regulatory assets, net within the Consolidated Statements of Income. The agreement, upon which no other party took a position to oppose or support, is now pending before the NJBPU. Recovery of 2011 storm costs will be addressed in the pending base rate case; recovery of 2012 storm costs will be determined by the NJBPU.

Financial Matters

In early 2013, FirstEnergy announced a financial plan with the intention of strengthening the balance sheets of its subsidiaries. Completion of the plan was also expected to significantly improve credit metrics at the Competitive Energy Services segment and included the net transfer of 1,476 MW of the Harrison and Pleasants power plants between AE Supply and MP, and the proposed sale of up to 1,240 MW of unregulated hydro assets. In line with these efforts, FirstEnergy and its subsidiaries executed its 2013 financial plan as described below.

FE

On March 5, 2013, FE issued in aggregate $1.5 billion of senior unsecured notes in two series: $650 million of 2.75% senior notes due March 15, 2018 and $850 million of 4.25% senior notes due March 15, 2023. The stated interest rates are subject to adjustments based upon changes in the credit ratings of FirstEnergy but will not decrease below the issued rates. The proceeds were used to repay short-term borrowings and to invest in the money pool for FES and AE Supply's use in funding a portion of their tender offers. During the second quarter of 2013, FE also completed a $1.5 billion equity contribution to FES.

On September 25, 2013, FE filed a registration statement with the SEC to register 4 million shares of common stock to be issued to registered shareholders and its employees and the employees of its subsidiaries under its Stock Investment Plan. In addition, during December 2013, FE began fulfilling certain share-based benefit plan obligations through the issuance of authorized but unissued common stock.

During December of 2013, FE entered into an agreement to extend and amend its $150 million term loan agreement with a maturity date of December 31, 2014. The maturity of the loan was extended to December 31, 2015 and the principal amount was increased to $200 million.

Competitive Energy Services

On March 28, 2013, pursuant to tender offers launched in February 2013, FES and AE Supply repurchased $369 million and $294 million, respectively, of outstanding senior notes with interest rates ranging from 5.75% to 6.8%. FES and AE Supply paid $67 million and $43 million, respectively, in premiums to repurchase the tendered senior notes.

On April 15, 2013 FES redeemed $400 million of its 4.8% senior notes due 2015 and paid $31 million of premiums in connection with the redemption.

On June 3, 2013, FG exercised a mandatory put option and repurchased approximately $235 million of PCRBs due 2023, which FG is currently holding for remarketing subject to future market and other conditions.

On September 4, 2013, FESC, on behalf of FG, AE Supply and Green Valley Hydro LLC applied for authorization from FERC to sell eleven hydroelectric power stations in Pennsylvania, Virginia and West Virginia to subsidiaries of Harbor Hydro, a subsidiary of LS Power. The hydroelectric power stations involved have a total generating capacity of approximately 527 MW, which represents less than 3 percent of FirstEnergy's competitive generation fleet output. An asset purchase agreement was entered into on August 23, and amended and restated as of September 4, 2013. On February 12, 2014, the sale of the hydroelectric power plants to LS Power closed for approximately $395 million. In the first quarter of 2014, FirstEnergy expects to recognize a pre-tax gain of approximately $145 million (FES - $177 million) related to the sale.

On November 15, 2013, AE Supply optionally redeemed $235 million of its 7.00% PCRBs due July 15, 2039 at 100% of the principal amount in connection with the deactivation of operations at Hatfield's Ferry.

Regulated Distribution and Regulated Transmission

In March 2013, ME issued $300 million of 3.50% senior unsecured notes due March 15, 2023. Proceeds from this offering were used to repay $150 million of ME's 4.95% senior unsecured notes that matured in March 2013 and repay short-term debt.

In June 2013, the Ohio Companies, through newly formed limited liability SPEs, executed a securitization transaction that resulted in the issuance of approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds with a weighted average coupon of 2.48%. The proceeds were primarily used to redeem $410 million in existing taxable bonds of the Ohio Companies with a weighted average coupon of 5.71%, including $30 million of make-whole premiums. The securitization effectively allows for the recovery of the make-whole premiums and transactional costs through the imposition of non-bypassable phase-in recovery charges on retail electric customers of the Ohio Companies pursuant to Ohio law. The $410 million redemption consisted of original maturities of $225 million due 2013, $150 million due 2015 and $35 million due 2020.

On August 21, 2013, JCP&L issued $500 million of 4.7% senior unsecured notes due April 1, 2024. The proceeds were used to pay down a portion of its short-term debt obligations, including borrowings incurred to finance a portion of Hurricane Sandy-related repair and restoration costs.

On August 28, 2013, the Ohio Companies redeemed an additional $660 million of long-term debt with interest rates ranging from 5.65% to 7.25% and maturities ranging from 2013 to 2020. In addition, approximately $120 million was paid in make-whole premiums which was deferred as a regulatory asset and will be amortized over the original life of the redeemed debt.

On October 9, 2013, MP sold its approximate 8% share of Pleasants Power Station at its fair market value of $73 million to AE Supply, and AE Supply sold its approximate 80% share of Harrison Power Station to MP at its book value of $1.2 billion. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. The $1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately $527 million and a note payable to AE Supply of approximately $573 million.

On November 27, 2013, MP issued $400 million of 4.10% FMB due April 15, 2024 and $600 million of 5.40% FMB due December 15, 2043. Proceeds from this offering were used by MP to: (i) repay at maturity $300 million of its FMB, 7.95% Series due December 15, 2013; (ii) redeem $120 million of its FMB, 6.70% Series due June 15, 2014; (iii) repay the note payable to its affiliate, AE Supply; and (iv) for working capital needs and other general corporate purposes. In connection with the closing, in the fourth quarter of 2013, MP recorded a pre-tax impairment charge of approximately $322 million to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. Concurrently, MP recognized a regulatory liability of approximately $23 million representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station.

On December 26, 2013, PN redeemed $150 million of its 5.13% Senior Notes due April 1,2014 and ME redeemed $100 million of its 4.88% Senior Notes due April 1, 2014.

Overall, these actions, consisting of the 2013 financial plan, including debt reductions at the Competitive Energy Services segment and cost savings across all of its businesses, contributed to FirstEnergy's progress in achieving its financial goals for each of its businesses in 2013, including strengthening their balance sheets, improving their liquidity and maintaining their credit ratings.

FIRSTENERGY'S BUSINESS

The Regulated Distribution segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also includes regulated electric generation facilities in West Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. Its results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls approximately 3,780 MWs of generation capacity, including the net transfer to Regulated Distribution of 1,476 MWs of capacity associated with the Harrison and Pleasants asset swap which occurred on October 9, 2013.

The service areas of, and customers served by, our regulated distribution utilities are summarized below (in thousands):

Company	Area Served	Customers Served
OE	Central and Northeastern Ohio	1,034
Penn	Western Pennsylvania	161
CEI	Northeastern Ohio	745
TE	Northwestern Ohio	308
JCP&L	Northern, Western and East Central New Jersey	1,098
ME	Eastern Pennsylvania	556
PN	Western Pennsylvania	590
WP	Southwest, South Central and Northern Pennsylvania	720
MP	Northern, Central and Southeastern West Virginia	388
PE	Western Maryland and Eastern West Virginia	393
		5,993

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP) and the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned project regulatory asset, these revenues are derived from transmission services provided pursuant to the PJM open access transmission tariff to LSEs. Its results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Competitive Energy Services segment, through FES and AE Supply, supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls approximately 14,000 MWs of capacity, including 885 MWs of capacity subject to RMR arrangements with PJM and excluding 1,476 MWs of generation capacity transferred to Regulated Distribution in connection with the Harrison and Pleasants asset swap that occurred on October 9, 2013. This segment also purchases electricity to meet sales obligations. The segment’s net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs charged by PJM to deliver energy to the segment’s customers.

The Competitive Energy Services segment derives its revenues from the sale of generation to direct and governmental aggregation, POLR and wholesale customers. The segment is exposed to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices may be impacted by the prices of other commodities, including coal and natural gas, and energy efficiency and demand response programs, as well as regulatory and legislative actions, such as MATS among other factors. The segment attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies.

The Competitive Energy Services segment economically hedges exposure to price risk on a ratable basis, which is intended to reduce the near-term financial impact of market price volatility. As of December 31, 2013, the percentage of expected physical sales economically hedged was 91% for 2014 (out of a 99 million MWH target). As of December 31, 2013, committed sales for 2015 and 2016 are approximately 49 million MWHs and 27 million MWHs, respectively.

Other and Reconciling Adjustments contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment as well as reconciling adjustments for the elimination of intersegment transactions. See Note 19, Segment Information, of the Combined Notes to Consolidated Financial Statements for further information on FirstEnergy's reportable operating segments.

FirstEnergy considers a variety of factors, including wholesale power prices, in its decision to operate, or not operate, a generating plant. If wholesale power prices represent a lower cost option, FirstEnergy may elect to fulfill its load obligation through purchasing electricity in the wholesale market as opposed to operating a generating unit. The effect of this decision on its results of operations would be to displace higher per unit fuel expense with lower per unit purchased power.

FirstEnergy engages in discussions with various commodity vendors, from time to time, regarding the impact that these and other actions may have on certain of its long-term agreements and FirstEnergy cannot provide assurance that these discussions will be satisfactorily resolved.

STRATEGY AND OUTLOOK

FirstEnergy has taken a series of actions across the company to position itself for future growth. This includes repositioning its asset mix to reflect a more regulated business profile.

The strength of FirstEnergy is based on the diversity and scale of its operations. The following describes each operating segment's plans to pursue growth initiatives in spite of the downward pressures, such as declining energy prices, a multi-year recession and flat load growth, over the past several years.

Regulated Distribution

While customer demand is expected to grow only modestly over the next several years, FirstEnergy believes early indications of a sustained recovery, and the recent signs of growth in industrial sales are encouraging. In 2014, overall load growth is expected to be 0.6%, with the majority of the increase in the industrial sector. Since FirstEnergy's utility footprint overlays the Marcellus and Utica shale territories, it expects to benefit from the manufacturing expansion related to shale gas activity and has already seen 210 MWs of demand from new industrial projects placed in service, with an additional 430 MW of expected demand from planned expansions at customer facilities. These projects are expected to result in nearly 4 percent industrial load growth over the next two years.

From a regulatory perspective, FirstEnergy intends to be more active over the next several years in rate filings for its distribution utilities than it has in the past as it looks to modernize and improve the efficiency of its utility distribution system in order to continue to provide solid reliability to customers. For example, JCP&L has a pending rate case in New Jersey and MP plans to file a rate case in West Virginia in April 2014. In addition, Penn expects to seek approval to accelerate smart meter deployment beginning later this year, and one or more of the Pennsylvania Companies are expected to file rate cases later this year in Pennsylvania.

Regulated Transmission

FirstEnergy currently expects approximately $4.2 billion in transmission investments in 2014 through 2017 focused on improving system reliability and customer service along with addressing reliability requirements associated with plant deactivations or as required by NERC and PJM. These investments will initially focus on ATSI's 69kV system in Ohio and on TrAIL, both of which receive formula rate recovery, and then move across the entire FirstEnergy footprint over time.

Competitive Energy Services

Over the past two years, FirstEnergy has taken deliberate actions to change the character of its competitive generation fleet and to stabilize this business for the future. FirstEnergy has reduced the size of the fleet and changed the mix of assets. With the deactivations of the Hatfield and Mitchell power plants, the completion of the Harrison and Pleasants asset transfer in West Virginia, the sale of certain hydro assets and eventual deactivation of units currently operating under RMR arrangements with PJM, FirstEnergy’s competitive generating portfolio will consist of more than 13,000 MWs of diversified capacity, down from approximately 18,000 MWs at the beginning of 2013.

FirstEnergy also has significantly reduced projected capital expenditures for this segment by approximately $1 billion over the next four years. Competitive Energy Services segment spending for MATS is expected to be approximately $240 million, and the majority of the remaining capital investments will be focused on projects to extend the life of FirstEnergy's nuclear assets, including the planned installation of new steam generators at Davis-Besse in 2014, and new steam generators and a new reactor head at Beaver Valley Unit 2 in 2017.

Over the next several years FirstEnergy is targeting annual retail sales of approximately 100 million MWH, primarily supported by its competitive generation assets. FirstEnergy's competitive generation portfolio, excluding RMR units, is comprised of 38% supercritical coal, 10% subcritical coal, 31% nuclear, 12% gas and oil, and 9% renewables. In total, these generating assets make up one of the cleanest, lowest-cost generation fleets in the U.S. and are expected to generate between 75 and 80 million MWHs annually.

Overall, FirstEnergy's actions are expected to place its competitive operations in a much stronger position to manage through the current power market cycle, while also retaining upside potential if and when markets improve and limiting downside risk from continued depressed conditions associated with capacity prices and forward energy prices.

Financial Outlook

FirstEnergy endeavors to manage operating and capital costs in order to achieve its financial goals, including strengthening its balance sheet, improving liquidity, improving its credit metrics and maintaining investment grade metrics for the operating companies in its Regulated Distribution, Regulated Transmission and Competitive Energy Services segments.

In January 2014, FirstEnergy’s Board of Directors declared a revised quarterly dividend of $0.36 per share of outstanding common stock. The dividend is payable March 1, 2014, to shareholders of record at the close of business on February 7, 2014. This revised dividend equates to an indicated annual dividend of $1.44 per share, reduced from the $0.55 per share quarterly dividend ($2.20 per share annually) that FirstEnergy had paid since 2008.

As of January 31, 2014, FirstEnergy's available liquidity is $2.8 billion. Capital expenditures for 2014 are expected to be approximately $3.3 billion, an increase of $1 billion from 2013 primarily due to increased transmission investments. Over the next several years, these capital expenditures, including this transmission expansion program, are expected to be funded with a combination of debt, equity issuances through the stock investment and employee benefit plans, and the projected $320 million annually in cash preserved as a result of the dividend action taken in January 2014. The Utilities and FirstEnergy's competitive generation operations expect to fund their capital expenditures over the next several years through cash from operations, debt, and, depending on the operating company, equity contributions from FE. Additionally, FirstEnergy also expects to issue long-term debt at certain Utilities and certain other subsidiaries to refinance short-term and maturing debt in the ordinary course, subject to market and other conditions. These actions are expected to continue the focus, in 2014, of maintaining strong balance sheets at the Utilities and the Competitive Energy Services segment.

The following represents a high level summary of assumptions and drivers that management expects will impact 2014 results of operations:

- Increased distribution revenue from projected sales of 148.8 million MWH in 2014 versus 147.9 million MWH in 2013.
- Increased transmission revenue due to increased investments at ATSI and TrAIL.
- Higher regulated generation operating margin primarily as a result of the West Virginia asset transfer which occurred in October 2013.
- Lower operations and maintenance expense due to reduced overall benefit expenses and lower expenses at the Competitive Energy Services segment resulting from the plant deactivations and asset sales, partially offset by increased expenses at the Regulated Distribution segment primarily due to increased maintenance costs for vegetation management.
- An effective income tax rate of 35% to 35.5%.
- Reduced commodity margin at the competitive operations.
- Two planned nuclear refueling outages in 2014, including an extended outage at Davis-Besse in 2014 for steam generator replacement, and outages at Beaver Valley Unit 1 for refueling and a transformer replacement.
- Increased pension/OPEB expense at the Regulated Distribution segment due to a lower asset balance and lower amortization of prior service cost credits.
- Higher net financing costs primarily due to higher interest expense.

Environmental Outlook

FirstEnergy continually strives to enhance environmental protection and remain good stewards of our natural resources. FirstEnergy also devotes significant resources to environmental compliance efforts, and its employees share a commitment to, and accountability for, environmental performance. The corporate focus on continuous improvement is integral to FirstEnergy's environmental programs.

More than $10 billion has been spent by FirstEnergy companies on environmental protection efforts since the initial passage of the Clean Air and Water Acts in the 1970s, and these investments demonstrate FirstEnergy's continuing commitment to the environment. Recent investments of $3 billion at the Fort Martin and Sammis Plants further reduced emissions of SO_2 by over 95%, and NOx by at least 64% from these facilities. Since 1990, NOx emissions have been reduced by more than 80%, SO_2 by more than 90%, and mercury by approximately 70% at FirstEnergy generating units.

Aggressive steps have been taken by FirstEnergy to reduce its overall CO_2 emissions by 24% below 2005 levels, 7 years ahead of the Presidential 2020 goal of a 17% carbon pollution reduction below 2005 levels. In early 2012 and 2013, FirstEnergy announced its intent to deactivate 5,429 MW of older, coal-based generation, with 2,464 MWs deactivated in September 2012, another 2,080 MWs deactivated in October, 2013, and 885 MW remaining available to meet electric system reliability concerns pursuant to RMR arrangements with PJM. As a result of these further deactivations, FirstEnergy's CO_2 emissions are expected to continue to decline, depending on economic conditions.

FirstEnergy has taken a leadership role in pursuing new ventures to test and develop new technologies that may achieve additional reductions in CO_2 emissions. These include:

- Sales of over 1 million MWH per year of wind generation.
- CO_2 sequestration testing to gain a better understanding of the potential for geological storage of CO_2.
- Supporting afforestation - growing forests on non-forested land - and other efforts designed to remove CO_2 from the environment.
- Reducing emissions of SF_6 by more than 30% between 2011 and 2012, as reported to the EPA's Mandatory Greenhouse Gas Reporting Rule.
- Supporting research to develop and evaluate cost effective sorbent materials for CO_2 capture including work by EPRI and The University of Akron.

FirstEnergy remains actively engaged in the federal and state debate over future environmental requirements and legislation by actively working with policy makers and regulators to develop fair and reasonable requirements, with the goal of reducing emissions while minimizing the economic impact on customers. Due to the significant uncertainty as to the final form or timing of a significant number of regulations and legislation at both the federal and state levels, FirstEnergy is unable to determine the potential impact and risks associated with all future environmental requirements. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the District of Columbia Circuit and was ultimately vacated by the Court on August 21, 2012. On January 24, 2013, the EPA and intervenors' petitions seeking rehearing or rehearing en banc were denied by the U.S. Court of Appeals for the District of Columbia Circuit. On December 10, 2013 the Supreme Court heard arguments on whether to reinstate the EPA's rule to reduce emissions of SO_2 and NOx, which is being challenged by several states and industry groups. The Court has ordered EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. The new MATS were finalized at the end of 2011, which contributed to FirstEnergy's decision to deactivate some of its older coal-fired generation plants. The total MATS compliance cost for the remaining fleet is estimated at $465 million with $240 million at the competitive fleet and $225 million at the regulated fleet.

FirstEnergy also has a long history of supporting research in distributed energy resources. Distributed energy resources include fuel cells, solar and wind systems or energy storage technologies located close to the customer or direct control of customer loads to provide alternatives or enhancements to the traditional electric power system. FirstEnergy is testing the world's largest utility-scale fuel cell system to determine its feasibility for augmenting generating capacity during summer peak-use periods. Through a partnership with EPRI, the Cuyahoga Valley National Park, the Department of Defense and Case Western Reserve University, two solid-oxide fuel cells were installed as part of a test program to explore the technology and the environmental benefits of distributed generation.

FirstEnergy is also evaluating the impact of distributed energy storage on the distribution system through analysis and field demonstrations of advanced battery technologies. FirstEnergy's EasyGreen® load-management program utilizes two-way communication capability with customers' non-critical equipment, such as air conditioners in New Jersey and Pennsylvania, to help manage peak loading on the electric distribution system. FirstEnergy has also made an online interactive energy efficiency tool, Home Energy Analyzer, available to our customers to help achieve electricity use reduction goals.

RISKS AND CHALLENGES

In executing our strategy, we face a number of industry and enterprise risks and challenges. See ITEM 1A. RISK FACTORS for a discussion of the risks and challenges faced by FirstEnergy, FES and their subsidiaries.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's business segments. Results of operations for the year ended December 31, 2011, include only ten months of Allegheny results which have been segregated from the pre-merger companies (FirstEnergy and its subsidiaries prior to the merger) for reporting and analysis. A reconciliation of segment financial results is provided in Note 19, Segment Information, of the Combined Notes to Consolidated Financial Statements. Certain prior year amounts have been reclassified to conform to the current year presentation. These reclassifications include, but are not limited to, the classification of discontinued operations associated with our sale of hydro assets discussed in additional detail in Note 20, Discontinued Operations and Assets Held for Sale. Net income by business segment was as follows:

				Increase (Decrease)	
	2013	2012	2011	2013 vs 2012	2012 vs 2011
	(In millions, except per share)				
Net Income (Loss) By Business Segment:					
Regulated Distribution	$ 501	$ 540	$ 488	$ (39)	$ 52
Regulated Transmission	214	226	194	(12)	32
Competitive Energy Services	(220)	215	377	(435)	(162)
Other and reconciling adjustments [1]	(103)	(210)	(190)	107	(20)
Net Income	$ 392	$ 771	$ 869	$ (379)	$ (98)
Basic Earnings Per Share:					
Continuing operations	$ 0.90	$ 1.81	$ 2.19	$ (0.91)	$ (0.38)
Discontinued operations (Note 20)	0.04	0.04	0.03	—	0.01
Net earnings per basic share	$ 0.94	$ 1.85	$ 2.22	$ (0.91)	$ (0.37)
Diluted Earnings Per Share:					
Continuing operations	$ 0.90	$ 1.80	$ 2.18	$ (0.90)	$ (0.38)
Discontinued operations (Note 20)	0.04	0.04	0.03	—	0.01
Net earnings per diluted share	$ 0.94	$ 1.84	$ 2.21	$ (0.90)	$ (0.37)

[1] Consists primarily of interest expense related to holding company debt, corporate support services revenues and expenses and the elimination of intersegment transactions.

Summary of Results of Operations — 2013 Compared with 2012

Financial results for FirstEnergy's business segments in 2013 and 2012 were as follows:

2013 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,499	$ 741	$ 5,542	$ (171)	$ 14,611
Other	239	—	183	(116)	306
Internal	—	—	770	(770)	—
Total Revenues	8,738	741	6,495	(1,057)	14,917
Operating Expenses:					
Fuel	377	—	2,119	—	2,496
Purchased power	3,308	—	1,425	(770)	3,963
Other operating expenses	1,773	131	2,007	(318)	3,593
Pension and OPEB mark-to-market	(149)	—	(107)	—	(256)
Provision for depreciation	606	114	439	43	1,202
Amortization of regulatory assets, net	529	10	—	—	539
General taxes	697	54	202	25	978
Impairment of long-lived assets	322	—	473	—	795
Total Operating Expenses	7,463	309	6,558	(1,020)	13,310
Operating Income (Loss)	1,275	432	(63)	(37)	1,607
Other Income (Expense):					
Gain (loss) on debt redemptions	—	—	(149)	17	(132)
Investment income	57	—	14	(35)	36
Interest expense	(543)	(93)	(222)	(158)	(1,016)
Capitalized interest	13	4	42	16	75
Total Other Expense	(473)	(89)	(315)	(160)	(1,037)
Income (Loss) From Continuing Operations Before Income Taxes	802	343	(378)	(197)	570
Income taxes (benefits)	301	129	(141)	(94)	195
Income (Loss) From Continuing Operations	501	214	(237)	(103)	375
Discontinued Operations, net of tax	—	—	17	—	17
Net Income (Loss)	501	214	(220)	(103)	392
Income attributable to noncontrolling interest	—	—	—	—	—
Earnings (Losses) Available to FirstEnergy Corp.	$ 501	$ 214	$ (220)	$ (103)	$ 392

2012 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,849	$ 740	$ 5,632	$ (214)	$ 15,007
Other	211	—	146	(93)	264
Internal	—	—	866	(864)	2
Total Revenues	9,060	740	6,644	(1,171)	15,273
Operating Expenses:					
Fuel	263	—	2,208	—	2,471
Purchased power	3,801	—	1,307	(862)	4,246
Other operating expenses	2,126	136	1,840	(342)	3,760
Pension and OPEB mark-to-market	392	2	215	—	609
Provision for depreciation	558	114	409	38	1,119
Deferral of storm costs	(370)	(5)	—	—	(375)
Amortization of regulatory assets, net	305	2	—	—	307
General taxes	706	44	209	25	984
Total Operating Expenses	7,781	293	6,188	(1,141)	13,121
Operating Income	1,279	447	456	(30)	2,152
Other Income (Expense):					
Investment income	84	1	66	(74)	77
Interest expense	(540)	(92)	(284)	(85)	(1,001)
Capitalized interest	12	3	44	13	72
Total Other Expense	(444)	(88)	(174)	(146)	(852)
Income From Continuing Operations Before Income Taxes	835	359	282	(176)	1,300
Income taxes	295	133	83	34	545
Income From Continuing Operations	540	226	199	(210)	755
Discontinued Operations, net of tax	—	—	16	—	16
Net Income	540	226	215	(210)	771
Income attributable to noncontrolling interest	—	—	—	1	1
Earnings Available to FirstEnergy Corp.	$ 540	$ 226	$ 215	$ (211)	$ 770

Changes Between 2013 and 2012 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ (350)	$ 1	$ (90)	$ 43	$ (396)
Other	28	—	37	(23)	42
Internal	—	—	(96)	94	(2)
Total Revenues	(322)	1	(149)	114	(356)
Operating Expenses:					
Fuel	114	—	(89)	—	25
Purchased power	(493)	—	118	92	(283)
Other operating expenses	(353)	(5)	167	24	(167)
Pension and OPEB mark-to-market	(541)	(2)	(322)	—	(865)
Provision for depreciation	48	—	30	5	83
Deferral of storm costs	370	5	—	—	375
Amortization of regulatory assets, net	224	8	—	—	232
General taxes	(9)	10	(7)	—	(6)
Impairment of long-lived assets	322	—	473	—	795
Total Operating Expenses	(318)	16	370	121	189
Operating Income (Loss)	(4)	(15)	(519)	(7)	(545)
Other Income (Expense):					
Gain (loss) on debt redemptions	—	—	(149)	17	(132)
Investment income	(27)	(1)	(52)	39	(41)
Interest expense	(3)	(1)	62	(73)	(15)
Capitalized interest	1	1	(2)	3	3
Total Other Expense	(29)	(1)	(141)	(14)	(185)
Income (Loss) From Continuing Operations Before Income Taxes	(33)	(16)	(660)	(21)	(730)
Income taxes (benefits)	6	(4)	(224)	(128)	(350)
Income (Loss) From Continuing Operations	(39)	(12)	(436)	107	(380)
Discontinued Operations, net of tax	—	—	1	—	1
Net Income (Loss)	(39)	(12)	(435)	107	(379)
Income attributable to noncontrolling interest	—	—	—	(1)	(1)
Earnings (Losses) Available to FirstEnergy Corp.	$ (39)	$ (12)	$ (435)	$ 108	$ (378)

Regulated Distribution — 2013 Compared with 2012

Net income decreased by $39 million in 2013 compared to 2012, as more fully described below.

Revenues —

The $322 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2013	2012	Increase (Decrease)
		(In millions)	
Distribution services	$ 3,762	$ 3,948	$ (186)
Generation sales:			
Retail	3,959	4,104	(145)
Wholesale	330	347	(17)
Total generation sales	4,289	4,451	(162)
Transmission	448	450	(2)
Other	239	211	28
Total Revenues	$ 8,738	$ 9,060	$ (322)

The decrease in distribution services revenue is primarily the result of a NJBPU-approved reduction to the JCP&L NUG Rider which was effective March 1, 2012 and a decrease to the ME and PN NUG riders resulting from the expiration of certain NUG contracts in 2012 and 2013. Additionally, lower recovery of energy efficiency expenses reflecting reduced costs was partially offset by an increase in the Ohio Companies' DCR rider and slightly higher distribution deliveries. Distribution deliveries increased by 0.9% in 2013 compared to 2012. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Years Ended December 31, 2013	2012	Increase (Decrease)
		(In thousands)	
Residential	54,479	53,993	0.9 %
Commercial	42,582	42,645	(0.1)%
Industrial	50,243	49,378	1.8 %
Other	584	585	(0.2)%
Total Electric Distribution MWH Deliveries	147,888	146,601	0.9 %

Higher deliveries to residential customers primarily reflects increased weather-related usage resulting from heating degree days that were 18% above 2012, and 2% above normal, partially offset by cooling degree days that were 15% below 2012, and 3% above normal. Lower deliveries to the commercial sector primarily reflect increasing energy efficiency mandates and demand response initiatives. In the industrial sector, increased sales to steel, chemical, and shale gas customers were partially offset by lower sales to automotive and paper customers. Additionally, FirstEnergy expects additional growth in the industrial sector beyond 2013 for potential shale gas projects. As the gas fields are developed, the opportunity for additional manufacturing expansion could further support growth.

The following table summarizes the price and volume factors contributing to the $162 million decrease in generation revenues in 2013 compared to 2012:

Source of Change in Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of decrease in sales volumes	$ (194)
Change in prices	49
	(145)
Wholesale:	
Effect of decrease in sales volumes	(95)
Change in prices	78
	(17)
Decrease in Generation Revenues	$ (162)

The decrease in retail generation sales volume was primarily due to increased customer shopping in the Utilities' service territories during 2013, compared to 2012. This increased customer shopping, which does not impact earnings for the Regulated Distribution segment, is expected to continue. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 81% from 79% for the Ohio Companies, 66% from 64% for the Pennsylvania Companies, 47% from 46% for PE and 52% from 50% for JCP&L. The increase in prices reflects the completion of marginal transmission loss refunds to ME and PN customers in the second quarter of 2013 and a higher generation rate at WP, which includes the recovery of transmission costs beginning in June 2013.

The decrease in wholesale generation revenues of $17 million in 2013 resulted from the expiration of NUG contracts, partially offset by higher energy and capacity prices in 2013.

Other revenues increased by $28 million primarily due to more customer requested work for OE and JCP&L in 2013 compared to 2012.

Operating Expenses —

Total operating expenses decreased by $318 million primarily due to the following:

- Fuel expense was $114 million higher in 2013 primarily related to increased generation at Fort Martin as a result of planned and forced outages in 2012 and the asset transfer between MP and AE Supply of the Harrison Power Station effective October 9, 2013.
- Purchased power costs were $493 million lower in 2013 primarily due to a decrease in volumes required as a result of increased customer shopping, higher generation, reduced NUG purchases and lower unit power supply costs.

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (68)
Change due to decreased volumes	(429)
	(497)
Purchases from affiliates:	
Change due to decreased unit costs	(10)
Change due to decreased volumes	(92)
	(102)
Decrease in costs deferred	106
Decrease in Purchased Power Costs	$ (493)

- Other operating expenses decreased $353 million primarily due to:
    - a decrease in energy efficiency program expenses of $40 million resulting from the completion of certain initiatives in Ohio and Pennsylvania, which are recoverable through rates;
    - lower distribution operating and maintenance expenses of $363 million due to lower storm related maintenance activities during 2013 compared to 2012. Maintenance costs in 2012 related to Hurricane Sandy and the "derecho" wind storm totaled $386 million;
    - higher transmission expenses of $50 million primarily due to PJM transmission costs associated with RMR units.
- Pension and OPEB mark-to-market charges decreased $541 million, primarily reflecting a higher discount rate to measure related obligations in 2013.
- Depreciation expense increased by $48 million due to a higher asset base.
- Deferral of storm costs decreased by $370 million primarily related to the absence of storm restoration expenses associated with Hurricane Sandy and the "derecho" wind storm.
- Net regulatory asset amortization increased $224 million primarily due to regulatory asset charges associated with the recovery of marginal transmission losses at ME and PN ($254 million), recovery of RECs for the Ohio Companies ($51 million), and the asset transfer between MP and AE Supply ($23 million) as well as higher default generation service cost recovery in Pennsylvania, partially offset by a reduction of NUG cost recovery at ME and PN and higher transmission cost deferrals in Ohio.
- General taxes decreased by $9 million primarily due to lower gross receipts and payroll taxes, partially offset by higher property taxes.
- Impairment of long-lived assets of $322 million reflects MP's charge to reduce the net book value of Harrison to the amount permitted to be included in rate base.

Other Expense —

Other expense increased $29 million in 2013 primarily due to lower investment income resulting from the liquidation of investments at Shippingport and lower NDT investment income.

Regulated Transmission — 2013 Compared with 2012

Net income decreased by $12 million in 2013 compared to 2012, as further described below.

Revenues —

Total revenues increased by $1 million principally due to higher revenue requirements at ATSI and TrAIL, partially offset by lower PJM network service revenues for the Utilities, reflecting lower peak loads from the prior year.

Revenues by transmission asset owner are shown in the following table:

Revenues by Transmission Asset Owner	For the Years Ended December 31, 2013	2012	Increase (Decrease)
		(In millions)	
ATSI	$ 219	$ 213	$ 6
TrAIL	207	200	7
PATH	20	18	2
Utilities	295	309	(14)
Total Revenues	$ 741	$ 740	$ 1

Operating Expenses —

Total operating expenses increased by $16 million principally due to higher regulatory asset amortization related to the PATH abandonment and higher property taxes reflecting a higher asset base.

Competitive Energy Services — 2013 Compared with 2012

Net income decreased by $435 million in 2013, compared to 2012, as more fully described below.

Revenues —

Total revenues decreased by $149 million in 2013, compared to 2012, primarily due to a decline in wholesale sales. Although MWH sales increased 5.8% compared to the prior period, revenues were adversely impacted by lower unit prices compared to 2012 as a result of a significant decrease in power prices beginning in the fourth quarter of 2011 when the 2013 competitive retail sales position was only approximately 50% committed. These decreases were partially offset by growth in Governmental Aggregation, Mass Market, and POLR and Structured sales channels. The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2013	2012	Increase (Decrease)
		(In millions)	
Direct	$ 2,913	$ 2,934	$ (21)
Governmental Aggregation	1,185	1,029	156
Mass Market	448	352	96
POLR and Structured	1,279	1,265	14
Wholesale[(1)]	341	751	(410)
Transmission	144	160	(16)
RECs	2	7	(5)
Other	183	146	37
Total Revenues	$ 6,495	$ 6,644	$ (149)

[(1)] Excludes wholesale revenues classified as Discontinued Operations.

MWH Sales by Channel	For the Years Ended December 31, 2013	2012	Increase (Decrease)
	(In thousands)		
Direct	56,145	54,528	3.0 %
Governmental Aggregation	20,859	17,287	20.7 %
Mass Market	6,761	5,212	29.7 %
POLR and Structured	24,805	22,664	9.4 %
Wholesale[(1)]	1,250	4,091	(69.4)%
Total MWH Sales	109,820	103,782	5.8 %

[(1)] Excludes wholesale sales classified as Discontinued Operations.

The following tables summarize the price and volume factors contributing to changes in revenues:

MWH Sales Channel:	Source of Change in Revenues Increase (Decrease)				
	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
			(In millions)		
Direct	$ 87	$ (108)	$ —	$ —	$ (21)
Governmental Aggregation	213	(57)	—	—	156
Mass Market	105	(9)	—	—	96
POLR and Structured Sales	130	(116)	—	—	14
Wholesale[(1)]	(74)	4	(204)	(136)	(410)

[(1)] Excludes wholesale sales classified as Discontinued Operations.

The decrease in Direct revenues of $21 million resulted from lower unit prices, partially offset by higher sales volumes due to the acquisition of new larger customers in central and southern Ohio. The increase in Governmental Aggregation of $156 million resulted from the acquisition of new customers primarily in Illinois, partially offset by lower unit prices. The increase in Mass Market of $96 million resulted from the acquisition of new customers primarily in Ohio, Illinois and Pennsylvania, partially offset by lower unit prices. The Direct, Governmental Aggregation and Mass Market customer base increased to 2.7 million customers as of December 31, 2013, as compared to 2.6 million as of December 31, 2012.

The increase in POLR and structured revenues of $14 million was due to higher structured sales, partially offset by lower prices and lower POLR sales. The decline in POLR sales is in line with FES' strategy to realign its sales portfolio.

Wholesale revenues decreased $410 million due to a $204 million reduction in gains on financially settled contracts, a $136 million decrease in capacity revenues primarily from lower capacity prices, and a $70 million decrease in short-term (net hourly positions) transactions. The decrease in wholesale sales volumes was due to lower generation available for sale primarily as a result of the asset transfer between MP and AE Supply, plants that were deactivated in 2012 and 2013, and those under RMR arrangements, and higher retail sales volumes.

Transmission revenue decreased $16 million due primarily to lower congestion and ancillary revenue.

Other revenue increased $37 million due primarily to an $17 million pre-tax gain on the sale of property to a regulated affiliate and a $19 million increase in income from FEV's equity method investment in Global Holding.

Operating Expenses —

Total operating expenses increased by $370 million in 2013 due to the following:

- Fuel costs decreased $89 million primarily due to lower volumes associated with plants that were deactivated in 2013 and 2012, those under RMR arrangements, the asset transfer between MP and AE Supply and lower unit prices associated with new and restructured contracts, partially offset by settlements associated with past damages on transportation contracts.

- Purchased power costs increased $118 million due to higher volumes ($402 million) and increased prices ($81 million), partially offset by reduced losses on financially settled contracts ($239 million) and lower capacity expenses ($126 million). The increase in rate primarily resulted from higher on-peak prices compared to 2012. The increase in purchased power volumes relates to the overall increase in sales volumes and decrease in fossil generation.

- Fossil operating costs decreased by $25 million due primarily to lower labor costs resulting from previously deactivated units and lower compensation and benefit expenses associated with plan changes.

- Nuclear operating costs decreased by $21 million due primarily to lower labor costs and lower compensation and benefit expenses associated with plan changes.

- Transmission expenses increased $101 million due primarily to higher retail load and higher network costs associated with POLR sales in Pennsylvania, partially offset by lower congestion costs as well as credits received in 2013 for previously incurred PJM transmission costs associated with RMR units in the ATSI zone. Effective June 1, 2013, network transmission costs became the responsibility of suppliers of POLR sales in Pennsylvania.

- Impairments of long-lived assets increased $473 million due to the decision to deactivate the Hatfield and Mitchell generating plants. The plants were deactivated on October 9, 2013.

- General taxes decreased by $7 million due primarily to lower payroll taxes as a result of lower labor costs noted above, partially offset by higher property taxes.
- Depreciation expense increased $30 million primarily due to a higher asset base and accelerated depreciation associated with the deactivations noted above.
- Other operating expenses decreased by $210 million primarily due to a $322 million decrease in pensions and OPEB mark-to-market charges primarily reflecting a higher discount rate to measure related obligations in 2013, partially offset by an increase in mark-to-market expense on commodity contract positions ($98 million) and increased retail expenses ($26 million).

Other Expense —

Total other expense in 2013 increased $141 million compared to 2012 due to a $149 million loss on debt redemptions in connection with senior notes that were repurchased, lower investment income of $52 million due to higher OTTI on the NDT investments, partially offset by lower net interest expense of $60 million due to debt redemptions and repurchases.

Other — 2013 Compared with 2012

Financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $107 million increase in net income in 2013 compared to 2012 primarily due to lower income tax expense of $128 million primarily resulting from reduced pre-tax income and a lower effective tax rate and increased investment income of $39 million. Partially offsetting the increase was higher interest expense of $73 million due to the issuance of $1.5 billion of senior unsecured notes in the first quarter of 2013.

Summary of Results of Operations — 2012 Compared with 2011

Financial results for FirstEnergy's business segments in 2012 and 2011 were as follows:

2012 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,849	$ 740	$ 5,632	$ (214)	$ 15,007
Other	211	—	146	(93)	264
Internal	—	—	866	(864)	2
Total Revenues	9,060	740	6,644	(1,171)	15,273
Operating Expenses:					
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Purchased power	3,801	—	1,307	(862)	4,246
Other operating expenses	2,126	136	1,840	(342)	3,760
Pension and OPEB mark-to-market	392	2	215	—	609
Provision for depreciation	558	114	409	38	1,119
Deferral of storm costs	(370)	(5)	—	—	(375)
Amortization of regulatory assets, net	305	2	—	—	307
General taxes	706	44	209	25	984
Total Operating Expenses	7,781	293	6,188	(1,141)	13,121
Operating Income	1,279	447	456	(30)	2,152
Other Income (Expense):					
Investment income	84	1	66	(74)	77
Interest expense	(540)	(92)	(284)	(85)	(1,001)
Capitalized interest	12	3	44	13	72
Total Other Expense	(444)	(88)	(174)	(146)	(852)
Income From Continuing Operations Before Income Taxes	835	359	282	(176)	1,300
Income taxes	295	133	83	34	545
Income From Continuing Operations	540	226	199	(210)	755
Discontinued Operations, net of tax	—	—	16	—	16
Net Income	540	226	215	(210)	771
Income attributable to noncontrolling interest	—	—	—	1	1
Earnings Available to FirstEnergy Corp.	$ 540	$ 226	$ 215	$ (211)	$ 770

2011 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 9,689	$ 660	$ 5,616	$ (24)	$ 15,941
Other	224	—	167	(294)	97
Internal	—	—	1,237	(1,170)	67
Total Revenues	9,913	660	7,020	(1,488)	16,105
Operating Expenses:					
Fuel	268	—	2,049	—	2,317
Purchased power	4,667	—	1,379	(1,172)	4,874
Other operating expenses	1,842	113	2,241	(247)	3,949
Pension and OPEB mark-to-market	290	2	215	—	507
Provision for depreciation	523	104	411	24	1,062
Deferral of storm costs	(145)	—	—	—	(145)
Amortization of regulatory assets, net	468	6	—	—	474
General taxes	717	40	199	21	977
Impairment of long-lived assets	87	—	315	11	413
Total Operating Expenses	8,717	265	6,809	(1,363)	14,428
Operating Income	1,196	395	211	(125)	1,677
Other Income (Expense):					
Gain on partial sale of Signal Peak	—	—	569	—	569
Investment income	99	—	56	(41)	114
Interest expense	(530)	(89)	(298)	(91)	(1,008)
Capitalized interest	10	2	40	18	70
Total Other Income (Expense)	(421)	(87)	367	(114)	(255)
Income From Continuing Operations Before Income Taxes	775	308	578	(239)	1,422
Income taxes	287	114	214	(49)	566
Income From Continuing Operations	488	194	364	(190)	856
Discontinued Operations, net of tax	—	—	13	—	13
Net Income	488	194	377	(190)	869
Income (loss) attributable to noncontrolling interest	—	—	—	(16)	(16)
Earnings Available to FirstEnergy Corp.	$ 488	$ 194	$ 377	$ (174)	$ 885

Changes Between 2012 and 2011 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ (840)	$ 80	$ 16	$ (190)	$ (934)
Other	(13)	—	(21)	201	167
Internal	—	—	(371)	306	(65)
Total Revenues	(853)	80	(376)	317	(832)
Operating Expenses:					
Fuel	(5)	—	159	—	154
Purchased power	(866)	—	(72)	310	(628)
Other operating expenses	284	23	(401)	(95)	(189)
Pension and OPEB mark-to-market	102	—	—	—	102
Provision for depreciation	35	10	(2)	14	57
Deferral of storm costs	(225)	(5)	—	—	(230)
Amortization of regulatory assets, net	(163)	(4)	—	—	(167)
General taxes	(11)	4	10	4	7
Impairment of long-lived assets	(87)	—	(315)	(11)	(413)
Total Operating Expenses	(936)	28	(621)	222	(1,307)
Operating Income	83	52	245	95	475
Other Income (Expense):					
Gain on partial sale of Signal Peak	—	—	(569)	—	(569)
Investment income	(15)	1	10	(33)	(37)
Interest expense	(10)	(3)	14	6	7
Capitalized interest	2	1	4	(5)	2
Total Other Expense	(23)	(1)	(541)	(32)	(597)
Income From Continuing Operations Before Income Taxes	60	51	(296)	63	(122)
Income taxes	8	19	(131)	83	(21)
Income From Continuing Operations	52	32	(165)	(20)	(101)
Discontinued Operations, net of tax	—	—	3	—	3
Net Income	52	32	(162)	(20)	(98)
Income attributable to noncontrolling interest	—	—	—	17	17
Earnings Available to FirstEnergy Corp.	$ 52	$ 32	$ (162)	$ (37)	$ (115)

Regulated Distribution — 2012 Compared with 2011

Net income increased by $52 million in 2012 compared to 2011, primarily due to two additional months of earnings from the Allegheny Utilities and lower merger-related costs, partially offset by decreased weather-related customer usage in 2012.

Results of operations for the year ended December 31, 2011, include only ten months of Allegheny results which have been segregated from the pre-merger companies (FirstEnergy and its subsidiaries prior to the merger) for reporting and analysis.

Revenues —

The $853 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2012	2011	Increase (Decrease)
		(In millions)	
Pre-merger companies:			
Distribution services	$ 3,247	$ 3,428	$ (181)
Generation sales:			
Retail	2,540	3,266	(726)
Wholesale	206	377	(171)
Total generation sales	2,746	3,643	(897)
Transmission	300	219	81
Other	167	180	(13)
Total pre-merger companies	6,460	7,470	(1,010)
Allegheny Utilities[(1)]	2,600	2,443	157
Total Revenues	$ 9,060	$ 9,913	$ (853)

(1) Allegheny results include 12 months in 2012 and 10 months in 2011.

The decrease in distribution services revenue for the pre-merger companies reflects lower distribution deliveries (described below), the suspension of Ohio's deferred distribution cost recovery rider in December 2011 and an NJBPU-approved reduction to the JCP&L NUG Rider which became effective on March 1, 2012, partially offset by an increase in Ohio's energy efficiency rider and a PPUC-approved increase to the ME and PN NUG Riders which also became effective on March 1, 2012. Distribution deliveries (excluding the Allegheny Utilities) decreased by 1.7% in 2012 from 2011. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Year Ended December 31 2012	2011	Increase (Decrease)
		(In thousands)	
Pre-merger companies:			
Residential	38,493	39,369	(2.2)%
Commercial	32,149	32,610	(1.4)%
Industrial	35,139	35,637	(1.4)%
Other	492	513	(4.1)%
Total pre-merger companies	106,273	108,129	(1.7)%
Allegheny Utilities[(1)]	40,328	33,449	20.6 %
Total Electric Distribution MWH Deliveries	146,601	141,578	3.5 %

(1) Allegheny results include 12 months in 2012 and 10 months in 2011.

Lower deliveries to residential and commercial customers for the pre-merger companies primarily reflect decreased weather-related usage resulting from heating degree days that were 10% below 2011 levels, a slight reduction in the number of residential customers and declining average customer consumption caused, in part by, increasing energy efficiency mandates and demand response

initiatives. In the industrial sector, MWH deliveries decreased 1.4%, reflecting slight decreases in deliveries to steel, petroleum and automotive customers.

The following table summarizes the price and volume factors contributing to the $897 million decrease in generation revenues for the pre-merger companies in 2012 compared to 2011:

Source of Change in Generation Revenues	Decrease
	(In millions)
Retail:	
Effect of decrease in sales volumes	$ (587)
Change in prices	(139)
	(726)
Wholesale:	
Effect of decrease in sales volumes	(120)
Change in prices	(51)
	(171)
Decrease in Generation Revenues	$ (897)

The decrease in retail generation sales volume was primarily due to increased customer shopping in the Utilities' service territories in 2012, compared with 2011. This increased customer shopping, which does not impact earnings for the Regulated Distribution segment, is expected to continue. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 79% from 76% for the Ohio Companies, 64% from 52% for ME's, PN's and Penn's service areas and 50% from 44% for JCP&L. The decrease in retail generation prices resulted from the impact of lower auction prices on power supply prices in 2012 compared to 2011, partially offset by a full year of Ohio's RER Rider (recovers deferred costs relating to electric heating discounts).

The decrease in wholesale generation revenues of $171 million in 2012 resulted from the expiration and termination of NUG contracts in August 2011 and April 2012, lower capacity revenues and lower PJM market prices.

Transmission revenues increased $81 million primarily due to the implementation of Ohio's NMB transmission rider in June of 2011, which recovers network integration transmission service costs as describer further below.

The Allegheny companies added $157 million to revenues in 2012, including $136 million for distribution services and $43 million from generation sales, partially offset by a decrease of $19 million of transmission revenues and $3 million of other revenues.

Operating Expenses —

Total operating expenses decreased by $936 million in 2012. Excluding the Allegheny Utilities, total operating expenses decreased by $897 million due to the following:

- Purchased power costs, excluding the Allegheny Utilities, were $890 million lower in 2012 primarily due to a decrease in volumes required from increased customer shopping, the impact of milder weather and lower unit power supply costs during 2012 compared to 2011 as a result of lower auction prices.

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (149)
Change due to decreased volumes	(490)
	(639)
Purchases from affiliates:	
Change due to decreased unit costs	(65)
Change due to decreased volumes	(257)
	(322)
Decrease in costs deferred	71
Decrease in Purchased Power Costs	$ (890)

- Transmission expenses increased $115 million during 2012 compared to 2011. The increase is primarily due to network integration transmission service expenses that, prior to June 2011, were incurred by the generation supplier, and are now being recovered through the NMB transmission rider referred to above.
- Other operation and maintenance expenses increased $197 million primarily due to higher labor, professional contractor and material costs to repair storm-related damage.
- Energy Efficiency program costs, which are recovered through rates, increased by $16 million.
- Other costs decreased due to the absence of a provision for excess and obsolete material of $13 million that was recognized in 2011 relating to revised inventory practices adopted in conjunction with the Allegheny merger.
- Merger-related costs decreased $60 million in 2012 compared to 2011.
- Pension and OPEB mark-to-market charges increased $87 million, reflecting lower discount rates to measure related obligations in 2012.
- Depreciation expense increased by $27 million due to a higher asset base.
- Deferral of storm costs increased by $186 million primarily related to storm restoration expenses associated with Hurricane Sandy and the "derecho" wind storm.
- Net regulatory asset amortization decreased $162 million primarily due to the scheduled suspension of the Ohio rider recovering deferred distribution costs in December 2011 and the rate reduction for JCP&L's NUG deferred cost recovery in March of 2012, partially offset by the recovery in Ohio of residential generation credits for electric heating discounts, which began in September 2011.
- General taxes decreased by $28 million primarily due to a decrease in revenue-related taxes.

Operating expenses for the Allegheny Utilities are summarized in the following table:

	For the Years Ended December 31,		Increase
Operating Expenses - Allegheny[1]	**2012**	**2011**	**(Decrease)**
	(In millions)		
Purchased Power	$ 1,170	$ 1,146	$ 24
Fuel	263	268	(5)
Transmission	180	184	(4)
Deferral of storm costs	(49)	(10)	(39)
Amortization of other regulatory assets, net	(14)	(13)	(1)
Pensions and OPEB mark-to-market adjustment	91	76	15
Other operating expenses	273	240	33
General taxes	130	113	17
Depreciation	152	144	8
Impairment of long-lived assets[2]	—	87	(87)
Total Operating Expenses	$ 2,196	$ 2,235	$ (39)

(1) Allegheny results include 12 months in 2012 and 10 months in 2011.
(2) Deactivation of three regulated coal-fired fossil generating plants in West Virginia.

Other Expense —

Other expense increased $23 million in 2012 primarily due to higher interest expense on debt of the Allegheny Utilities and lower investment income on OE's and TE's NDT assets and the PNBV and Shippingport trusts.

Regulated Transmission — 2012 Compared with 2011

Net income increased by $32 million in 2012 compared to 2011 primarily due to two additional months of earnings in 2012 associated with TrAIL, PATH, and the Allegheny Utilities' transmission assets that were acquired in the merger.

Revenues —

Total revenues increased by $80 million principally due to revenues from TrAIL, PATH and the Allegheny Utilities' transmission assets in 2012 compared to 2011.

Revenues by transmission asset owner are shown in the following table:

Revenues by Transmission Asset Owner	For the Years Ended December 31, 2012	2011	Increase
		(In millions)	
ATSI	$ 213	$ 207	$ 6
TrAIL[(1)]	200	170	30
PATH[(1)]	18	14	4
Utilities[(1)]	309	269	40
Total Revenues	$ 740	$ 660	$ 80

(1) Allegheny results include 12 months in 2012 and 10 months in 2011.

Operating Expenses —

Total operating expenses increased by $28 million principally due to the addition of TrAIL, PATH and the Allegheny Utilities' transmission operating expenses for twelve months in 2012 compared to ten months in 2011, partially offset by reduced regulatory asset amortization due to the completion in May 2011 of ATSI's deferred vegetation management cost recovery.

Other Expense —

Other expense increased by $1 million due to twelve months of TrAIL interest expense in 2012 compared to ten months in 2011.

Competitive Energy Services — 2012 Compared with 2011

Net income decreased by $162 million in 2012, compared to 2011. The decrease in net income was primarily due to a $569 million gain ($358 million net of tax) on the partial sale of FEV's interest in Signal Peak in 2011 partially offset by 2011 impairment charges of $315 million primarily resulting from the decision to deactivate six older coal-fired generating plants. In addition, higher operating expenses were partially offset by increased direct and governmental aggregation sales and the inclusion of two additional months of earnings from the Allegheny companies in 2012.

Results of operations for the year ended December 31, 2011, include only ten months of Allegheny results which have been segregated from the pre-merger companies (FirstEnergy and its subsidiaries prior to the merger) for reporting and analysis.

Revenues —

Total revenues decreased by $376 million in 2012, compared to 2011, primarily due to a decline in POLR and structured sales and the sale of RECs. Revenues were also adversely impacted by lower unit prices compared to 2011.These decreases were partially offset by growth in direct, governmental aggregation and mass market sales and the inclusion of the Allegheny companies for twelve months in 2012 compared to ten months in 2011.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Years Ended December 31, 2012	2011	Increase (Decrease)
		(In millions)	
Pre-merger Companies:			
Direct	$ 2,849	$ 2,624	$ 225
Governmental Aggregation	1,029	1,032	(3)
Mass Market	352	129	223
POLR and Structured	899	944	(45)
Wholesale[1]	516	435	81
Transmission	116	106	10
RECs	7	67	(60)
Other	145	173	(28)
Allegheny companies[2]	1,607	1,627	(20)
Intra-segment eliminations[3]	(876)	(117)	(759)
Total Revenues	$ 6,644	$ 7,020	$ (376)
Allegheny companies[2]			
Direct	$ 85	$ 84	$ 1
POLR and Structured	366	561	(195)
Wholesale[1]	1,110	900	210
Transmission	45	88	(43)
Other	1	(6)	7
Total Revenues	$ 1,607	$ 1,627	$ (20)

(1) Excludes wholesale revenues classified in Discontinued Operations.

(2) Allegheny results include 12 months in 2012 and 10 months in 2011.

(3) Intra-segment eliminations represent the impact of wholesale netting transactions for FES and AE Supply on an hourly basis, and the elimination of intra-segment sales between the companies.

MWH Sales by Channel	For the Years Ended December 31, 2012	2011	Increase (Decrease)
	(In thousands)		
Pre-merger Companies:			
Direct	53,099	46,187	15.0 %
Governmental Aggregation	17,287	15,786	9.5 %
Mass Market	5,212	1,936	169.2 %
POLR and Structured	16,212	15,340	5.7 %
Wholesale[1]	96	2,916	(96.7)%
Allegheny companies[2]	29,697	26,379	12.6 %
Intra-segment eliminations	(17,821)	(1,806)	886.8 %
Total MWH Sales	103,782	106,738	(2.8)%
Allegheny companies[2]			
Direct	1,429	1,390	2.8 %
POLR	5,874	7,974	(26.3)%
Structured	578	1,492	(61.3)%
Wholesale[1]	21,816	15,523	40.5 %
Total MWH Sales	29,697	26,379	12.6 %

[1] Excludes wholesale sales classified in Discontinued Operations.

[2] Allegheny results include 12 months in 2012 and 10 months in 2011.

The following tables summarize the price and volume factors contributing to changes in revenues (excluding the Allegheny companies):

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
		(In millions)			
Direct	$ 393	$ (168)	$ —	$ —	$ 225
Governmental Aggregation	98	(101)	—	—	(3)
Mass Market	219	4	—	—	223
POLR and Structured Sales	16	(61)	—	—	(45)
Wholesale[1]	(90)	(1)	276	(104)	81

[1] Excludes wholesale sales classified in Discontinued Operations.

The increase in Direct revenues of $225 million resulted from higher sales volumes due to the acquisition of new customers, partially offset by lower unit prices. The decrease in Governmental Aggregation of $3 million resulted from lower unit prices, partially offset from the acquisition of new customers primarily in Illinois. The increase in Mass Market of $223 million resulted from the acquisition of new customers primarily in Ohio and Pennsylvania, partially offset by lower unit prices. The Direct, Governmental Aggregation and Mass Market customer base increased to 2.6 million customers in December 2012 as compared to 1.8 million in December 2011.

The decrease in POLR and structured revenues of $45 million was due primarily to lower sales volumes at the Ohio Companies, ME, PN and other non-associated companies. Revenues were also adversely impacted by lower unit prices, which were partially offset by increased structured sales. The decline in POLR sales reflects a continued strategic focus on other sales channels.

Wholesale revenues increased $81 million due to increased gains of $276 million on financially settled contracts, partially offset by $91 million decrease in short-term (net hourly positions) transactions resulting primarily from reduced generation and a $104 million decrease in capacity revenues.

The Allegheny companies had a decrease in POLR and structured revenues of $195 million due to lower sales volumes at associated companies. The decline in POLR sales reflects a continued focus on other sales channels by this segment. Transmission revenues declined $43 million due primarily to lower congestion revenues, partially offset by an increase in wholesale revenues due to the intra-segment sale to FES.

Operating Expenses —

Total operating expenses decreased by $621 million in 2012. Excluding the Allegheny companies, total operating expenses decreased by $525 million in 2012 due to the following:

- Fuel costs increased $92 million primarily due to the absence of cash received in 2011 from the assignment of a substantially below-market, long-term fossil fuel contract to a third party ($123 million) and higher unit prices ($57 million), partially offset by lower volumes consumed ($88 million). Higher unit prices resulted primarily from a $50 million termination charge associated with the retirement of a coal contract that is no longer needed as a result of the plant deactivations. Volumes decreased as a result of the deactivation of fossil generating units, the temporary reduction in operations at the Sammis Plant in September 2012 and an increase in economic purchases of power.

- Purchased power costs decreased $26 million due to lower unit prices ($310 million) and reduced capacity expenses ($116 million), partially offset by higher volumes ($158 million) and losses on settled contract ($235 million). The increase in purchased power volumes primarily relates to the overall increase in direct and governmental aggregation sales volumes, economic purchases and lower generation resulting from the deactivation of fossil generating units and the temporary reduction in operations at Sammis.

- Fossil operating costs decreased by $38 million due primarily to lower contractor, materials and equipment costs resulting from a decrease in planned and unplanned generating unit outages.

- Nuclear operating costs decreased by $13 million due primarily to lower contractor, materials and equipment costs, which were partially offset by higher labor costs. In 2012, there were refueling outages at Davis-Besse and Beaver Valley Units 1 and 2. There were refueling outages at Perry and Beaver Valley Unit 2 during 2011. Total MW days were reduced slightly in 2012 compared to 2011.

- Transmission expenses decreased $74 million due primarily to lower congestion, network and line loss costs, partially offset by higher ancillary costs.

- General taxes increased by $8 million primarily due to an increase in revenue-related taxes, which were partially offset by lower taxes associated with a lower ownership percentage in Signal Peak and lower property taxes.

- Depreciation expense decreased $14 million primarily due to a lower asset base resulting from 2011 asset sales and impairments, combined with credits resulting from a settlement with the DOE regarding storage of spent nuclear fuel.

- Other operating expenses decreased by $145 million primarily due to favorable mark-to-market adjustments on commodity contract positions ($123 million), a $5 million decrease in pensions and OPEB mark-to-market adjustment charges from lower net actuarial losses, and the absence of 2011 expenses for a $54 million excess and obsolete inventory adjustment relating to revised inventory practices adopted in connection with the Allegheny merger. These decreases were partially offset by net increases in other expenses of $37 million associated with the absence of revenue related to coal sales due to a lower ownership percentage in Signal Peak, and labor and agent fees associated with the retail business.

- Impairments of long-lived assets decreased $315 million due to the decision to deactivate six unregulated, coal-fired generating plants in 2011.

The Allegheny companies' operations for twelve months in 2012 and ten months in 2011 added $1,486 million and $1,582 million to operating expenses, respectively, as shown in the following table:

Operating Expenses - Allegheny[1]	For the Years Ended December 31, 2012	2011	Increase (Decrease)
		(In millions)	
Fuel	$ 861	$ 794	$ 67
Purchased power	103	149	(46)
Fossil generation	149	148	1
Transmission	123	198	(75)
Other operating expenses	38	100	(62)
Pensions and OPEB mark-to-market adjustment	49	44	5
General taxes	41	39	2
Depreciation	122	110	12
Total Operating Expense	$ 1,486	$ 1,582	$ (96)

[1] Allegheny results include 12 months in 2012 and 10 months in 2011, and excludes items classified in Discontinued Operations.

Fuel expenses increased due to higher generation levels and fuel prices. The purchased power expense decreased due to lower volumes purchased and lower capacity expenses. Transmission expense declined as a result of lower congestion.

Other Expense —

Total other expense in 2012 increased $541 million compared to 2011 due to the absence of the gain on the partial sale of FEV's interest in Signal Peak in 2011 ($569 million), partially offset by reduced net interest expense ($18 million) from debt reductions in 2011 and higher investment income ($10 million) from the NDTs.

Other — 2012 Compared with 2011

Financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $37 million decrease in earnings available to FirstEnergy Corp. in 2012 compared to 2011. The decrease resulted primarily from lower other operating expenses ($95 million) due to lower merger-related costs. These benefits were offset by decreased investment income ($33 million), decreased income attributable to noncontrolling interest ($17 million) relating to Signal Peak, which was deconsolidated in the fourth quarter of 2011, and increased income tax expense ($83 million).

Regulatory Assets

Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent amounts that are expected to be credited to customers through future regulated rates or amounts collected from customers for costs not yet incurred. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions. The following table provides information about the composition of net regulatory assets as of December 31, 2013 and December 31, 2012, and the changes during the year ended December 31, 2013:

Regulatory Assets by Source	December 31, 2013	December 31, 2012	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 266	$ 293	$ (27)
Customer receivables for future income taxes	518	505	13
Nuclear decommissioning and spent fuel disposal costs	(198)	(219)	21
Asset removal costs	(362)	(372)	10
Deferred transmission costs	112	352	(240)
Deferred generation costs	346	379	(33)
Deferred distribution costs	194	231	(37)
Contract valuations	260	463	(203)
Storm-related costs	455	469	(14)
Other	263	229	34
Total	$ 1,854	$ 2,330	$ (476)

Regulatory assets that do not earn a current return totaled approximately $477 million as of December 31, 2013 primarily related to storm damage costs.

As of December 31, 2013 and December 31, 2012, FirstEnergy had approximately $440 million and $480 million, respectively, of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within Other noncurrent liabilities on the Consolidated Balance Sheets.

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy's business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. In addition to internal sources to fund liquidity and capital requirements for 2014 and beyond, FirstEnergy expects to rely on external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through the issuance of long-term debt and/or equity. FirstEnergy expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets.

As discussed in the Overview, FirstEnergy's 2013 financial plan also included a series of actions, including the net transfer of 1,476 MW between AE Supply and MP of the Harrison and Pleasants power plants, which closed on October 9, 2013, and the sale of 527 MWs of unregulated hydro assets which closed on February 12, 2014. Proceeds from Harrison and the hydro sale were used to reduce debt at the Competitive Energy Services segment and at FE.

On September 25, 2013, FE filed a registration statement with the SEC to register 4 million shares of common stock to be issued to registered shareholders and its employees and the employees of its subsidiaries under its Stock Investment Plan. In addition, during December 2013, FE began fulfilling certain share-based benefit plan obligations through the issuance of authorized but unissued common stock.

In January 2014, FirstEnergy's Board of Directors declared a revised quarterly dividend of $0.36 per share of outstanding common stock. The dividend is payable March 1, 2014, to shareholders of record at the close of business on February 7, 2014. This revised dividend equates to an indicated annual dividend of $1.44 per share, reduced from the $0.55 per share quarterly dividend ($2.20 per share annually) that FirstEnergy had paid since 2008.

Capital expenditures for 2014 are expected to be approximately $3.3 billion, an increase of $1 billion from 2013 primarily due to increased transmission investments. Over the next several years, these capital expenditures, including this transmission expansion program, are expected to be funded with a combination of debt, equity issuances through the stock investment and employee benefit plans, and the projected $320 million annually in cash preserved as a result of the dividend action taken in January 2014. The Utilities and FirstEnergy's competitive generation operations expect to fund their capital expenditures over the next several years through cash from operations, debt, and, depending on the operating company, equity contributions from FE. Additionally, FirstEnergy also expects to issue long-term debt at certain Utilities and certain other subsidiaries to refinance short-term and maturing debt in the ordinary course, subject to market and other conditions. These actions are expected to continue the focus, in 2014, of maintaining strong balance sheets at the Utilities and the Competitive Energy Services segment.

A material adverse change in operations, or in the availability of external financing sources, could impact FirstEnergy's liquidity position and ability to fund its capital requirements. To mitigate risk, FirstEnergy's business strategy stresses financial discipline and a strong focus on execution. Major elements include the expectation of: adequate cash from operations, operational excellence, business plan execution, well-positioned generation fleet, no speculative trading operations, appropriate long-term commodity hedging positions, manageable capital expenditure program, adequately funded pension plan, minimal near-term maturities of existing long-term debt and a commitment to our dividend.

As of December 31, 2013, FirstEnergy's net deficit in working capital (current assets less current liabilities) was due in large part to currently payable long-term debt and short-term borrowings. Currently payable long-term debt as of December 31, 2013, included the following:

Currently Payable Long-Term Debt	(In millions)
PCRBs supported by bank LOCs [1]	$ 809
FMBs	175
Unsecured notes	150
Unsecured PCRBs [1]	76
Collateralized lease obligation bonds	74
Sinking fund requirements	124
Other notes	7
	$ 1,415

(1) These PCRBs are classified as currently payable long-term debt because the applicable interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.

Short-Term Borrowings

FirstEnergy had $3,404 million and $1,969 million of short-term borrowings as of December 31, 2013 and December 31, 2012, respectively. FirstEnergy's available liquidity as of January 31, 2014, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	May 2018	$ 2,500	$ 224
FES / AE Supply	Revolving	May 2018	2,500	2,489
FET[2]	Revolving	May 2018	1,000	—
		Subtotal	$ 6,000	$ 2,713
		Cash	—	48
		Total	$ 6,000	$ 2,761

(1) FE and the Utilities.
(2) Includes FET, ATSI and TrAIL.

Revolving Credit Facilities

FirstEnergy, FES/AE Supply and FET Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities). The Facilities consist of a $2.5 billion aggregate FirstEnergy Facility, a $2.5 billion FES/AE Supply Facility and a $1.0 billion FET Facility, that are each available until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio (as defined under each of the Facilities, as amended) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

On May 8, 2013, FE, FES, AE Supply and FE's other borrowing subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. The FE Facility was amended to increase the lending banks' commitments under the facility by $500 million to a total of $2.5 billion and to increase the individual borrower sub-limits for FE by $500 million to a total of $2.5 billion and for JCP&L by $175 million to a total of $600 million.

On October 31, 2013, FE amended its existing $2.5 billion multi-year syndicated revolving credit facility to exclude certain after-tax, non-cash write-downs and non-cash charges of approximately $1.4 billion (primarily related to Pension and OPEB mark-to-market adjustments, impairment of long-lived assets and regulatory charges) from the debt to total capitalization ratio calculations incurred through September 30, 2013. Additionally, the amendment provides for a future allowance of approximately $1.35 billion for after-tax, non-cash write-downs and non-cash charges over the remaining life of the facility. Similarly, the FES/AE Supply $2.5 billion revolving credit facility was also amended to exclude certain similar after-tax, non-cash write-downs and non-cash charges of $785.7 million incurred through September 30, 2013 from the debt to total capitalization ratio calculations. As of December 31, 2013, the borrowers were in compliance with the applicable debt to total capitalization ratios under the respective Facilities.

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations, as of December 31, 2013:

Borrower	FirstEnergy Revolving Credit Facility Sub-Limit	FES/AE Supply Revolving Credit Facility Sub-Limit	FET Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations
		(In millions)		
FE	$ 2,500	$ —	$ —	$ — [1]
FES	—	1,500	—	— [2]
AE Supply	—	1,000	—	— [2]
FET	—	—	1,000	— [1]
OE	500	—	—	500 [3]
CEI	500	—	—	500 [3]
TE	500	—	—	500 [3]
JCP&L	600	—	—	850 [3]
ME	300	—	—	500 [3]
PN	300	—	—	300 [3]
WP	200	—	—	200 [3]
MP	150	—	—	500 [3]
PE	150	—	—	150 [3]
ATSI	—	—	100	500 [3]
Penn	50	—	—	50 [3]
TrAIL	—	—	200	400 [3]

(1) No limitations.
(2) No limitation based upon blanket financing authorization from the FERC under existing market-based rate tariffs.
(3) Includes amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility, $700 million of the FirstEnergy Facility and $225 million of the FET Facility, subject to each borrower's sub-limit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower's borrowing sub-limit.

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in "pricing grids," whereby the cost of funds borrowed under the Facilities is related to the credit ratings of the company borrowing the funds, other than the FET Facility, which is based on its subsidiaries' credit ratings. Additionally, borrowings under each of the Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million.

Term Loan

During December of 2013, FE entered into an agreement to extend and amend its $150 million term loan agreement with a maturity date of December 31, 2014. The maturity of the loan was extended to December 31, 2015 and the principal amount was increased to $200 million.

FirstEnergy Money Pools

FirstEnergy's utility operating subsidiary companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2013 was 0.67% per annum for the regulated companies' money pool and 1.34% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of December 31, 2013, FirstEnergy's currently payable long-term debt included approximately $809 million ($736 million applicable to FES) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

The LOCs for FirstEnergy's variable interest rate PCRBs outstanding as of December 31, 2013 were issued by the following banks:

Bank	Aggregate Amount[1]	Termination Date	Reimbursements of Draws Due
	(In millions)		
UBS	$ 268	April 2014	April 2014
CitiBank N.A.	164	June 2014	June 2014
Wells Fargo	151	March 2014	March 2014
The Bank of Nova Scotia	48	April 2014	April 2014
The Bank of Nova Scotia	82	April 2015	April 2015
The Bank of Nova Scotia	96	December 2015	December 2015
Total	$ 809		

(1) Excludes approximately $9 million of applicable interest coverage.

Long-Term Debt Capacity

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. The following table displays FE's and its subsidiaries' credit ratings as of December 31, 2013:

	Senior Secured			Senior Unsecured		
Issuer	**S&P**	**Moody's**	**Fitch**	**S&P**	**Moody's**	**Fitch**
FE	—	—	—	BB+	Baa3	BB+
FES	—	—	—	BBB-	Baa3	BB+
AE Supply	—	—	—	BBB-	Baa3	BB+
AGC	—	—	—	BBB-	Baa3	BBB
ATSI	—	—	—	BBB-	Baa2	BBB+
CEI	BBB+	Baa1	BBB	BBB-	Baa3	BBB-
JCP&L	—	—	—	BBB-	Baa2	BBB
ME	—	—	—	BBB-	Baa2	BBB+
MP	BBB+	Baa1	A-	—	—	—
OE	BBB+	A3	BBB+	BBB-	Baa2	BBB
PN	—	—	—	BBB-	Baa2	BBB
Penn	BBB+	A3	BBB+	—	—	—
PE	BBB+	Baa1	A-	—	—	—
TE	BBB	Baa1	BBB	—	—	—
TrAIL	—	—	—	BBB-	Baa1	BBB+
WP	BBB+	A3	A-	—	—	—

Debt capacity is subject to the consolidated debt to total capitalization limits in the Facilities previously discussed. As of December 31, 2013, FE and its subsidiaries could issue additional debt of approximately $5.3 billion and remain within the limitations of the financial covenants required by the Facilities (as amended). As of December 31, 2013, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $5.3 billion given FE's consolidated debt to total capitalization ratio under its Facility, as amended.

Changes in Cash Position

As of December 31, 2013, FirstEnergy had $218 million of cash and cash equivalents compared to $172 million of cash and cash equivalents as of December 31, 2012. As of December 31, 2013 and December 31, 2012, FirstEnergy had approximately $103 million and $62 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

FirstEnergy's consolidated net cash from operating activities was provided by its regulated distribution, regulated transmission and competitive energy services businesses (see Results of Operations above). Net cash provided from operating activities was $2,662 million during 2013, $2,320 million during 2012 and $3,063 million during 2011, as summarized in the following table:

	For the Years Ended December 31,		
Operating Cash Flows	**2013**	**2012**	**2011**
		(In millions)	
Net income	$ 392	$ 771	$ 869
Non-cash charges	2,635	2,058	2,306
Pension trust contributions	—	(600)	(372)
Working capital and other	(365)	91	260
	$ 2,662	$ 2,320	$ 3,063

The $342 million increase in cash from operations is primarily a result of a $600 million pension contribution in 2012 that did not occur in 2013. The increase was partially offset primarily as a result of payments in 2013 associated with 2012 storm restoration activities.

The $577 million increase in non-cash charges is primarily due to the following:

- $795 million increase from impairment of long-lived assets due to the Hatfield's Ferry and Mitchell plant deactivations as well as the West Virginia asset transfer.
- $132 million increase from the loss on debt redemptions associated with the completion of the FES/AE Supply tender offers and FES debt redemptions described below.
- $162 million increase from lower deferred purchased power and other costs primarily due to the expiration of certain NUG agreements.
- $50 million increase from higher deferred rents and market lease valuation as a result of increased net amortization of lease expense.
- $232 million increase in amortization of regulatory assets primarily due to a regulatory asset impairments associated with the recovery of marginal transmission losses at ME and PN ($254 million), recovery of RECs for the Ohio Companies' ($51 million), and the asset transfer between MP and AE Supply ($23 million) as well as higher default generation service cost recovery in Pennsylvania, partially offset by a reduction of NUG cost recovery at ME and PN and higher transmission cost deferrals in Ohio.
- $99 million increase due to net commodity derivative transactions.
- $404 million decrease in deferred income taxes and investment tax credits. Of the decrease, $156 million was the result of the reversal of deferred income tax liabilities associated with the impairment of Hatfield's Ferry and Mitchell.
- $375 million increase due to storm deferrals related to Hurricane Sandy in 2012.
- $865 million decrease due to Pensions and OPEB mark-to-market charges, reflecting a higher discount rate to measure related obligations in 2013.

The $456 million decrease in cash flows from working capital and other is primarily due to the following:

- $101 million decrease from increased customer receivables during 2013 primarily as a result of increased weather related usage as described in the Results of Operations above.
- $183 million of decreased asset removal costs charged to income primarily related to hurricane Sandy in 2012.
- $146 million increase from materials and supplies, primarily due to reduced fuel inventory resulting primarily from plant deactivations in 2013 and 2012.
- $125 million decrease from lower accounts payable balances at the end of 2013, primarily due to higher balances related to Hurricane Sandy in 2012, a portion of which was paid in 2013.
- $187 million decrease from make whole premiums paid on debt redemptions during 2013.
- $114 million decrease from increased prepaid taxes.
- $87 million increase from higher accrued taxes driven by the timing of state tax related liabilities.

Cash Flows From Financing Activities

In 2013, cash provided from financing activities was $477 million compared to $807 million of net cash provided from financing activities during 2012. The following table summarizes new debt financing (net of any discounts) and redemptions:

	For the Years Ended December 31,		
Securities Issued or Redeemed / Repaid	**2013**	**2012**	**2011**
		(In millions)	
New Issues			
PCRBs	$ —	$ 650	$ 272
Long-term revolving credit	—	—	70
Senior secured notes	445	—	—
FMBs	1,000	100	—
Unsecured Notes	2,300	—	262
	$ 3,745	$ 750	$ 604
Redemptions / Repayments			
PCRBs	$ (470)	$ (238)	$ (792)
Long-term revolving credit	(50)	—	(495)
Senior secured notes	(376)	(118)	(460)
FMBs	(420)	—	(15)
Unsecured notes	(2,284)	(584)	(147)
	$ (3,600)	$ (940)	$ (1,909)
Tender premiums paid on debt redemptions	$ (110)	$ —	$ —
Short-term borrowings, net	$ 1,435	$ 1,969	$ (700)

On March 5, 2013, FE issued in aggregate $1.5 billion of senior unsecured notes in two series: $650 million of 2.75% senior notes due March 15, 2018 and $850 million of 4.25% senior notes due March 15, 2023. The stated interest rates are subject to adjustments based upon changes in the credit ratings of FirstEnergy but will not decrease below the issued rates. The proceeds were used to repay short-term borrowings and to invest in the money pool for FES and AE Supply's use in funding a portion of their concurrent tender offers.

On March 28, 2013, pursuant to tender offers launched in February 2013, FES and AE Supply repurchased $369 million and $294 million, respectively, of outstanding senior notes with interest rates ranging from 5.75% to 6.8%. The $369 million of FES repurchases consisted of original maturities of $252 million due 2021 and $117 million due 2039. The $294 million of AE Supply repurchases consisted of original maturities of $194 million due 2019 and $100 million due 2039. FES and AE Supply paid $67 million and $43 million, respectively, in tender premiums to repurchase the tendered senior notes. FirstEnergy recorded a loss on debt redemption of $119 million (FES - $71 million), including such premiums and other related expenses. The tender premiums paid are included in cash flows from financing activities in the Consolidated Statement of Cash Flows.

In March 2013, ME issued $300 million of 3.50% senior unsecured notes due March 15, 2023. Proceeds from this offering were used to repay $150 million of ME 4.95% senior unsecured notes that matured in March 2013 and short-term borrowings.

On April 15, 2013, FES redeemed $400 million of its 4.80% senior notes due 2015 and recorded a loss on debt redemption of $32 million including $31 million of make-whole premiums paid. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

On June 3, 2013, FG exercised a mandatory put option and repurchased approximately $235 million of PCRBs due 2023, which FG is currently holding for remarketing subject to future market and other conditions.

During August, the Ohio Companies redeemed an additional $660 million of long-term debt with interest rates ranging from 5.65% to 7.25% and paid approximately $120 million of make-whole premiums which were deferred as a regulatory asset and will be amortized over the original life of the redeemed debt. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows. Additionally, during August, JCP&L issued $500 million of 4.7% unsecured notes due April 2024 and used the proceeds to pay down a portion of its short-term debt obligations.

As discussed in Note 8, Variable Interest Entities, in June 2013, the SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds with a weighted average coupon of 2.48% to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds were sold to a trust that concurrently sold a like aggregate amount of its pass through trust certificates to public investors. The proceeds were primarily used to redeem $410 million in existing taxable bonds of the Ohio Companies with a weighted average coupon of 5.71%, including $30 million of make-whole premiums. The securitization effectively allows for the recovery of the make-whole premiums and transactional costs through the imposition of non-bypassable phase-in recovery charges on retail electric customers of the Ohio Companies pursuant to Ohio law. The $410 million of redemption consisted of original maturities of $225 million due 2013, $150 million due 2015 and $35 million due 2020. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

On November 15, 2013, AE Supply optionally redeemed $235 million of its 7.00% PCRBs due July 15, 2039 at 100% of the principal amount in connection with the deactivation of operations at Hatfield's Ferry.

On November 27, 2013, MP issued $400 million of 4.10% FMBs due April 15, 2024 and $600 million of 5.40% FMBs due December 15, 2043. Proceeds from this offering were used by MP to: (i) repay at maturity $300 million of its FMBs, 7.95% Series due December 15, 2013; (ii) redeem $120 million of its FMBs, 6.70% Series due June 15, 2014; (iii) repay a $572.7 million short-term promissory note originally issued on October 9, 2013 to its affiliate, AE Supply in connection with MP’s acquisition of the remaining ownership of the Harrison Power Station; and (iv) for working capital needs and other general corporate purposes.

During December of 2013, FE entered into an agreement to extend and amend its $150 million term loan agreement with a maturity date of December 31, 2014. The maturity of the loan was extended to December 31, 2015 and the principal amount was increased to $200 million. On December 26, 2013, PN redeemed $150 million of its 5.13% Senior Notes due April 1,2014 and ME redeemed $100 million of its 4.88% Senior Notes due April 1, 2014.

Cash Flows From Investing Activities

Cash used for investing activities in 2013 principally represented cash used for property additions. The following table summarizes investing activities for 2013, 2012 and 2011:

	For the Years Ended December 31,		
Cash Used for Investing Activities	**2013**	**2012**	**2011**
		(In millions)	
Property Additions:			
Regulated distribution	$ 1,272	$ 1,074	$ 868
Regulated transmission	461	507	390
Competitive energy services	827	1,014	778
Other and reconciling adjustments	78	83	93
Nuclear fuel	250	286	149
Cash received from Allegheny merger	—	—	(590)
Proceeds from asset sales	(4)	(17)	(840)
Investments	72	(62)	42
Asset removal costs	146	229	114
Other	(9)	43	(48)
	$ 3,093	$ 3,157	$ 956

Net cash used for investing activities during 2013 decreased by $64 million compared to 2012. The decrease was principally due to a decrease in property additions of $40 million, lower asset removal costs and nuclear fuel, partially offset by an increase in net purchases of investment securities and lower cash investments.

In 2012, FG acquired certain equity and other lessor interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for approximately $262 million and in March of 2013, FG acquired the remaining interests for approximately $221 million. During 2013, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $23 million. Additionally, in February 2014, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million.

CONTRACTUAL OBLIGATIONS

As of December 31, 2013, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2014	2015-2016	2017-2018	Thereafter
			(In millions)		
Long-term debt[1]	$ 17,005	$ 1,376	$ 2,305	$ 3,094	$ 10,230
Short-term borrowings	3,404	3,404	—	—	—
Interest on long-term debt[2]	10,965	881	1,658	1,424	7,002
Operating leases[3]	2,422	202	405	251	1,564
Fuel and purchased power[4]	22,292	2,485	4,111	2,971	12,725
Capital expenditures	2,516	1,099	775	453	189
Pension funding	1,087	—	717	229	141
Other[5]	279	75	82	65	57
Total	$ 59,970	$ 9,522	$ 10,053	$ 8,487	$ 31,908

(1) Excludes unamortized discounts and premiums, fair value accounting adjustments and capital leases.
(2) Interest on variable-rate debt based on rates as of December 31, 2013.
(3) See Note 6, Leases, of the Combined Notes to Consolidated Financial Statements.
(4) Amounts under contract with fixed or minimum quantities based on estimated annual requirements.
(5) Includes amounts for capital leases (see Note 6, Leases, of the Combined Notes to Consolidated Financial Statements) and contingent tax liabilities (see Note 5, Taxes, of the Combined Notes to Consolidated Financial Statements).

Excluded from the data shown above are estimates for the cash outlays from power purchase contracts entered into by most of the Utilities and under which they procure the power supply necessary to provide generation service to their customers who do not choose an alternative supplier. Although actual amounts will be determined by future customer behavior and consumption levels, management currently estimates these cash outlays will be approximately $2.9 billion in 2014, $0.7 billion of which are expected to relate to the Utilities' contracts with FES.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. The maximum potential amount of future payments FirstEnergy could be required to make under these guarantees as of December 31, 2013, was approximately $4.3 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FirstEnergy Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts[1]	$ 269
LOC (long-term debt) - interest coverage[2]	5
OVEC obligations	300
Deferred compensation arrangements	478
Other[3]	323
	1,375
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts	66
LOC (long-term debt) - interest coverage[2]	3
FES' guarantee of NG's nuclear property insurance	88
FES' guarantee of FG's sale and leaseback obligations	2,030
Other	10
	2,197
Global Holding facility	350
Surety Bonds	264
LOCs[4]	128
	742
Total Guarantees and Other Assurances	$ 4,314

(1) Issued for open-ended terms, with a 10-day termination right by FirstEnergy.

(2) Reflects the interest coverage portion of LOCs issued in support of floating rate PCRBs with various maturities. The principal amount of floating-rate PCRBs of $809 million is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.

(3) Primarily includes guarantees of $125 million and $11 million for nuclear decommissioning funding assurances and $161 million supporting OE's sale and leaseback arrangement, and $20 million for railcar leases.

(4) Includes $7 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities, $96 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $25 million pledged in connection with the sale and leaseback of Perry by OE.

FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG, and NG would have claims against each of FES, FG, and NG, regardless of whether their primary obligor is FES, FG, or NG.

Collateral and Contingent-Related Features

In the normal course of business, FE and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuel, and emission allowances. Certain bilateral agreements and derivative instruments contain provisions that require FE or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FE's or its subsidiaries' credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. The incremental collateral requirement allows for the offsetting of assets and liabilities with the same counterparty, where the contractual right of offset exists under applicable master netting agreements.

Bilateral agreements and derivative instruments entered into by FE and its subsidiaries have margining provisions that require posting of collateral. Based on FES' power portfolio exposure as of December 31, 2013, FES has posted collateral of $142 million and AE supply has posted collateral of $8 million. The Regulated Distribution segment has posted collateral of $11 million.

These credit-risk-related contingent features stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a "material adverse event," the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of December 31, 2013:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 496	$ 6	$ 53	$ 555
BB+/Ba1 Credit Ratings	$ 542	$ 6	$ 53	$ 601
Full impact of credit contingent contractual obligations	$ 777	$ 58	$ 88	$ 923

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and Competitive Energy Services segment. As of December 31, 2013, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES and AE Supply would be required to post $66 million and $2 million, respectively.

Other Commitments and Contingencies

FirstEnergy is a guarantor under a syndicated three-year senior secured term loan facility due October 18, 2015, under which Global Holding borrowed $350 million. Proceeds from the loan were used to repay Signal Peak's and Global Rail's maturing $350 million syndicated two-year senior secured term loan facility. In addition to FirstEnergy, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, have also provided their joint and several guaranties of the obligations of Global Holding under the new facility.

In connection with the current facility, 69.99% of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with FEV's and WMB Marketing Ventures, LLC's respective 33-1/3% membership interests in Global Holding, are pledged to the lenders under the current facility as collateral.

FirstEnergy, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed to use their best efforts to refinance the new facility no later than July 20, 2015, which reflects the terms of an amendment dated August 14, 2013, on a non-recourse basis so that FirstEnergy's guaranty can be terminated and/or released. If that refinancing does not occur, FirstEnergy may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the new facility in full. In lieu of providing such funding, the co-owners, at FirstEnergy's option, may provide their several guaranties of Global Holding's obligations under the facility. FirstEnergy receives a fee for providing its guaranty, payable semiannually, which accrued at a rate of 4% through December 31, 2012, and accrues at a rate of 5% from January 1, 2013 through October 18, 2015, which amends the rate in the prior agreement, in each case based upon the average daily outstanding aggregate commitments under the facility for such semiannual period.

OFF-BALANCE SHEET ARRANGEMENTS

FES and certain of the Ohio Companies have obligations that are not included on their Consolidated Balance Sheets related to the Perry Unit 1, Beaver Valley Unit 2, and 2007 Bruce Mansfield Plant sale and leaseback arrangements, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, was approximately $1.1 billion as of December 31, 2013, of which approximately $1 billion relates to the 2007 Bruce Mansfield sale and leaseback arrangement expiring in 2040, and approximately $75 million relates to the Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback arrangements expiring in 2016 and 2017, respectively. From time to time FirstEnergy and these companies enter into discussions with certain parties to the arrangements regarding acquisition of owner participant and other interests. However, FirstEnergy cannot provide assurance that any such acquisitions will occur on satisfactory terms or at all.

During the second quarter of 2013, in connection with the Perry sale and leaseback arrangement, OE provided notice to return the leased interests in the plant to the owner participants (representing an aggregate of approximately 103 MWs of the 1,268 MWs of total capacity of the Perry Plant) at the expiration of the lease (May 2016) in lieu of extending the lease or buying the interest at the then appraised FMV. During 2013, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $23 million. Additionally, in February 2014, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million.

MARKET RISK INFORMATION

FirstEnergy uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. FirstEnergy’s Risk Policy Committee, comprised of members of senior management, provides general oversight for risk management activities throughout the company.

Commodity Price Risk

FirstEnergy is exposed to financial risks resulting from fluctuating commodity prices, including prices for electricity, natural gas, coal and energy transmission. FirstEnergy's Risk Management Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and

established risk management practice. FirstEnergy uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 9, Fair Value Measurements, of the Combined Notes to Consolidated Financial Statements). Sources of information for the valuation of net commodity derivative contracts assets and liabilities as of December 31, 2013 are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	2014	2015	2016	2017	2018	Thereafter	Total
				(In millions)			
Prices actively quoted[1]	$ (6)	$ —	$ —	$ —	$ —	$ —	$ (6)
Other external sources[2]	(12)	(32)	(21)	(10)	—	—	(75)
Prices based on models	(5)	—	1	1	(9)	(15)	(27)
Total[3]	$ (23)	$ (32)	$ (20)	$ (9)	$ (9)	$ (15)	$ (108)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.
(3) Includes $(202) million in non-hedge derivative contracts that are primarily related to NUG contracts. NUG contracts are generally subject to regulatory accounting and do not materially impact earnings.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. Based on derivative contracts held as of December 31, 2013, a 10% adverse change in commodity prices would decrease net income by approximately $27 million during the next 12 months.

Equity Price Risk

As of December 31, 2013, the FirstEnergy pension plan assets were approximately allocated as follows: 18% in equity securities, 40% in fixed income securities, 23% in absolute return strategies, 6% in real estate and 13% in cash and short-term securities. A decline in the value of pension plan assets could result in additional funding requirements. FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2013, FirstEnergy made no contributions to its qualified pension plans. See Note 3, Pensions and Other Postemployment Benefits, of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. In 2013, FirstEnergy's pension plan assets lost approximately (1.0)% as compared to an expected return on plan assets of 7.75%.

NDT funds have been established to satisfy NG's and other FirstEnergy subsidiaries' nuclear decommissioning obligations. As of December 31, 2013, approximately 77% of the funds were invested in fixed income securities, 15% of the funds were invested in equity securities and 8% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $1,695 million, $316 million and $179 million for fixed income securities, equity securities and short-term investments, respectively, as of December 31, 2013, excluding $11 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $32 million reduction in fair value as of December 31, 2013. Certain FirstEnergy subsidiaries recognize in earnings the unrealized losses on AFS securities held in its NDT as OTTI. A decline in the value of FirstEnergy's NDT or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During 2013, FirstEnergy contributed approximately $5 million to the NDT.

Interest Rate Risk

FirstEnergy's exposure to fluctuations in market interest rates is reduced since a significant portion of debt has fixed interest rates, as noted in the table below. FirstEnergy is subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 6, Leases of the Combined Notes to Consolidated Financial Statements, FirstEnergy's investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk.

Comparison of Carrying Value to Fair Value

Year of Maturity	2014	2015	2016	2017	2018	There-after	Total	Fair Value
				(In millions)				
Assets:								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ 16	$ 10	$ 5	$ 2		$ 1,914	$ 1,947	$ 1,949
Average interest rate	8.7%	8.8%	8.9%	8.8%		4.8%	4.9%	
Liabilities:								
Long-term Debt:								
Fixed rate	$ 566	$ 817	$ 668	$ 1,516	$ 679	$ 10,344	$ 14,590	$ 15,555
Average interest rate	4.9%	4.5%	5.5%	6.1%	6.8%	5.7%	5.7%	
Variable rate		$ 150			$ 656	$ 1,653	$ 2,459	$ 2,402
Average interest rate		1.7%			2.7%	2.2%	2.3%	

In 2013, in connection with certain debt redemptions, FirstEnergy recorded gains of approximately $17 million related to terminated interest rate swaps. In 2012, FirstEnergy terminated all forward starting swap agreements resulting in cash proceeds and a net gain, recorded as a reduction to interest expense, of approximately $6 million. As of December 31, 2013 and 2012, FirstEnergy had no forward starting swap agreements.

CREDIT RISK

Credit risk is defined as the risk that a counterparty to a transaction will be unable to fulfill its contractual obligations. FirstEnergy evaluates the credit standing of a prospective counterparty based on the prospective counterparty's financial condition. FirstEnergy may impose specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. FirstEnergy monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

Wholesale Credit Risk

FirstEnergy measures wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to, or due from, counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FirstEnergy has a legally enforceable right of offset. FirstEnergy monitors and manages the credit risk of wholesale marketing, risk management and energy transacting operations through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral and the use of master netting agreements. FirstEnergy's portfolio of energy contracts has a current weighted average risk rating for energy contract counterparties of BBB (S&P).

Retail Credit Risk

FirstEnergy's principal retail credit risk exposure relates to its competitive electricity activities, which serve residential, commercial and industrial companies. Retail credit risk results when customers default on contractual obligations or fail to pay for service rendered. This risk represents the loss that may be incurred due to the nonpayment of customer accounts receivable balances, as well as the loss from the resale of energy previously committed to serve customers.

Retail credit risk is managed through established credit approval policies, monitoring customer exposures and the use of credit mitigation measures such as deposits in the form of LOCs, cash or prepayment arrangements.

Retail credit quality is affected by the economy and the ability of customers to manage through unfavorable economic cycles and other market changes. If the business environment were to be negatively affected by changes in economic or other market conditions, FirstEnergy's retail credit risk may be adversely impacted.

OUTLOOK

STATE REGULATION

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES and AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES, AE Supply and their public utility affiliates. In addition, if FES, AE Supply or any of their subsidiaries were to engage in the construction of significant new generation facilities in any of those states, they would also be subject to state siting authority.

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to residential SOS for PE customers expired on December 31, 2012, by statute, service continues in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential SOS have also expired; however, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change. PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. PE's initial plan submitted in compliance with the statute was approved in 2009 and covered 2009-2011, the first three years of the statutory period. Expenditures were originally estimated to be approximately $101 million for the PE programs for the entire period of 2009-2015. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan for the second three year period, 2012-2014, that includes additional and improved programs. The 2012-2014 plan is expected to cost approximately $66 million out of the original $101 million estimate for the entire EmPOWER program. On December 22, 2011, the MDPSC issued an order approving PE's second plan with various modifications and follow-up assignments. PE continues to recover program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date such recovery has not been sought or obtained by PE.

Pursuant to a bill passed by the Maryland legislature in 2011, the MDPSC adopted rules, effective May 28, 2012, that create specific requirements related to a utility's obligation to address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. The MDPSC will be required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. The new rules set utility-specific SAIDI and SAIFI targets for 2012-2015; prescribe detailed tree-trimming requirements, outage restoration and downed wire response deadlines; and impose other reliability and customer satisfaction requirements. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately $106 million over the period 2012-2015. On April 1, 2013, the Maryland electric utilities, including PE, filed their first annual reports on compliance with the new rules. The MDPSC conducted a hearing on August 20, 2013 to discuss the reports, after which an order was issued on September 3, 2013, which accepted PE's filing and the operational changes proposed therein.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards which had become final on May 28, 2012; selective increased investment in system hardening; creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the utilities to submit several reports over a series of months, relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further requires the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE has responded to the requirements in the order consistent with the schedule set forth therein. PE's final filing on September 3, 2013, discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would expect to make approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. The MDPSC has ordered that certain reports of its Staff relating to these matters be provided by May 1, 2014, and otherwise has not issued a schedule for further proceedings in this matter.

NEW JERSEY

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, is intended for smaller commercial and residential customers.

All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On September 7, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. In its written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012. In the filing, JCP&L requested approval to increase its revenues by approximately $31.5 million and reserved the right to update the filing to include costs associated with the impact of Hurricane Sandy. The NJBPU transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ has been assigned. On February 22, 2013, JCP&L updated its filing to request recovery of $603 million of distribution-related Hurricane Sandy restoration costs, resulting in increasing the total revenues requested to approximately $112 million. On June 14, 2013, JCP&L further updated its filing to: 1) include the impact of a depreciation study which had been directed by the NJBPU; 2) remove costs associated with 2012 major storms, consistent with the NJBPU orders establishing a generic proceeding to review 2011 and 2012 major storm costs (discussed below); and 3) reflect other revisions to JCP&L's filing. That filing represented an increase of approximately $20.6 million over the revenues produced by existing base rates. Testimony has also been filed in the matter by the Division of Rate Counsel and several other intervening parties in opposition to the base rate increase JCP&L requested. Specifically, the testimony of the Division of Rate Counsel's witnesses recommended that revenues produced by JCP&L's base rates for electric service be reduced by approximately $202.8 million (such amount did not address the revenue requirements associated with major storm events of 2011 and 2012, which are subject to review in the generic proceeding). JCP&L filed rebuttal testimony in response to the testimony of other parties on August 7, 2013. Hearings in the rate case have concluded. In the initial briefs of the parties filed on January 27, 2014, the Division of Rate Counsel recommended that base rate revenues be reduced by $214.9 million while the NJBPU Staff recommended a $207.4 million reduction (such amounts do not address the revenue requirements associated with the major storm events of 2011 and 2012). Reply briefs were filed on February 24, 2014.

On March 20, 2013, the NJBPU ordered that a generic proceeding be established to investigate the prudence of costs incurred by all New Jersey utilities for service restoration efforts associated with the major storm events of 2011 and 2012. The Order provided that if any utility had already filed a proceeding for recovery of such storm costs, to the extent the amount of approved recovery had not yet been determined, the prudence of such costs would be reviewed in the generic proceeding. On May 31, 2013, the NJBPU clarified its earlier order to indicate that the 2011 major storm costs would be reviewed expeditiously in the generic proceeding with the goal of maintaining the base rate case schedule established by the ALJ where recovery of such costs would be addressed. The NJBPU further indicated in the May 31 clarification that it would review the 2012 major storm costs in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding. On June 21, 2013, consistent with NJBPU's orders, JCP&L filed the detailed report in support of recovery of major storm costs with the NJBPU. On November 15, 2013, the Division of Rate Counsel filed testimony recommending that approximately $15 million of JCP&L’s costs be disallowed for recovery. Evidentiary hearings in this proceeding were scheduled for January 2014 but were subsequently adjourned by the NJBPU before their commencement. On February 24, 2014, a Stipulation was filed with the NJBPU by JCP&L, the Division of Rate Counsel and NJBPU Staff which will allow recovery of $736 million of JCP&L’s $744 million of costs related to the significant weather events of 2011 and 2012. As a result, FirstEnergy recorded a regulatory asset impairment charge of approximately $8 million (pre-tax) as of December 31, 2013, included in Amortization of regulatory assets, net within the Consolidated Statements of Income. The agreement, upon which no other party took a position to oppose or support, is now pending before the NJBPU. Recovery of 2011 storm costs will be addressed in the pending base rate case; recovery of 2012 storm costs will be determined by the NJBPU.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held in September 2011 to solicit comments regarding the state of preparedness and responsiveness of New Jersey's EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 28, 2011 related to this inquiry. On December 14, 2011, the NJBPU Staff filed a report of its preliminary findings and recommendations with respect to the electric utility companies' planning and response to Hurricane Irene and the October 2011 snowstorm. The NJBPU selected a consultant to further review and evaluate the New Jersey EDCs' preparation and restoration efforts with respect to Hurricane Irene and the October 2011 snowstorm, and the consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. JCP&L submitted written comments on the report. On January 24, 2013, based upon recommendations in its consultant's report, the NJBPU ordered the New Jersey EDCs to take a number of specific actions to improve their preparedness and responses to major storms. The order includes specific deadlines for implementation of measures with respect to preparedness efforts, communications, restoration and response, post event and underlying infrastructure issues. On May 31, 2013, the NJBPU ordered that the New Jersey EDCs implement a series of new communications enhancements intended to develop more effective communications among EDCs, municipal officials, customers and the NJBPU during extreme weather events and other expected periods of extended service interruptions. The new requirements include making information regarding estimated times of restoration available on the EDC's web sites and through other technological expedients. JCP&L is implementing the required measures consistent with the schedule set out in the above NJBPU's orders.

OHIO

The Ohio Companies primarily operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include:

- Generation supplied through a CBP;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, which also applies to tranches assigned post-auction;
- A 6% generation discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- No increase in base distribution rates through May 31, 2014; and
- A new distribution rider, Rider DCR, to recover a return of, and on, capital investments in the delivery system.

The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI's integration into PJM for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain PJM proceedings. The Ohio Companies also agreed to establish a $12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012. Several parties timely filed applications for rehearing. The PUCO issued an Entry on Rehearing on January 30, 2013 denying all applications for rehearing. Notices of appeal to the Supreme Court of Ohio were filed by two parties in the case, Northeast Ohio Public Energy Council and the ELPC. While briefing has been completed, the matter has not yet been scheduled for oral argument.

As approved, the ESP 3 plan continues certain provisions from the current ESP including:

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the existing ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan provides additional provisions, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Under SB221, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. The Ohio Companies were also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018. On May 15, 2013, the Ohio Companies filed their 2012 Status Update Report in which they indicated compliance with 2012 statutory energy efficiency and peak demand reduction benchmarks.

In accordance with PUCO Rules and a PUCO directive, on July 31, 2012 the Ohio Companies filed their three-year portfolio plan for the period January 1, 2013 through December 31, 2015. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period, which is expected to be recovered in rates to the extent approved by the PUCO. Hearings were held with the PUCO in October 2012. On March 20, 2013, the PUCO approved the three-year portfolio plan for 2013-2015. Applications for rehearing were filed by the Ohio Companies and several other parties on April 19, 2013. The Ohio Companies filed their request for rehearing primarily to challenge the PUCO's decision to mandate that they offer planned energy efficiency resources into PJM's base residual auction. On May 15, 2013, the PUCO granted the applications for rehearing for the sole purpose of further consideration of the matter. On July 17, 2013, the PUCO denied the Ohio Companies' application for rehearing, in part, but authorized the Ohio Companies to receive 20% of any revenues obtained from bidding energy efficiency and demand response reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. On August 16, 2013, ELPC and OCC filed applications for rehearing under the basis that the PUCO's authorization for the Ohio Companies to share in the PJM revenues was unlawful. The PUCO granted rehearing on September 11, 2013 for the sole purpose of further consideration of the issue.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with and are not supported by statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss

the appeal. The Ohio Companies' response was filed on November 4, 2013. The motion is still pending and additional briefing has followed. The Ohio Companies filed their merit brief with the Supreme Court of Ohio on February 24, 2014.

SB221 requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2024. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet the renewable energy requirements established under SB221. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs and selected auditors to perform a financial and management audit. Final audit reports filed with the PUCO generally supported the Ohio Companies' approach to procurement of RECs, but also recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of in-state renewable obligations that the auditor characterized as excessive. Following the hearing, the PUCO issued an Opinion and Order on August 7, 2013 approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for part of the purchases arising from one auction and directing the Ohio Companies to credit non-shopping customers in the amount of $43.3 million, plus interest, and to file tariff schedules reflecting the refund and interest costs within 60 days following the issuance of a final appealable order on the basis that the Ohio Companies did not prove such purchases were prudent. The Ohio Companies, along with other parties, timely filed applications for rehearing on September 6, 2013. On December 18, 2013, the PUCO denied all of the applications for rehearing. Based on the PUCO ruling, a regulatory charge of approximately $51 million, including interest, was recorded in the fourth quarter of 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. On December 24, 2013, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio. On February 10, 2014, the Supreme Court of Ohio granted the Ohio Companies' motion for stay, which went into effect on February 14, 2014. On February 18, 2014, the Office of Consumers' Counsel and the Environmental Law and Policy Center also filed appeals of the PUCO's order.

In March 2012, the Ohio Companies conducted an RFP process to obtain SRECs to help meet the statutory benchmarks for 2012 and beyond. With the successful completion of this RFP, the Ohio Companies achieved their in-state solar compliance requirements for 2012. The Ohio Companies also held a short-term RFP process to obtain all state SRECs and both in-state and all state non-solar RECs to help meet the statutory benchmarks for 2012. The Ohio Companies recently reported that they met all of their annual renewable energy resource requirements for reporting year 2012. The Ohio Companies conducted an RFP in 2013 to cover their all-state SREC and their in-state and all-state REC compliance obligations.

The PUCO instituted a statewide investigation on December 12, 2012 to evaluate the vitality of the competitive retail electric service market in Ohio. The PUCO provided interested stakeholders the opportunity to comment on twenty-two questions. The questions posed are categorized as market design and corporate separation. The Ohio Companies timely filed their comments on March 1, 2013, and filed reply comments on April 5, 2013. On June 5, 2013, the PUCO requested additional comments and reply comments on the topics of market design and corporate separation, which the Ohio Companies timely filed on July 8, 2013 and July 22, 2013, respectively. The PUCO held a series of workshops throughout 2013, which included an en banc workshop on December 11, 2013. The PUCO Staff filed a report on January 16, 2014, which contained a limited discussion of the workshops and the PUCO Staff's recommendations. The Ohio Companies submitted comments on February 6, 2014 and Reply Comments on February 20, 2014.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2015, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through descending clock auctions, competitive requests for proposals and spot market purchases. On November 4, 2013, the Pennsylvania Companies filed a DSP that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2015 through May 31, 2017. The Pennsylvania Companies proposed programs call for quarterly descending clock auctions to procure 3, 12, 24, and 48-month energy contracts, as well as, one RFP seeking 2-year contracts to secure SRECs for ME, PN, and Penn. Hearings on the plans are scheduled to be held March 4-7, 2014. The Pennsylvania Companies expect a decision from the PPUC by August 4, 2014.

The PPUC entered an Order on March 3, 2010 that denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed ME and PN to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC. Pursuant to a plan approved by the PPUC, ME and PN refunded those amounts to customers over a 29-month period that began in January of 2011. On appeal, the Commonwealth Court affirmed the PPUC's Order to the extent that it holds that line loss costs are not transmission costs and, therefore, the approximately $254 million in marginal transmission losses and associated carrying charges for the period prior to January 1, 2011, are not recoverable under ME's and PN's TSC riders. The Pennsylvania Supreme Court denied ME's and PN's Petition for Allowance of Appeal and the Supreme Court of the United States denied ME's and PN's Petition for Writ of Certiorari. ME and PN also filed a complaint in the U.S. District Court for the Eastern District of Pennsylvania to obtain an order that would enjoin enforcement of the PPUC and Pennsylvania court orders under a theory of federal preemption on the question of retail rate recovery of the marginal transmission loss charges. On September 30, 2013, the U.S. District Court granted the PPUC's motion to dismiss. As a result of the U.S. District Court's September 30, 2013 decision, FirstEnergy recorded a regulatory asset impairment charge of approximately $254 million (pre-tax) in the quarter ended September 30, 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. The balance of marginal transmission losses was fully refunded to customers by the second quarter of 2013.

On October 29, 2013, ME and PN filed a Notice of Appeal of the U.S. District Court's decision to dismiss the complaint with the United States Court of Appeals for the Third Circuit. On December 30, 2013, ME and PN filed a brief with the Third Circuit that explained why it was legal error for the U.S. District Court to dismiss the complaint. The PPUC filed its brief on February 3, 2014, and ME and PN filed a reply brief on February 21, 2014. Oral argument has been scheduled for April 9, 2014.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan (EE&C Plan) by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 provides for potentially significant financial penalties to be assessed on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted a report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. ME, PN and Penn achieved the 2011 benchmarks; however WP did not. WP could be subject to a statutory penalty of between $1 and $20 million. On July 15, 2013, the Pennsylvania Companies filed their preliminary energy efficiency and demand reduction results for the period ending May 31, 2013, indicating that all Pennsylvania Companies are expected to meet their statutory obligations. On November 15, 2013, the Pennsylvania Companies submitted their energy efficiency and peak demand reduction report for the period ending May 31, 2013, in which they indicated that all of the Pennsylvania Companies met their statutory requirements.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 15, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator. Based upon information received, the PPUC has not included a peak demand reduction requirement in the Phase II plans. The Pennsylvania Companies filed their Phase II plans and supporting testimony in November 2012. On January 16, 2013, the Pennsylvania Companies reached a settlement with all but one party on all but one issue. The settlement provides for the Pennsylvania Companies to meet with interested parties to discuss ways to expand upon the EE&C programs and incorporate any such enhancements after the plans are approved, provided that these enhancements will not jeopardize the Pennsylvania Companies' compliance with their required targets or exceed the statutory spending caps. On February 6, 2013, the Pennsylvania Companies filed revised Phase II EE&C Plans to conform the plans to the terms of the settlement. Total costs of these plans are expected to be approximately $234 million. All such costs are expected to be recoverable through the Pennsylvania Companies reconcilable Phase II EE&C Plan C riders. The remaining issue, raised by a natural gas company, involved the recommendation that the Pennsylvania Companies include in their plans incentives for natural gas space and water heating appliances. On March 14, 2013, the PPUC approved the 2013-2016 EE&C plans of the Pennsylvania Companies, adopting the settlement, and rejecting the natural gas companies recommendations.

In addition, Act 129 required utilities to file a SMIP with the PPUC. On December 31, 2012, the Pennsylvania Companies filed their Smart Meter Deployment Plan. The Deployment Plan requests deployment of approximately 98.5% of the smart meters to be installed over the period 2013 to 2019, and the remaining meters in difficult to reach locations to be installed by 2022, with an estimated life cycle cost of about $1.25 billion. Such costs are expected to be recovered through the Pennsylvania Companies' PPUC-approved Riders SMT-C. Evidentiary hearings were held and briefs were submitted by the Pennsylvania Companies and the Office of Consumer Advocate. On November 8, 2013, the ALJ issued a Recommended Decision recommending that the Pennsylvania Companies' Deployment Plan be adopted with certain modifications, including, among other things, that the Pennsylvania Companies perform further benchmarking analyses on their costs and hire an independent consultant to perform further analyses on potential savings. On December 2, 2013, the Pennsylvania Companies submitted exceptions in which they challenged, among other things, certain recommendations in the ALJ's decision, and requested approval of a modification to the deployment schedule so as to allow the entire Penn smart meter system (170,000 meters) to be built by the end of 2015, instead of the original proposed installation of 60,000 meters by the end of 2016. The Office of Consumer Advocate took exception to one issue and both parties filed replies to exceptions on December 12, 2013. The case is now before the PPUC for consideration. A decision is expected during the first quarter of 2014.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions concerning retail markets in Pennsylvania to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A final order was issued on February 15, 2013, providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items. Subsequently, the PPUC established five workgroups and one comment proceeding in order to seek resolution of certain matters and to clarify certain obligations that arose from that order.

The PPUC issued a Proposed Rulemaking Order on August 25, 2011, which proposed a number of substantial modifications to the current Code of Conduct regulations that were promulgated to provide competitive safeguards to the competitive retail electricity market in Pennsylvania. The proposed changes include, but are not limited to: an EGS may not have the same or substantially similar name as the EDC or its corporate parent; EDCs and EGSs would not be permitted to share office space and would need to

occupy different buildings; EDCs and affiliated EGSs could not share employees or services, except certain corporate support, emergency, or tariff services (the definition of "corporate support services" excludes items such as information systems, electronic data interchange, strategic management and planning, regulatory services, legal services, or commodities that have been included in regulated rates at less than market value); and an EGS must enter into a trademark agreement with the EDC before using its trademark or service mark. The Proposed Rulemaking Order was published on February 11, 2012, and comments were filed by the Pennsylvania Companies and FES on March 27, 2012. If implemented these rules could require a significant change in the ways FES and the Pennsylvania Companies do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition. Pennsylvania's Independent Regulatory Review Commission subsequently issued comments on the proposed rulemaking on April 26, 2012, which called for the PPUC to further justify the need for the proposed revisions by citing a lack of evidence demonstrating a need for them. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement reached with the other parties and approved by the WVPSC in June 2010 that provided for:

- $40 million annualized base rate increases effective June 29, 2010;
- Deferral of February 2010 storm restoration expenses over a maximum five-year period;
- Additional $20 million annualized base rate increase effective in January 2011;
- Decrease of $20 million in ENEC rates effective January 2011, providing for deferral of related costs for later recovery in 2012; and
- Moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012 and two public input hearings have been held. The WVPSC issued an Order in this matter on January 23, 2013 closing the proceeding and directing electric utilities to file a vegetation management plan within six months and to propose a cost recovery mechanism. This Order also requires MP and PE to file a status report regarding improvements to their storm response procedures by the same date. On July 23, 2013, MP and PE filed their vegetation management plans, which provided for recovery of costs through a surcharge mechanism. A hearing was held on December 3, 2013, and briefing followed but the WVPSC has not yet issued an opinion in this matter.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE filed a Petition for approval of a Generation Resource Transaction with the WVPSC in November 2012 that proposed a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer involved MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. FERC authorized the transfers on April 23, 2013 and the financing on May 13, 2013. A Joint Settlement Agreement was filed by the majority of parties on August 21, 2013. On October 7, 2013, the WVPSC authorized the transaction, with certain conditions, and on October 9, 2013, the transaction closed resulting in MP recording a pre-tax impairment charge of approximately $322 million in the fourth quarter of 2013 to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. The charge is included in Impairment of long lived assets within the Consolidated Statement of Income. Concurrently, MP recognized a regulatory liability of approximately $23 million representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. The $1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately $527 million and a note payable to AE Supply of approximately $573 million. The note payable to AE Supply was paid in the fourth quarter of 2013. In accordance with the settlement, MP and PE will file a base rate case by April 30, 2014. On November 6, 2013, the WVCAG petitioned for appeal with the West Virginia Supreme Court. MP and PE filed their response to the WVCAG petition on December 27, 2013 and WVCAG filed its reply on January 16, 2014. Oral argument before the Supreme Court is scheduled for March 5, 2014.

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, ATSI and TrAIL. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such items are found, FirstEnergy

develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases “self-reporting” an item to RFC. Moreover, it is clear that the NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk power system could result in the imposition of financial penalties that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis - each customer in the zone would pay based on its total usage of energy within PJM. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit found that FERC had not supported a prior FERC decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on that finding, remanded the rate design issue to FERC. In an order dated January 21, 2010, FERC set this matter for a “paper hearing” and requested parties to submit written comments. FERC identified nine separate issues for comment and directed PJM to file the first round of comments. PJM filed certain studies with FERC on April 13, 2010, which demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain LSEs in PJM bearing the majority of the costs. FirstEnergy and a number of other utilities, industrial customers and state utility commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state utility commissions supported continued socialization of these costs on a load ratio share basis. On March 30, 2012, FERC issued an order on remand reaffirming its prior decision that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp (or socialized) rate based on the amount of load served in a transmission zone and concluding that such methodology is just and reasonable and not unduly discriminatory or preferential. On April 30, 2012, FirstEnergy requested rehearing of FERC's March 30, 2012 order and on March 22, 2013, FERC denied rehearing. On March 29, 2013, FirstEnergy filed its Petition for Review with the U.S. Court of Appeals for the Seventh Circuit, and the case subsequently was consolidated for briefing and disposition before that court. Briefing is complete, and the case will be scheduled for oral argument, with a decision currently expected in 2014.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the effective date of the compliance filing. On January 31, 2013, FERC conditionally accepted the hybrid method to be effective on February 1, 2013, subject to refund and to a future order on PJM's separate Order No. 1000 compliance filing. On March 22, 2013, FERC granted final acceptance of the hybrid method. Certain parties have sought rehearing of parts of FERC's March 22, 2013 order. These requests for rehearing are pending before FERC. On July 10, 2013, the PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between: (1) the PJM region and the NYISO region and; (2) the PJM region and the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the cost of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region. On the same date, also in response to Order No. 1000, the PJM transmission owners, including FirstEnergy, also submitted to FERC a filing stating that the cost allocation provisions for interregional transmission projects provided in the Joint Operating Agreement between PJM and MISO comply with the requirements of Order No. 1000. On December 30, 2013, FERC conditionally accepted the PJM/SERTP cross-border project cost allocation filing, subject to refund and future orders in PJM's and SERTP's related Order No. 1000 interregional compliance proceedings. The PJM/NYISO and PJM/MISO cross-border project cost allocation filings remain pending before FERC. On January 16, 2014, FERC issued an order regarding the effective date of PJM's separate Order No. 1000 compliance filing, noting that it would address the merits of the comments on and protests to that filing and related compliance filings in a future order.

Numerous parties, including ATSI, FES, TrAIL, OE, CEI, TE, Penn, JCP&L, ME, MP, PN, WP and PE, have sought judicial review of Order No. 1000 before the U.S. Court of Appeals for the D.C. Circuit. Briefing was completed in December 2013 and oral argument is scheduled for March 20, 2014.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone. While many of the matters involved with the move have been resolved, FERC denied recovery by means of ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis that demonstrates net benefits to customers from the move. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC to resolve the exit fee and transmission

cost allocation issues. However, FERC subsequently rejected that settlement stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. On October 21, 2013, FirstEnergy filed a request for rehearing of FERC's order.

Separately, the question of ATSI's responsibility of certain costs for the “Michigan Thumb” transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings in front of FERC and certain U.S. appellate courts. The MISO and its allied parties assert that the benefits to the ATSI zone for the Michigan Thumb project are roughly commensurate with the costs that MISO desires to charge to the ATSI zone, estimated to be as much as $16 million per year. ATSI has submitted evidence that the Michigan Thumb project provides no electric benefits to the ATSI zone and, on that basis, opposes the MISO’s efforts to impose these costs to the ATSI zone loads. The MISO and its allied parties also assert that certain language in the MISO Transmission Owners Agreement requires ATSI to pay these charges. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. While FERC proceedings regarding whether the MISO can charge ATSI for MVP costs remain pending, on February 24, 2014, the U.S. Supreme Court declined to hear appeals filed by FirstEnergy and other parties of the Seventh Circuit's June 2013 decision upholding FERC's acceptance of the MISO's generic MVP cost allocation proposal.

In the May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to transmission customers in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. ATSI subsequently filed a petition for review with the U.S. Court of Appeals for the D.C. Circuit. The case thereafter was briefed and oral arguments took place on December 11, 2013. A decision currently is expected in the second quarter of 2014.

The outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM cannot be predicted at this time.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the U.S. Court of Appeals for the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets, during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011, and affirmed the dismissal in June 2012. On June 20, 2012, the California Parties appealed FERC's decision back to the Ninth Circuit. Briefing was completed before the Ninth Circuit on October 23, 2013. The timing of further action by the Ninth Circuit is unknown.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed another complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General has appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

The PATH project was proposed to be comprised of a 765 kV transmission line from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland. PJM initially authorized construction of the PATH project in June 2007. On August 24, 2012, the PJM Board of Managers canceled the PATH project, which it had suspended in February 2011. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% return on equity adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement judge procedures and hearing if the parties do not agree to a settlement. The issues subject to settlement include the prudence of the costs, the base return on equity and the period of recovery. PATH-Allegheny and PATH-WV are currently engaged in settlement discussions with the other parties. Depending on the outcome of a possible settlement or hearing, if settlement is not achieved, PATH-Allegheny and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

PATH-Allegheny and PATH-WV have requested rehearing of FERC's denial of the 0.5% return on equity adder for RTO membership; that request for rehearing remains pending before FERC. In addition, FERC has consolidated for settlement judge procedures and

hearing purposes three formal challenges to the PATH formula rate annual updates submitted to FERC in June 2010, June 2011 and June 2012, with the September 28, 2012 filing for recovery of costs associated with the cancellation of the PATH project.

Hydroelectric Asset Sale

On September 4, 2013, certain of FirstEnergy's subsidiaries submitted filings with FERC for authorization to sell eleven hydroelectric power plant projects to subsidiaries of Harbor Hydro Holdings, LLC (Harbor Hydro), a subsidiary of LS Power Equity Partners II, LP (LS Power). The eleven hydroelectric projects are: the Seneca Pumped Storage Project, Allegheny Lock & Dam No. 5, Allegheny Lock & Dam No. 6, the Lake Lynn Project, the Millville Hydro Project, the Dam No. 4 Project, the Dam No. 5 Project, and four additional projects located in Shenandoah, Front Royal and Luray, Virginia. The eleven projects have a combined generating capacity of approximately 527 MW. On February 12, 2014, the sale of the hydroelectric power plants to LS Power closed for approximately $395 million. See Note 20, Discontinued Operations and Assets Held for Sale for additional information regarding the assets sold.

MISO Capacity Portability

On June 11, 2012, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FERC is responding to suggestions from MISO and the MISO stakeholders that PJM's rules regarding the criteria and qualifications for external generation capacity resources be changed to ease participation by resources that are located in MISO in PJM's RPM capacity auctions. FirstEnergy submitted comments and reply comments in August 2012. In the fall of 2012, FirstEnergy participated in certain stakeholder meetings to review various proposals advanced by MISO. Although none of MISO's proposals attracted significant stakeholder support, in January 2013, MISO filed a pleading with FERC that renewed many of the arguments advanced in prior MISO filings and asked FERC to take expedited action to address MISO's allegations. FirstEnergy and other parties subsequently submitted filings arguing that MISO's concerns largely are without foundation and suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. On April 2, 2013, FERC issued an order directing MISO and PJM to make presentations to FERC regarding ongoing regional efforts to address whether barriers to transfer capability exist between the MISO and PJM regions and the actions the FERC should take to address any such barriers. The RTOs presented their respective positions to FERC on June 20, 2013 and provided additional information regarding their stakeholder prioritization survey, in response to a FERC request on June 27, 2013. On September 26, 2013, the RTOs jointly submitted an informational filing providing a description of and schedule for their Joint and Common Market initiatives. On December 19, 2013, FERC issued an order directing that FERC staff are to attend the "joint and common market" stakeholder meetings for the purpose of monitoring progress on the initiatives described in the September 26, 2013 joint informational filing and establishing a new proceeding to reflect the broadened scope of issues contemplated by that filing and the RTOs' joint and common market initiatives. FERC has not acted on the presentations, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

MOPR Reform

On December 7, 2012, PJM filed amendments to its tariff to revise the MOPR used in the RPM. PJM revised the MOPR to add two broad, categorical exemptions, eliminate an existing exemption, and to limit the applicability of the MOPR to certain capacity resources. The filing also included related and conforming changes to the RPM posting requirements and to those provisions describing the role of the Independent Market Monitor for the PJM Region. On May 2, 2013, FERC issued an order in large part accepting PJM's proposed reform of the MOPR, including the proposed exemptions and applicability but also requiring PJM to commit to future review and, if necessary, additional revisions to the MOPR to accommodate changing market conditions. On June 3, 2013, FirstEnergy submitted a request for rehearing of FERC's May 2, 2013 order. In its rehearing request, FirstEnergy referenced the results of the May 2013 PJM RPM capacity auction, and publicly-available data about the reasons for the unexpectedly low "rest-of-RTO" clearing price of $59 per MW-day, as supporting its contention that the MOPR reform depressed prices as predicted in FirstEnergy's December 28, 2012 and January 25, 2013 comments. FirstEnergy's request for rehearing is pending before FERC.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and they operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM tariff, the funds that are set aside to pay FTRs can be diverted to other uses, resulting in "underfunding" of FTR payments. Since June of 2010, FES and AE Supply have lost more than $65.5 million in revenues that they otherwise would have received as FTR holders to hedge congestion costs. FES and AE Supply expect to continue to experience significant underfunding.

On December 28, 2011, FES and AE Supply filed a complaint with FERC for the purpose of modifying certain provisions in the PJM tariff to eliminate FTR underfunding. On March 2, 2012, FERC issued an order dismissing the complaint. In its order, FERC ruled that it was not appropriate to initiate action at that time because of the unknown root causes of FTR underfunding. FERC directed

PJM to convene stakeholder proceedings for the purpose of determining the root causes of the FTR underfunding. FERC went on to note that its dismissal of the complaint was without prejudice to FES and AE Supply or any other affected entity filing a complaint if the stakeholder proceedings proved unavailing. FES and AE Supply sought rehearing of FERC's order and, on July 19, 2012, FERC denied rehearing. In April, 2012, PJM issued a report on FTR underfunding. However, the PJM stakeholder process proved unavailing as the stakeholders were not willing to change the tariff to eliminate FTR underfunding. Accordingly, on February 15, 2013, FES and AE Supply refiled their complaint with FERC for the purpose of changing the PJM tariff to eliminate FTR underfunding. Various parties filed responsive pleadings, including PJM. On June 5, 2013, FERC issued its order denying the new complaint. On July 5, 2013, FirstEnergy filed a request for rehearing of FERC's order. FES and AE Supply's request for rehearing, and all subsequent filings in the docket, are pending before FERC.

PJM RPM Tariff Amendments

In November 2013, PJM began to submit a series of amendments to its RPM capacity tariff in order to address certain problems that have been observed in recent auctions. These problems can be grouped into three categories: (i) Demand Response (DR); (ii) imports; and (iii) modeling of transmission upgrades in calculating geographic clearing prices. The purpose of PJM's tariff amendments is to ensure that resources that clear in the RPM auctions are available and able to satisfy all obligations under the PJM tariffs. In each of the affected dockets, FirstEnergy submitted comments as part of a coalition of utilities (generally including an affiliate of AEP, Duke and Dayton). The FirstEnergy/coalition position was that all of the PJM proposals should be accepted as proposed, and that the FERC should order PJM to take additional steps that should have the effect of eliminating additional distortions and flaws in the RPM market. FERC issued deficiency letters requesting additional information from PJM regarding the imports and modeling filings, and on January 30, 2014 accepted the DR filing as proposed. On February 18 and 21, 2014, respectively, PJM filed its responses to FERC's deficiency letters regarding the modeling and imports filings. PJM's compliance filings and all other filings in the dockets are pending before FERC.

Market-Based Rate Authority, Triennial Update

OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP, PE, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC's requirements for holding market-based rate authority. On December 20, 2013, FESC submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. That filing is pending before FERC.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

CAA Compliance

FirstEnergy is required to meet federally-approved SO_2 and NOx emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a "safe, responsible, prudent and proper manner." One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued an NOV to GenOn Energy, Inc. alleging NSR violations at the Keystone, Portland and Shawville coal-fired plants based on "modifications" dating back to the mid-1980s. JCP&L, as the former owner of 16.67% of the Keystone Station, ME, as a former owner and operator of the Portland Station, and PN as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2011, the U.S. DOJ filed a complaint against PN in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against PN based on alleged "modifications" at the coal-fired Homer City generating plant during 1991 to 1994 without pre-construction NSR permitting in violation of the CAA's PSD and Title V permitting programs. The complaint was also filed against the former co-owner, NYSEG, and various current owners of Homer City, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In addition, the Commonwealth of Pennsylvania and the states of New Jersey and New York intervened and filed separate complaints regarding Homer City seeking injunctive relief and civil penalties.

In October 2011, the Court dismissed all of the claims with prejudice of the U.S. DOJ and the Commonwealth of Pennsylvania and the states of New Jersey and New York against all of the defendants, including PN. In December 2011, the U.S., the Commonwealth of Pennsylvania and the states of New Jersey and New York all filed notices appealing to the Third Circuit Court of Appeals which affirmed the dismissal on August 21, 2013 and then denied petitions for rehearing on December 12, 2013. PN believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International. PN is unable to predict the outcome of this matter or estimate the loss or possible range of loss.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations, at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. The EPA's NOV alleges equipment replacements during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically, opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. FG intends to comply with the CAA and Ohio regulations, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued additional CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. AE intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Allegheny Utilities in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that Allegheny performed major modifications in violation of the NSR provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. A non-jury trial on liability only was held in September 2010. On February 6, 2014, the Court entered judgment for AE, AE Supply, and the Allegheny Utilities finding they had not violated the CAA or the Pennsylvania Air Pollution Control Act. This decision does not change the status of these plants which remain deactivated.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the D.C. Circuit decided that CAIR violated the CAA but allowed CAIR to remain in effect to “temporarily preserve its environmental values” until the EPA replaces CAIR with a new rule consistent with the Court's decision. In July 2011, the EPA finalized CSAPR, to replace CAIR, requiring reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit and was ultimately vacated by the Court on August 21, 2012. The Court has ordered the EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. On January 24, 2013, EPA and intervenors' petitions seeking rehearing or rehearing en banc were denied by the U.S. Court of Appeals for the D.C. Circuit. On June 24, 2013, the Supreme Court of the United States agreed to review the decision vacating CSAPR and heard oral argument on December 10, 2013. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants stations. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield stations. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. MATS has been challenged in the U.S. Court of Appeals for the D.C. Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. Oral arguments were heard on December 10, 2013. Depending on the outcome

of these proceedings and how the MATS are ultimately implemented, FirstEnergy's total cost of compliance with MATS is currently estimated to be approximately $465 million (Competitive Energy Services segment of $240 million and Regulated Distribution segment of $225 million).

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island were deactivated. FG entered into RMR arrangements with PJM for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015, when they are scheduled to be deactivated. In February 2014, PJM notified FG that Eastlake Units 1-3 and Lake Shore Unit 18 will be released from RMR status as of September 15, 2014. As of October 9, 2013, the Hatfield's Ferry and Mitchell stations were also deactivated.

FirstEnergy and FES have various long-term coal transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. FE and FES have asserted force majeure defenses for delivery shortfalls under certain agreements, and are in discussion with the applicable counterparties. As to two agreements, FE and FES have settled monetary claims for damages for the failure to take minimum quantities for the calendar year 2012 by the payments of approximately $70 million, and agreed to pay liquidated damages for delivery shortfalls for 2013 and 2014. FE and FES recorded $67 million in liquidated damages in the fourth quarter of 2013, associated with estimated 2013 delivery shortfalls, which were paid in the first quarter of 2014. Additionally, in January 2014, FE and FES reached an agreement in principle with Mepco Holdings LLC to terminate a contract for future coal deliveries to Hatfield for $18 million, which was approved by the United States Bankruptcy Court on February 26, 2014. If FE and FES fail to reach a resolution with applicable counterparties for coal transportation agreements associated with the deactivated plants or unresolved aspects of the transportation agreements and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses do not excuse delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs to control emissions of certain GHGs. In his 2013 State of the Union address, President Obama called for Congressional action on GHG emissions indicating his administration will take action in the event Congress fails to act. In June 2013, the President's Climate Action Plan outlined Executive action to: (1) cut carbon pollution in America, including the EPA carbon pollution standards for both new and existing power plants by 17% by 2020 (from 2005 levels); (2) prepare the United States for the impacts of climate change; and (3) lead international efforts to combat global climate change and prepare for its impacts.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required the measurement and reporting of GHG emissions commencing in 2010. In December 2009, the EPA released its final “Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act.” The EPA's finding concludes that concentrations of several key GHGs increase the threat of climate change and may be regulated as “air pollutants” under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of CO_2 equivalents for existing facilities under the CAA's PSD program. On April 13, 2012, the EPA proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units that are larger than 25 MW, which were ultimately withdrawn. On June 25, 2013, a Presidential memorandum directed the EPA to complete, in a timely fashion, proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units, starting with re-proposal by September 20, 2013. The memorandum further directed the EPA to propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel generating units. On September 20, 2013, the EPA proposed a new source performance standard of 1,000 lbs. CO_2/MWH for large natural gas fired units (> 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for other natural gas fired units (≤ 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for fossil fuel fired units which would require partial carbon capture and storage. On October 15, 2013, the U.S. Supreme Court agreed to review a June 2012 D.C. Circuit Court of Appeals decision upholding the EPA's May 2010 regulations to decide a single narrow question: "Whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases?" Oral argument was held on February 24, 2014. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. A December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement that recognized the scientific view that the increase in global temperature should be below two degrees Celsius; includes a commitment by developed countries to provide funds, approaching $30 billion over three years with a goal of increasing to $100 billion by 2020; and establishes the “Green Climate Fund” to support mitigation, adaptation, and other climate-related activities in developing countries. To the extent that they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia and the United States, would commit to quantified economy-wide emissions targets by 2020, while developing countries, including

Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification. In December 2010, the U.N. Climate Change Conference in Cancun, Mexico resulted in an acknowledgment to reduce emissions from industrialized countries by 25 to 40 percent from 1990 emissions by 2020 and support enhanced action on climate change in the developing world. In December 2011 the U.N. Climate Change Conference in Durban, South Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the “Durban Platform for Enhanced Action”. This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020. In December 2012, the U.N. Climate Change Conference in Doha, Qatar, resulted in countries agreeing to a new commitment period under the Kyoto Protocol beginning in 2020. The new Doha Amendment to establish a second commitment period requires the ratification of three-quarters of the parties to the Kyoto Protocol before it becomes effective.

FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

In 2004, the EPA established new performance standards under Section 316(b) of the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). In 2007, the U.S. Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and the EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit's opinion and decided that Section 316(b) of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the CWA to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. The period for finalizing the Section 316(b) regulation was extended to April 17, 2014 under a Settlement Agreement between EPA and certain NGOs. FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant's water intake channel to divert fish away from the plant's water intake system. Depending on the results of such studies and the EPA's further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

On April 19, 2013, the EPA proposed regulatory changes to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423). The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the Agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by May 22, 2014, under a consent decree entered by a U.S. District Court and the treatment obligations are proposed to phase-in as waste water discharge permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule, the future costs of compliance with these standards may require material capital expenditures.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin Plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals or estimate the possible loss or range of loss.

In December 2010, PA DEP submitted its CWA 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. In May 2011, the EPA agreed with PA DEP's recommended sulfate impairment designation which requires the development of a TMDL limit for the river, a process that will take PA DEP approximately five years. Based on the stringency of the TMDL, MP may incur significant costs to reduce sulfate discharges into the Monongahela River if the NPDES permit for the coal-fired Fort Martin plant in West Virginia is required to be

modified or renewed to include more stringent effluent limitations for sulfate. However, the Hatfield's Ferry and Mitchell Plants in Pennsylvania that discharge into the Monongahela River were deactivated on October 9, 2013.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the possible loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2009, in an advance notice of public rulemaking, the EPA asserted that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of coal combustion residuals, including the option of regulation as a special waste under the EPA's hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of coal combustion residuals. On April 19, 2013, the EPA stated it would "align" its proposed coal combustion residuals regulations with revised waste water discharge effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) that were proposed on that date. On July 25, 2013, the House of Representatives passed H.R. 221 that would require CCRs to be regulated under Subtitle D of RCRA, as non-hazardous. On January 29, 2014, EPA agreed to take final action by December 19, 2014 on whether or not to pursue the proposed non-hazardous waste option for regulating CCRs in a Consent Decree to be filed in pending litigation. Depending on the content of the EPA's final effluent limitations rule, the specifics of any "alignment", whether EPA chooses to pursue the non-hazardous or hazardous waste option and the enactment of legislation, the future costs of compliance with such standards may require material capital expenditures.

On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified Consent Decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified Consent Decree also requires payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On February 1, 2013, FG submitted a Feasibility Study analyzing various technical issues relevant to the closure of LBR. On March 28, 2013, FG submitted to the PA DEP a Closure Plan Major Permit Modification Application which provides for placing a final cap over LBR that would require 15 years to fully implement following the closure of LBR. The estimated cost for the proposed closure plan is $234 million, including environmental and other post closure costs. On October 3, 2013, the PA DEP issued a technical deficiency letter citing four main deficiencies with the Closure Plan: (1) seeking to accelerate the 15 year period proposed by FG for closure activities to complete closure in 9 years by commencing closure activities prior to 2017 as proposed by FG; (2) seeking to extend bond closure and post closure activities beyond the 45 years proposed by FG; (3) seeking active dewatering of the CCBs in areas where there are seeps impacted by the Impoundment; and (4) seeking an abatement plan for groundwater impacted by arsenic. FG responded to the PA DEP on December 3, 2013, and as a result of the Closure Plan, FG increased its asset retirement obligation for LBR by $163 million in 2013. The Bruce Mansfield Plant is pursuing several options for its CCBs following December 31, 2016, and on January 23, 2013, announced a plan for beneficial use of its CCBs for mine reclamation in LaBelle, Pennsylvania. In June 2013, a complaint filed in the U.S. District Court for the Western District of Pennsylvania, alleges the LaBelle site is in violation of RCRA and state laws. In addition, on December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR.

On October 10, 2013 and December 5, 2013, complaints were filed on behalf of approximately 50 individuals against FE, FG and FES in the U.S. District Court for the Northern District of West Virginia and approximately 15 individuals against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages for alleged property damage, bodily injury and emotional distress related to the LBR CCB Impoundment. The complaints state claims for private nuisance, negligence, negligence per se, reckless conduct and trespass related to alleged groundwater contamination and odors emanating from the Impoundment. FE, FG and FES believe the claims are without merit and intend to vigorously defend themselves against the allegations made in the complaints, but, at this time, are unable to predict the outcome of the above matter or estimate the possible loss or range of loss.

FirstEnergy's future cost of compliance with any coal combustion residuals regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

Certain of FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2013 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $128 million have been accrued through December 31, 2013. Included in the total are accrued liabilities of approximately $82 million

for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2013, FirstEnergy had approximately $2.2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDT fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDT. FE maintains a $125 million parental guaranty relating to a potential shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry. FE also maintains an $11 million parental guaranty in support of the decommissioning of the spent fuel storage facilities located at its Davis-Besse and Perry nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranty, as appropriate.

On October 4, 2013, during a refueling outage for Beaver Valley Unit 1, FENOC conducted a planned visual examination of the interior containment liner and coatings. The containment design for Beaver Valley includes an interior steel liner that is surrounded by reinforced concrete. A penetration through the containment steel liner plate of approximately 0.4 inches by 0.28 inches was discovered. A detailed investigation was initiated, including laboratory analysis that has indicated that the degraded area was initiated by foreign material inadvertently left in the concrete during construction. An assessment has been performed which concluded that any postulated leakage through the affected area was within overall allowable limits for the containment building. The structural integrity of the containment building is not affected. Repair of the containment liner was completed and Unit 1 was returned to service on November 4, 2013.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. An NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. On July 9, 2012, the petitioners' proposed a contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding. In an order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance. The ASLB has suspended further consideration of the petitioners' proposed contention on the environmental impacts of spent fuel storage at Davis-Besse. The NRC Staff issued Waste Confidence Draft Generic Environmental Impact Statement and published a proposed rule on this subject in September of 2013. Other contentions proposed by the petitioners in this proceeding have been rejected by the ASLB. On February 18, 2014, Beyond Nuclear and Don't Waste Michigan, two of the petitioners in the Davis-Besse license renewal proceeding, requested that the NRC institute a rulemaking on the environmental impacts of high density spent fuel storage and mitigation alternatives. On February 27, 2014, these petitioners requested a suspension of the licensing decision in the Davis-Besse license renewal proceeding to allow the NRC to complete this rulemaking.

As part of routine inspections of the concrete shield building at Davis-Besse Nuclear Power Station in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. The shield building is a 2 1/2-foot thick reinforced concrete structure that provides biological shielding, protection from natural phenomena including wind and tornadoes and additional shielding in the event of an accident. FENOC then expanded its sample size to include all of the existing core bores in the shield building. These inspections, which are now complete, identified additional subsurface cracking that was determined to be pre-existing, but only now identified with the aid of improved inspection technology. These inspections also revealed that the cracking condition has propagated a small amount in select areas. Preliminary analysis of the inspections results confirm that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions.

On February 1, 2014, the Davis-Besse Nuclear Power Station entered into an outage to install two new steam generators, replace about a third of the unit’s 177 fuel assemblies and perform numerous safety inspections and preventative maintenance activities. During the preliminary stages of the outage an area of concrete that was not filled to the expected thickness within the shield building wall was discovered at the top of the temporary construction opening that was created as part of the 2011 outage. The 2011 temporary construction opening was created to install the new reactor head. FENOC has assessed the as-found condition of the concrete and has determined the shield building would have performed its design functions. This condition within the shield building wall will be repaired during this outage to conform to its original design configuration. This condition is not expected to extend the outage.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels

needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FENOC's nuclear facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal. Anker WV entered into a long term Coal Sales Agreement with AE Supply and MP for the supply of coal to the Harrison generating facility. Prior to the time of trial, ICG was dismissed as a defendant by the Court, which issue can be the subject of a future appeal. As a result of defendants' past and continued failure to supply the contracted coal, AE Supply and MP have incurred and will continue to incur significant additional costs for purchasing replacement coal. A non-jury trial was held from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they have incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. Defendants primarily claim that their performance is excused under a force majeure clause in the coal sales agreement and presented evidence at trial that they will continue to not provide the contracted yearly tonnage amounts. On May 2, 2011, the court entered a verdict in favor of AE Supply and MP for $104 million ($90 million in future damages and $14 million for replacement coal/interest). On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that the defendants still owed future damages, it remanded the calculation of those damages back to the trial court. The specific amount of those future damages is not known at this time, but they are expected to be calculated at a market price of coal that is significantly lower than the price used by the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on November 19, 2012. On July 2, 2013, the Petition for Allowance of Appeal was denied and in the second quarter of 2013 the now final past damage award of $15.5 million (including interest) was recognized. The case was sent back to the trial court to recalculate the future damages only and is currently in the discovery phase. A hearing is scheduled for May 13-14, 2014.

Other Legal Matters

In 2010, a lawsuit was filed in Allegheny County Court of Common Pleas by Michael Goretzka, for wrongful death and negligence after his wife was fatally electrocuted when she contacted a downed power line. The trial resulted in a verdict against WP and the parties settled this matter. WP's portion of the settlement was covered by insurance subject to the remainder of its deductible. On May 30, 2012, the PPUC's Bureau of Investigation and Enforcement (I&E) filed a Formal Complaint at the PPUC regarding this matter. On February 13, 2013, WP and I&E filed a Joint Petition for Full Settlement that includes, among other things, WP's agreement to conduct an infrared inspection of its primary distribution system, modify certain training programs, and pay an $86,000 civil penalty, which settlement is subject to PPUC approval. On August 29, 2013, the PPUC entered an Order granting the Goretzka family limited party status for the sole purpose of submitting comments to the settlement and issuing the settlement for comment by the parties. On September 16, 2013, the Goretzka family filed Limited Objections to the settlement. Reply comments were filed by WP on September 30, 2013. The PPUC entered an Opinion and Order on January 9, 2014 approving the Settlement with limited modifications regarding the frequency of refresher training and reporting obligations. WP filed a letter on January 17, 2014 accepting those modifications and noting its intent to begin implementation of the settlement terms.

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 15, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. In cases where FirstEnergy determines that it is not probable, but reasonably possible that it has a material obligation, it discloses such obligations and the possible loss or range of loss if such estimate can be made. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on any of the matters referenced above, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

FirstEnergy prepares consolidated financial statements in accordance with GAAP. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results. FirstEnergy's accounting policies require significant judgment regarding estimates and assumptions underlying the amounts included in the financial statements. Additional information regarding the application of accounting policies is included in the Combined Notes to Consolidated Financial Statements.

Revenue Recognition

FirstEnergy follows the accrual method of accounting for revenues, recognizing revenue for electricity that has been delivered to customers but not yet billed through the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis throughout the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for unbilled sales is recognized. The determination of unbilled sales and revenues requires management to make estimates regarding electricity available for retail load, transmission and distribution line losses, demand by customer class, applicable billing demands, weather-related impacts, number of days unbilled and tariff rates in effect within each customer class. See Note 1, Organization and Basis of Presentation for additional details.

Regulatory Accounting

FirstEnergy's regulated distribution and regulated transmission segments are subject to regulations that set the prices (rates) the Utilities, ATSI, TrAIL and PATH are permitted to charge customers based on costs that the regulatory agencies determine are permitted to be recovered. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This ratemaking process results in the recording of regulatory assets and liabilities based on anticipated future cash inflows and outflows. FirstEnergy regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future. See Note 15, Regulatory Matters for additional information.

Pensions and OPEB Accounting

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels.

FirstEnergy provides some non-contributory pre-retirement basic life insurance for employees who are eligible to retire. Health care benefits and/or subsidies to purchase health insurance, which include certain employee contributions, deductibles and co-payments, may also be available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

FirstEnergy's pensions and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2013, FirstEnergy did not make any contributions to its qualified pension plan. The underfunded status of FirstEnergy's qualified and non-qualified pension and OPEB plans as of December 31, 2013 was $2.5 billion.

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and OPEB obligations. The assumed discount rates for pensions were 5.00%, 4.25% and 5.00% as of December 31, 2013, 2012 and 2011, respectively. The assumed discount rates for OPEB were 4.75%, 4.00% and 4.75% as of December 31, 2013, 2012 and 2011, respectively.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the pension trusts. In 2013, FirstEnergy's qualified pensions and OPEB plan assets lost $(22) million or (0.3)% compared to amounts earned of $660 million, or 9.2% in 2012. The qualified pension and OPEB costs in 2013 and 2012 were computed using an assumed 7.75% rate of return for both years on plan assets which generated $535 million and $523 million of expected returns on plan assets, respectively. The expected return on pensions and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets will increase or decrease future net periodic pension and OPEB cost as the difference is recognized annually in the fourth quarter of each fiscal year or whenever a plan is determined to qualify for remeasurement.

Based on discount rates of 5.00% for pension, 4.75% for OPEB and an estimated return on assets of 7.75%, FirstEnergy expects its 2014 pre-tax net periodic postemployment benefit credits (including amounts capitalized) to be approximately $48 million (excluding any actuarial mark-to-market adjustments that would be recognized in 2014). The following table reflects the portion of pensions and OPEB costs that were charged to expense, including any pension and OPEB mark-to-market adjustments, in the three years ended December 31, 2013.

Postemployment Benefits Expense (Credits)	2013	2012	2011
		(In millions)	
Pensions	$ (134)	$ 596	$ 555
OPEB	(196)	(34)	(112)
Total	$ (330)	$ 562	$ 443

Health care cost trends continue to increase and will affect future OPEB costs. The 2013 composite health care trend rate assumptions were approximately 7.25-7.75%, compared to 7.5-8.0% in 2012, gradually decreasing to 5% in later years. In determining FirstEnergy's trend rate assumptions, included are the specific provisions of FirstEnergy's health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in FirstEnergy's health care plans, and projections of future medical trend rates. The effect on the pension and OPEB costs from changes in key assumptions are as follows:

Increase in Net Periodic Benefit Costs from Adverse Changes in Key Assumptions

Assumption	Adverse Change	Pensions	OPEB	Total
			(In millions)	
Discount rate	Decrease by .25%	250	19	$ 269
Long-term return on assets	Decrease by .25%	15	1	$ 16
Health care trend rate	Increase by 1.0%	N/A	24	$ 24

Please see Note 3, Pensions and Other Postemployment Benefits for additional information

Long-Lived Assets

FirstEnergy reviews long-lived assets, including regulatory assets, for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. See Note 11, Impairment of Long-Lived Assets for additional information.

Asset Retirement Obligations

FE recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FE's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FE uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset. ARO's as of December 31, 2013, are described further in Note 14, Asset Retirement Obligations.

Income Taxes

FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. We account for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being ultimately realized upon settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Company recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. See Note 5, Taxes for additional information.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. FirstEnergy evaluates goodwill for impairment annually on July 31 and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy first assesses qualitative factors to determine whether it is more likely than not (that is, likelihood of more than 50 percent) that the fair value of a reporting unit is less than its carrying value (including goodwill). If FirstEnergy concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then no further testing is required. However, if FirstEnergy concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying value, then the two-step goodwill impairment test is performed to identify a potential goodwill impairment and measure the amount of impairment to be recognized, if any.

FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission segments as of July 31, 2013, and determined the fair values of these segments were, more likely than not, greater than their carrying values. Due to excess generation supply in the region, which has caused a period of protracted low power and capacity prices impacting Competitive operations, FirstEnergy performed a quantitative assessment of the Competitive Energy Services segment as of July 31, 2013. The fair value of the Competitive Energy Services segment was calculated using a discounted cash flow analysis which was dependent on subjective factors determined by FirstEnergy management. Assumptions used in the analysis include discount rates, future power and natural gas prices, projected operating and capital cash flows and the fair value of debt. The estimated fair value of the Competitive Energy Services segment exceeded its carrying amount (including goodwill) as of July 31, 2013. Estimates of future cash flows are based upon relevant data at a point in time, which are subject to change and could vary from actual results. Continued weak economic conditions, lower than forecasted power and capacity prices, and revised environmental requirements could have a negative impact on future goodwill assessments.

See Note 1, Organization and Basis of Presentation for additional details.

NEW ACCOUNTING PRONOUNCEMENTS

New accounting pronouncements not yet effective are not expected to have a material effect on the financial statements of FE or its subsidiaries.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2013 consolidated financial statements as stated in their audit report included herein.

The Company's internal auditors, who are responsible to the Audit Committee of the Company's Board of Directors, review the results and performance of operating units within the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

The Company's Audit Committee consists of five independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2013.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control — Integrated Framework* published in 1992, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2013. The effectiveness of the Company's internal control over financial reporting, as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors of FirstEnergy Corp.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholders' equity, and cash flows, present fairly, in all material respects, the financial position of FirstEnergy Corp. and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework, published in 1992, by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 27, 2014

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

(In millions, except per share amounts)	For the Years Ended December 31, 2013	2012	2011
REVENUES:			
Electric utilities	$ 9,479	$ 9,800	$ 10,573
Unregulated businesses	5,438	5,473	5,532
Total revenues*	14,917	15,273	16,105
OPERATING EXPENSES:			
Fuel	2,496	2,471	2,317
Purchased power	3,963	4,246	4,874
Other operating expenses	3,593	3,760	3,949
Pensions and OPEB mark-to-market adjustment	(256)	609	507
Provision for depreciation	1,202	1,119	1,062
Deferral of storm costs	—	(375)	(145)
Amortization of regulatory assets, net	539	307	474
General taxes	978	984	977
Impairment of long-lived assets (Note 11)	795	—	413
Total operating expenses	13,310	13,121	14,428
OPERATING INCOME	1,607	2,152	1,677
OTHER INCOME (EXPENSE):			
Loss on debt redemptions	(132)	—	—
Gain on partial sale of Signal Peak	—	—	569
Investment income	36	77	114
Interest expense	(1,016)	(1,001)	(1,008)
Capitalized interest	75	72	70
Total other expense	(1,037)	(852)	(255)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	570	1,300	1,422
INCOME TAXES	195	545	566
INCOME FROM CONTINUING OPERATIONS	375	755	856
Discontinued operations (net of income taxes of $9, $8 and $8, respectively) (Note 20)	17	16	13
NET INCOME	392	771	869
Income (loss) attributable to noncontrolling interest	—	1	(16)
EARNINGS AVAILABLE TO FIRSTENERGY CORP.	$ 392	$ 770	$ 885
EARNINGS PER SHARE OF COMMON STOCK:			
Basic - Continuing Operations	$ 0.90	$ 1.81	$ 2.19
Basic - Discontinued Operations (Note 20)	0.04	0.04	0.03
Basic - Earnings Available to FirstEnergy Corp.	$ 0.94	$ 1.85	$ 2.22
Diluted - Continuing Operations	$ 0.90	$ 1.80	$ 2.18
Diluted - Discontinued Operations (Note 20)	0.04	0.04	0.03
Diluted - Earnings Available to FirstEnergy Corp.	$ 0.94	$ 1.84	$ 2.21
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:			
Basic	418	418	399
Diluted	419	419	401
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$ 1.65	$ 2.20	$ 2.20

* Includes excise tax collections of $458 million, $484 million and $511 million in 2013, 2012 and 2011, respectively.

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)	For the Years Ended December 31, 2013	2012	2011
NET INCOME	$ 392	$ 771	$ 869
OTHER COMPREHENSIVE INCOME (LOSS):			
Pensions and OPEB prior service costs	(160)	(115)	(90)
Amortized losses on derivative hedges	3	1	23
Change in unrealized gain on available-for-sale securities	(10)	(6)	19
Other comprehensive loss	(167)	(120)	(48)
Income tax benefits on other comprehensive loss	(66)	(79)	(49)
Other comprehensive income (loss), net of tax	(101)	(41)	1
COMPREHENSIVE INCOME	291	730	870
Comprehensive income (loss) attributable to noncontrolling interest	—	1	(16)
COMPREHENSIVE INCOME AVAILABLE TO FIRSTENERGY CORP.	$ 291	$ 729	$ 886

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS

(In millions, except share amounts)	December 31, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 218	$ 172
Receivables-		
Customers, net of allowance for uncollectible accounts of $52 in 2013 and $40 in 2012	1,720	1,614
Other, net of allowance for uncollectible accounts of $3 in 2013 and $4 in 2012	198	315
Materials and supplies, at average cost	752	861
Prepaid taxes	226	119
Derivatives	166	160
Accumulated deferred income taxes	366	319
Other	241	208
	3,887	3,768
PROPERTY, PLANT AND EQUIPMENT:		
In service	44,228	43,210
Less — Accumulated provision for depreciation	13,280	12,467
	30,948	30,743
Construction work in progress	2,304	2,293
	33,252	33,036
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,201	2,204
Investments in lease obligation bonds	33	54
Other	870	936
	3,104	3,194
ASSETS HELD FOR SALE (Note 20)	235	—
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,418	6,447
Regulatory assets	1,854	2,330
Other	1,674	1,719
	9,946	10,496
	$ 50,424	$ 50,494
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,415	$ 1,999
Short-term borrowings	3,404	1,969
Accounts payable	1,250	1,599
Accrued taxes	485	543
Accrued compensation and benefits	351	331
Derivatives	111	126
Other	621	1,038
	7,637	7,605
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 418,628,559 shares outstanding	42	42
Other paid-in capital	9,776	9,769
Accumulated other comprehensive income	284	385
Retained earnings	2,590	2,888
Total common stockholders' equity	12,692	13,084
Noncontrolling interest	3	9
Total equity	12,695	13,093
Long-term debt and other long-term obligations	15,831	15,179
	28,526	28,272
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	6,968	6,616
Retirement benefits	2,689	3,080
Asset retirement obligations	1,678	1,599
Deferred gain on sale and leaseback transaction	858	892
Adverse power contract liability	290	506
Other	1,778	1,924
	14,261	14,617
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 16)		
	$ 50,424	$ 50,494

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(In millions, except share amounts)	Common Stock		Other Paid-In Capital	Accumulated Other Comprehensive Income	Retained Earnings
	Number of Shares	Par Value			
Balance, January 1, 2011	304,835,407	$ 31	$ 5,444	$ 425	$ 3,084
Earnings available to FirstEnergy Corp.					885
Amortized losses on derivative hedges, net of $8 million of income taxes				15	
Change in unrealized gain on investments, net of $7 million of income taxes				12	
Pensions and OPEB, net of $64 million of income tax benefits (Note 3)				(26)	
Stock-based compensation			5		
Allegheny merger	113,381,030	11	4,316		
Cash dividends declared on common stock					(922)
Balance, December 31, 2011	418,216,437	42	9,765	426	3,047
Earnings available to FirstEnergy Corp.					770
Amortized losses on derivative hedges, net of $1 million of income tax benefits				2	
Change in unrealized gain on investments, net of $2 million of income tax benefits				(4)	
Pensions and OPEB, net of $76 million of income tax benefits (Note 3)				(39)	
Stock-based compensation			4		
Cash dividends declared on common stock					(920)
Equity method adjustment (Note 9)					(9)
Balance, December 31, 2012	418,216,437	42	9,769	385	2,888
Earnings available to FirstEnergy Corp.					392
Amortized losses on derivative hedges, net of $1 million of income taxes				2	
Change in unrealized gain on investments, net of $4 million of income tax benefits				(6)	
Pensions and OPEB, net of $63 million of income tax benefits (Note 3)				(97)	
Stock-based compensation			(4)		
Cash dividends declared on common stock					(690)
Stock issuance - employee benefits	412,122		11		
Balance, December 31, 2013	418,628,559	$ 42	$ 9,776	$ 284	$ 2,590

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	For the Years Ended December 31, 2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 392	$ 771	$ 869
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	1,202	1,119	1,062
Asset removal costs charged to income	20	203	55
Amortization of regulatory assets, net	539	307	474
Deferral of storm costs	—	(375)	(145)
Nuclear fuel amortization	209	210	201
Deferred purchased power and other costs	(76)	(238)	(278)
Deferred income taxes and investment tax credits, net	243	647	798
Impairments of long-lived assets	795	—	413
Investment impairments	90	27	19
Deferred rents and lease market valuation liability	(54)	(104)	(49)
Pensions and OPEB mark-to-market adjustment	(256)	609	507
Retirement benefits	(168)	(127)	(151)
Gain on asset sales	(21)	(17)	(545)
Commodity derivative transactions, net (Note 10)	4	(95)	(27)
Pension trust contributions	—	(600)	(372)
Cash collateral, net	(42)	16	(79)
Gain on sale of investment securities held in trusts, net	(56)	(71)	(59)
Loss on debt redemptions	132	—	—
Make-whole premiums paid on debt redemptions	(187)	—	—
Income from discontinued operations (Note 20)	(17)	(16)	(13)
Decrease (increase) in operating assets-			
Receivables	(114)	(13)	147
Materials and supplies	96	(50)	14
Prepayments and other current assets	(126)	(12)	101
Increase (decrease) in operating liabilities-			
Accounts payable	(25)	100	60
Accrued taxes	85	(2)	83
Accrued interest	(10)	(12)	(12)
Accrued compensation and benefits	19	(55)	69
Other	(12)	98	(79)
Net cash provided from operating activities	2,662	2,320	3,063
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	3,745	750	604
Short-term borrowings, net	1,435	1,969	—
Redemptions and Repayments-			
Long-term debt	(3,600)	(940)	(1,909)
Short-term borrowings, net	—	—	(700)
Tender premiums paid on debt redemptions	(110)	—	—
Common stock dividend payments	(920)	(920)	(881)
Other	(73)	(52)	(38)
Net cash provided from (used for) financing activities	477	807	(2,924)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(2,638)	(2,678)	(2,129)
Nuclear fuel	(250)	(286)	(149)
Proceeds from asset sales	4	17	840
Sales of investment securities held in trusts	2,047	2,980	4,207
Purchases of investment securities held in trusts	(2,096)	(3,020)	(4,309)
Cash investments	(23)	102	60
Cash received in Allegheny merger	—	—	590
Asset removal costs	(146)	(229)	(114)
Other	9	(43)	48
Net cash used for investing activities	(3,093)	(3,157)	(956)
Net change in cash and cash equivalents	46	(30)	(817)
Cash and cash equivalents at beginning of period	172	202	1,019
Cash and cash equivalents at end of period	$ 218	$ 172	$ 202
SUPPLEMENTAL CASH FLOW INFORMATION:			
Non-cash transaction: common stock issued in merger with Allegheny	$ —	$ —	$ 4,354
Cash paid (received) during the year -			
Interest (net of amounts capitalized)	$ 969	$ 962	$ 935
Income taxes	$ 36	$ (6)	$ (358)

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these financial statements.

FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

Unless otherwise indicated, defined terms and abbreviations used herein have the meanings set forth in the accompanying Glossary of Terms.

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. FirstEnergy's principal business is the holding, directly or indirectly, of all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FES and its principal subsidiaries (FG and NG), FESC and during 2013, AE and its principal subsidiaries (AE Supply, AGC, MP, PE, WP, FET and its principal subsidiaries (ATSI, TrAIL and PATH), and AESC). In addition, FirstEnergy holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., and GPU Nuclear, Inc. As of January 1, 2014, AE merged with and into FirstEnergy Corp., therefore, AE's direct subsidiaries, AE Supply, MP, PE, WP and FET, became direct subsidiaries of FirstEnergy Corp.

FirstEnergy follows GAAP and complies with the related regulations, orders, policies and practices prescribed by the SEC, FERC, and, as applicable, the PUCO, the PPUC, the MDPSC, the NYPSC, the WVPSC, the VSCC and the NJBPU. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not indicative of results of operations for any future period. FE and its subsidiaries have evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued.

FE and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation unless certain regulatory restrictions and rules apply. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary (see Note 8, Variable Interest Entities). Investments in affiliates over which FE and its subsidiaries have the ability to exercise significant influence, but with respect to which they are not the primary beneficiary and do not exercise control, follow the equity method of accounting. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity's earnings is reported in the Consolidated Statements of Income and Comprehensive Income. These Notes to the Consolidated Financial Statements are combined for FirstEnergy and FES.

Certain prior year amounts have been reclassified to conform to the current year presentation. These reclassifications include, but are not limited to, the classification of discontinued operations associated with our sale of hydro assets discussed in additional detail in Note 20, Discontinued Operations and Assets Held for Sale. Additionally, amounts collected in rates above actual charges related to asset removal have been reclassified as a regulatory liability which resulted in an increase to total assets and noncurrent liabilities of approximately $88 million.

ACCOUNTING FOR THE EFFECTS OF REGULATION

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to the Utilities, ATSI, PATH and TrAIL since their rates are established by a third-party regulator with the authority to set rates that bind customers, are cost-based and can be charged to and collected from customers.

FirstEnergy records regulatory assets and liabilities that result from the regulated rate-making process that would not be recorded under GAAP for non-regulated entities. These assets and liabilities are amortized in the Consolidated Statements of Income concurrent with the recovery or refund through customer rates. FirstEnergy believes that it is probable that its regulatory assets and liabilities will be recovered and settled, respectively, through future rates. FirstEnergy and the Utilities net their regulatory assets and liabilities based on federal and state jurisdictions.

The following table provides information about the composition of net regulatory assets as of December 31, 2013 and December 31, 2012, and the changes during the year ended December 31, 2013:

Regulatory Assets by Source	December 31, 2013	December 31, 2012	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 266	$ 293	$ (27)
Customer receivables for future income taxes	518	505	13
Nuclear decommissioning and spent fuel disposal costs	(198)	(219)	21
Asset removal costs	(362)	(372)	10
Deferred transmission costs	112	352	(240)
Deferred generation costs	346	379	(33)
Deferred distribution costs	194	231	(37)
Contract valuations	260	463	(203)
Storm-related costs	455	469	(14)
Other	263	229	34
Total	$ 1,854	$ 2,330	$ (476)

Regulatory assets that do not earn a current return totaled approximately $477 million as of December 31, 2013 primarily related to storm damage costs.

As of December 31, 2013 and December 31, 2012, FirstEnergy had approximately $440 million and $480 million, respectively, of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within Other noncurrent liabilities on the Consolidated Balance Sheets.

REVENUES AND RECEIVABLES

The Utilities' principal business is providing electric service to customers in Ohio, Pennsylvania, West Virginia, New Jersey and Maryland. FES' and AE Supply's principal business is supplying electric power to end-use customers through retail and wholesale arrangements, including affiliated company power sales to meet a portion of the POLR and default service requirements of the Ohio and Pennsylvania Companies and competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. Retail customers are metered on a cycle basis.

Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided from the last meter reading through the end of the month. This estimate includes many factors, among which are historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, the Utilities, FES and AE Supply accrue the estimated unbilled amount receivable as revenue and reverse the related prior period estimate.

Receivables from customers include retail electric sales and distribution deliveries to residential, commercial and industrial customers for the Utilities, and retail and wholesale sales to customers for FES and AE Supply. There was no material concentration of receivables as of December 31, 2013 and 2012 with respect to any particular segment of FirstEnergy's customers. Billed and unbilled customer receivables as of December 31, 2013 and 2012 are shown below.

Customer Receivables	FirstEnergy	FES
	(In millions)	
December 31, 2013		
Billed	$ 1,010	$ 301
Unbilled	710	238
Total	$ 1,720	$ 539
December 31, 2012		
Billed	$ 893	$ 243
Unbilled	721	240
Total	$ 1,614	$ 483

EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share of common stock are computed using the weighted average number of common shares outstanding during the relevant period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. The following table reconciles basic and diluted earnings per share of common stock:

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2013	2012	2011
	(In millions, except per share amounts)		
Income from continuing operations	$ 375	$ 755	$ 856
Less: Income attributable to noncontrolling interest	—	1	(16)
Income from continuing operations available to common shareholders	375	754	872
Discontinued operations (Note 20)	17	16	13
Earnings available to FirstEnergy Corp.	$ 392	$ 770	$ 885
Weighted average number of basic shares outstanding	418	418	399
Assumed exercise of dilutive stock options and awards[1]	1	1	2
Weighted average number of diluted shares outstanding	419	419	401
Earnings per share:			
Basic earnings per share:			
Continuing operations	$ 0.90	$ 1.81	$ 2.19
Discontinued operations (Note 20)	0.04	0.04	0.03
Net earnings per basic share	$ 0.94	$ 1.85	$ 2.22
Diluted earnings per share:			
Continuing operations	$ 0.90	$ 1.80	$ 2.18
Discontinued operations (Note 20)	0.04	0.04	0.03
Net earnings per diluted share	$ 0.94	$ 1.84	$ 2.21

(1) For the year ended December 31, 2013, 2 million shares were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive. The number of potentially dilutive securities not included in the calculation of diluted shares outstanding due to their antidilutive effect were not significant for the years ending December 31, 2012 or 2011.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (net of any impairments recognized), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy recognizes liabilities for planned major maintenance projects as they are incurred. The cost of nuclear fuel is capitalized within Property, plant and equipment and charged to fuel expense using the specific identification method. Net plant in service balances as of December 31, 2013 and 2012 were as follows:

	December 31, 2013			December 31, 2012		
Property, Plant and Equipment	In Service	Accum. Depr.	Net Plant	In Service	Accum. Depr.	Net Plant
			(In millions)			
Regulated Distribution	$ 23,098	$ (6,514)	$ 16,584	$ 21,473	$ (6,146)	$ 15,327
Regulated Transmission	5,564	(1,511)	4,053	5,078	(1,451)	3,627
Competitive	15,206	(5,088)	10,118	16,338	(4,739)	11,599
Other/Corporate	360	(167)	193	321	(131)	190
Total	$ 44,228	$ (13,280)	$ 30,948	$ 43,210	$ (12,467)	$ 30,743

FirstEnergy provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for FirstEnergy's and FES' electric plant in 2013, 2012 and 2011 are shown in the following table:

	Annual Composite Depreciation Rate		
	2013	2012	2011
FirstEnergy	2.6%	2.5%	2.4%
FES	3.1%	3.1%	3.1%

Jointly Owned Plants

FE, through its subsidiary, AGC, owns an undivided 40% interest (1,200 MWs) in a 3,000 MW pumped storage, hydroelectric station in Bath County, Virginia, operated by the 60% owner, Virginia Electric and Power Company, a non-affiliated utility. Net Property, Plant and Equipment includes $672 million, excluding $28 million of CWIP, representing AGC's share in this facility as of December 31, 2013. AGC is obligated to pay its share of the costs of this jointly-owned facility in the same proportion as its ownership interest using its own financing. AGC's share of direct expenses of the joint plant is included in FE's operating expenses on the Consolidated Statement of Income.

Asset Retirement Obligations

FE recognizes an ARO for the future decommissioning of its nuclear power plants and future remediation of other environmental liabilities associated with all of its long-lived assets. The ARO liability represents an estimate of the fair value of FE's current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FE uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plant's current license, settlement based on an extended license term and expected remediation dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related asset. AROs as of December 31, 2013, are described further in Note 14, Asset Retirement Obligations.

ASSET IMPAIRMENTS

Long-lived Assets

FirstEnergy reviews long-lived assets, including regulatory assets, for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, an impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. FirstEnergy utilizes the income approach, based upon discounted cash flows to estimate fair value. Impairments of long-lived assets recognized for the year ended December 31, 2013, are described further in Note 11, Impairment of Long-Lived Assets.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. FirstEnergy evaluates goodwill for impairment annually on July 31 and more frequently if indicators of impairment arise. In evaluating goodwill for impairment, FirstEnergy first assesses qualitative factors to determine whether it is more likely than not (that is, likelihood of more than 50 percent) that the fair value of a reporting unit is less than its carrying value (including goodwill). If FirstEnergy concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying value, then no further testing is required. However, if FirstEnergy concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying value, then the two-step goodwill impairment test is performed to identify a potential goodwill impairment and measure the amount of impairment to be recognized, if any.

FirstEnergy's reporting units are consistent with its reportable segments and consist of Regulated Distribution, Regulated Transmission, Competitive Energy Services and Other/Corporate. Goodwill is allocated to these reportable segments based on the original purchase price allocation of acquisitions. Total goodwill recognized by segment in FirstEnergy's Consolidated Balance Sheet is as follows:

Goodwill	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other/ Corporate	Consolidated
			(In millions)		
Balance as of December 31, 2012	$ 5,025	$ 526	$ 896	$ —	$ 6,447
Classification to Assets Held for Sale[(1)]	—	—	(29)	—	(29)
West Virginia asset transfer	67	—	(67)	—	—
Balance as of December 31, 2013	$ 5,092	$ 526	$ 800	$ —	$ 6,418

(1) See Note 20, Discontinued Operations and Assets Held for Sale.

As of December 31, 2013 and 2012, total goodwill recognized by FES was $23 million and $24 million, respectively. Neither FirstEnergy nor FES has accumulated impairment charges as of December 31, 2013.

Annual impairment testing is conducted as of July 31 of each year and for 2013, 2012 and 2011, the analysis indicated no impairment of goodwill. FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission segments as of July 31, 2013. FirstEnergy assessed economic, industry and market considerations in addition to overall financial performance of its Regulated Distribution and Regulated Transmission segments. It was determined that the fair values of these segments were, more likely than not, greater than their carrying values.

Due to excess generation supply in the region, which has caused a period of protracted low power and capacity prices impacting Competitive operations, FirstEnergy performed a quantitative assessment of the Competitive Energy Services segment as of July 31, 2013. The fair value of the Competitive Energy Services segment was calculated using a discounted cash flow analysis which included the effects of the potential sale of certain hydroelectric power stations and the West Virginia asset transfer. Assumptions used in the analysis include discount rates, market performance, projected operating and capital cash flows and the fair value of debt. The estimated fair value of the Competitive Energy Services segment exceeded its carrying amount (including goodwill) as of July 31, 2013. Continued weak economic conditions, lower than forecasted power and capacity prices, and revised environmental requirements could have a negative impact on future goodwill assessments.

In October of 2013, in connection with the closing of the West Virginia asset transfer, as discussed in Note 15, Regulatory Matters, FirstEnergy transferred approximately $67 million of goodwill, net from the Competitive Energy Services segment to the Regulated Distribution segment based on the relative fair value of the generating plants to the fair value of the respective segment.

Investments

At the end of each reporting period, FirstEnergy evaluates its investments for OTTI. Investments classified as AFS securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold an equity security until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FirstEnergy considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Unrealized gains and losses on AFS securities are recognized in AOCI. However, unrealized losses held in the NDTs of FES, OE and TE are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI. In 2013, 2012 and 2011, FirstEnergy recognized $90 million, $16 million and $19 million, respectively, of OTTI. During the same periods, FES recognized OTTI of $79 million, $14 million and $17 million, respectively. The fair values of FirstEnergy’s investments are disclosed in Note 9, Fair Value Measurements.

INVENTORY

Materials and supplies inventory includes fuel inventory and the distribution, transmission and generation plant materials, net of reserve for excess and obsolete inventory. Materials are generally charged to inventory at weighted average cost when purchased and expensed or capitalized, as appropriate, when used or installed. Fuel inventory is accounted for at weighted average cost when purchased, and recorded to fuel expense when consumed.

NEW ACCOUNTING PRONOUNCEMENTS

New accounting pronouncements not yet effective are not expected to have a material effect on the financial statements of FE or its subsidiaries.

2. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, for the years ended December 31, 2013, 2012 and 2011 for FirstEnergy and FES are shown in the following tables:

FirstEnergy

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
		(In millions)		
AOCI Balance, January 1, 2011	$ (54)	$ 7	$ 472	$ 425
Other comprehensive income (loss) before reclassifications	(9)	49	78	118
Amounts reclassified from AOCI	24	(37)	(104)	(117)
Net other comprehensive income (loss)	15	12	(26)	1
AOCI Balance, December 31, 2011	$ (39)	$ 19	$ 446	$ 426
Other comprehensive income before reclassifications	—	41	79	120
Amounts reclassified from AOCI	1	(45)	(117)	(161)
Net other comprehensive income (loss)	1	(4)	(38)	(41)
AOCI Balance, December 31, 2012	$ (38)	$ 15	$ 408	$ 385
Other comprehensive income before reclassifications	—	29	23	52
Amounts reclassified from AOCI	2	(35)	(120)	(153)
Net other comprehensive income (loss)	2	(6)	(97)	(101)
AOCI Balance, December 31, 2013	$ (36)	$ 9	$ 311	$ 284

FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
		(In millions)		
AOCI Balance, January 1, 2011	$ 1	$ 6	$ 55	$ 62
Other comprehensive income (loss) before reclassifications	(9)	42	8	41
Amounts reclassified from AOCI	16	(32)	(11)	(27)
Net other comprehensive income (loss)	7	10	(3)	14
AOCI Balance, December 31, 2011	$ 8	$ 16	$ 52	$ 76
Other comprehensive income before reclassifications	—	38	16	54
Amounts reclassified from AOCI	(5)	(41)	(12)	(58)
Net other comprehensive income (loss)	(5)	(3)	4	(4)
AOCI Balance, December 31, 2012	$ 3	$ 13	$ 56	$ 72
Other comprehensive income before reclassifications	—	26	3	29
Amounts reclassified from AOCI	(4)	(31)	(12)	(47)
Net other comprehensive loss	(4)	(5)	(9)	(18)
AOCI Balance, December 31, 2013	$ (1)	$ 8	$ 47	$ 54

The following amounts were reclassified from AOCI in the years ended December 31, 2013, 2012 and 2011 for FirstEnergy and FES are shown in the following tables:

FirstEnergy

Reclassifications from AOCI [2]	Year Ended December 31 2013	2012	2011	Affected Line Item in Consolidated Statements of Income
	(In millions)			
Gains & losses on cash flow hedges				
Commodity contracts	$ (8)	$ (9)	$ 26	Other operating expenses
Long-term debt	11	10	12	Interest expense
	3	1	38	Total before taxes
	(1)	—	(14)	Income tax benefits
	$ 2	$ 1	$ 24	Net of tax
Unrealized gains on AFS securities				
Realized gains on sales of securities	$ (56)	$ (72)	$ (59)	Investment income
	21	27	22	Income taxes
	$ (35)	$ (45)	$ (37)	Net of tax
Defined benefit pension and OPEB plans				
Prior-service costs	$ (195)	$ (191)	$ (169)	[1]
	75	74	65	Income taxes
	$ (120)	$ (117)	$ (104)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pensions and Other Postemployment Benefits for additional details.

[2] Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

FES

Reclassifications from AOCI [2]	Year Ended December 31 2013	2012	2011	Affected Line Item in Consolidated Statements of Income
	(In millions)			
Gains & losses on cash flow hedges				
Commodity contracts	$ (8)	$ (9)	$ 26	Other operating expenses
Long-term debt	2	—	1	Interest expense - other
	(6)	(9)	27	Total before taxes
	2	4	(11)	Income taxes (benefits)
	$ (4)	$ (5)	$ 16	Net of tax
Unrealized gains on AFS securities				
Realized gains on sales of securities	$ (49)	$ (65)	$ (51)	Investment income
	18	24	19	Income taxes
	$ (31)	$ (41)	$ (32)	Net of tax
Defined benefit pension and OPEB plans				
Prior-service costs	$ (20)	$ (20)	$ (18)	[1]
	8	8	7	Income taxes
	$ (12)	$ (12)	$ (11)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 3, Pensions and Other Postemployment Benefits for additional details.

[2] Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

3. PENSIONS AND OTHER POSTEMPLOYMENT BENEFITS

FirstEnergy provides noncontributory qualified defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. In addition, FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to certain employees, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing pensions and OPEB to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. FirstEnergy also has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits. On July 25, 2013, FirstEnergy announced that non-bargaining employees hired on or after January 1, 2014 will participate in a cash-balance defined benefit pension plan. The plan for existing employees will remain unchanged. Under the cash-balance pension plan, FirstEnergy will make contributions to eligible employee retirement accounts based on employee age and years of service. The balance of these accounts will be provided to employees when they leave the company.

FirstEnergy's pensions and OPEB funding policy is based on actuarial computations using the projected unit credit method. During the year ended December 31, 2013, FirstEnergy did not make any contributions to its qualified pension plan. Pension and OPEB costs are affected by employee demographics (including age, compensation levels and employment periods), the level of contributions made to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of the measurement date.

Obligations and Funded Status	Pensions		OPEB	
	2013	2012	2013	2012
		(In millions)		
Change in benefit obligation:				
Benefit obligation as of January 1	$ 8,975	$ 7,977	$ 1,076	$ 1,037
Service cost	197	161	13	12
Interest cost	372	389	37	47
Plan participants' contributions	—	—	15	17
Plan amendments	2	8	(37)	(85)
Medicare retiree drug subsidy	—	—	5	—
Actuarial (gain) loss	(846)	861	(107)	152
Benefits paid	(437)	(421)	(123)	(104)
Benefit obligation as of December 31	$ 8,263	$ 8,975	$ 879	$ 1,076
Change in fair value of plan assets:				
Fair value of plan assets as of January 1	$ 6,671	$ 5,867	$ 508	$ 528
Actual return on plan assets	(77)	611	56	48
Company contributions	14	614	39	19
Plan participants' contributions	—	—	15	17
Benefits paid	(437)	(421)	(123)	(104)
Fair value of plan assets as of December 31	$ 6,171	$ 6,671	$ 495	$ 508
Funded Status:				
Qualified plan	$ (1,782)	$ (1,967)		
Non-qualified plans	(310)	(336)		
Funded Status	$ (2,092)	$ (2,303)	$ (384)	$ (566)
Accumulated benefit obligation	$ 7,800	$ 8,355	$ —	$ —
Amounts Recognized on the Balance Sheet:				
Current liabilities	$ (15)	$ (14)	$ —	$ —
Noncurrent liabilities	(2,077)	(2,289)	(384)	(566)
Net liability as of December 31	$ (2,092)	$ (2,303)	$ (384)	$ (566)
Amounts Recognized in AOCI:				
Prior service cost (credit)	$ 48	$ 58	$ (558)	$ (728)
Assumptions Used to Determine Benefit Obligations (as of December 31)				
Discount rate	5.00%	4.25%	4.75%	4.00%
Rate of compensation increase	4.20%	4.70%	N/A	N/A
Assumed Health Care Cost Trend Rates (as of December 31)				
Health care cost trend rate assumed (pre/post-Medicare)	N/A	N/A	7.25-7.75%	7.5-8.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	N/A	N/A	5%	5%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	N/A	N/A	2020	2020
Allocation of Plan Assets (as of December 31)				
Equity securities	18%	15%	47%	39%
Bonds	40%	47%	40%	40%
Absolute return strategies	23%	22%	3%	4%
Real estate	6%	5%	1%	1%
Private equities	—%	1%	—%	—%
Cash and short-term securities	13%	10%	9%	16%
Total	100%	100%	100%	100%

The estimated 2014 amortization of pensions and OPEB prior service costs (credits) from AOCI into net periodic pensions and OPEB costs (credits) is approximately $8 million and $(176) million, respectively.

Components of Net Periodic Benefit Costs	Pensions			OPEB		
	2013	2012	2011	2013	2012	2011
			(In millions)			
Service cost	$ 197	$ 161	$ 130	$ 13	$ 12	$ 13
Interest cost	372	389	374	37	47	48
Expected return on plan assets	(501)	(486)	(446)	(34)	(37)	(40)
Amortization of prior service cost (credit)	12	12	14	(207)	(203)	(203)
Other adjustments (settlements, curtailments, etc.)	—	—	6	—	—	—
Pensions & OPEB mark-to-market adjustment	(267)	735	729	(129)	140	36
Net periodic cost	$ (187)	$ 811	$ 807	$ (320)	$ (41)	$ (146)

Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31[1]	Pensions			OPEB		
	2013	2012	2011	2013	2012	2011
Weighted-average discount rate	4.25%	5.00%	5.50%	4.00%	4.75%	5.00%
Expected long-term return on plan assets	7.75%	7.75%	8.25%	7.75%	7.75%	8.50%
Rate of compensation increase	4.70%	5.20%	5.20%	N/A	N/A	N/A

[1] Excludes Pensions & OPEB mark-to-market adjustment.

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pensions and OPEB obligations. The assumed rates of return on plan assets consider historical market returns and economic forecasts for the types of investments held by FirstEnergy's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

The following tables set forth pension financial assets that are accounted for at fair value by level within the fair value hierarchy. See Note 9, Fair Value Measurements, for a description of each level of the fair value hierarchy. There were no significant transfers between levels during 2013 and 2012.

	December 31, 2013				Asset Allocation
	Level 1	Level 2	Level 3	Total	
		(In millions)			
Cash and short-term securities	$ —	$ 782	$ —	$ 782	13%
Equity investments					
Domestic	701	3	—	704	11%
International	304	118	—	422	7%
Fixed income					
Government bonds	—	314	—	314	5%
Corporate bonds	—	2,128	—	2,128	34%
Mortgaged-backed securities (non-government)	—	87	—	87	1%
Alternatives					
Hedge funds	—	1,395	—	1,395	23%
Derivatives	—	14	—	14	—%
Private equity funds	—	—	27	27	—%
Real estate funds	—	—	385	385	6%
Total [1]	$ 1,005	$ 4,841	$ 412	$ 6,258	100%

	December 31, 2012				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 652	$ —	$ 652	10%
Equity investments					
Domestic	547	8	—	555	8%
International	275	153	—	428	7%
Fixed income					
Government bonds	4	564	—	568	8%
Corporate bonds	—	1,899	—	1,899	28%
High yield debt	—	369	—	369	6%
Mortgaged-backed securities (non-government)	—	330	—	330	5%
Alternatives					
Hedge funds	—	1,498	—	1,498	22%
Derivatives	—	18	—	18	—%
Private equity funds	—	—	33	33	1%
Real estate funds	—	—	357	357	5%
Total [1]	$ 826	$ 5,491	$ 390	$ 6,707	100%

[1] Excludes ($87) million and ($36) million as of December 31, 2013 and December 31, 2012, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

The following table provides a reconciliation of changes in the fair value of pension investments classified as Level 3 in the fair value hierarchy during 2013 and 2012:

	Private Equity Funds	Real Estate Funds	Derivatives
		(In millions)	
Balance as of January 1, 2012	$ 135	$ 327	$ 70
Actual return on plan assets:			
Unrealized gains	(14)	29	—
Realized gains	(10)	4	—
Purchases, sales and settlements	—	—	(70)
Transfers in (out)	(78)	(3)	—
Balance as of December 31, 2012	$ 33	$ 357	$ —
Actual return on plan assets:			
Unrealized gains	1	17	—
Realized gains	5	13	—
Purchases, sales and settlements	—	—	—
Transfers out	(12)	(2)	—
Balance as of December 31, 2013	$ 27	$ 385	$ —

As of December 31, 2013 and 2012, the OPEB trust investments measured at fair value were as follows:

	December 31, 2013				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 47	$ —	$ 47	9%
Equity investment					
Domestic	227	—	—	227	45%
International	4	2	—	6	1%
Mutual funds	5	—	—	5	1%
Fixed income					
U.S. treasuries	—	44	—	44	9%
Government bonds	—	91	—	91	18%
Corporate bonds	—	59	—	59	12%
High yield debt	—	—	—	—	—%
Mortgage-backed securities (non-government)	—	3	—	3	1%
Alternatives					
Hedge funds	—	17	—	17	3%
Private equity funds	—	—	—	—	—%
Real estate funds	—	—	5	5	1%
Total [1]	$ 236	$ 263	$ 5	$ 504	100%

	December 31, 2012				Asset Allocation
	Level 1	Level 2	Level 3	Total	
	(In millions)				
Cash and short-term securities	$ —	$ 83	$ —	$ 83	16%
Equity investment					
Domestic	183	—	—	183	36%
International	4	2	—	6	1%
Mutual funds	8	3	—	11	2%
Fixed income					
U.S. treasuries	—	48	—	48	9%
Government bonds	—	88	—	88	17%
Corporate bonds	—	59	—	59	11%
High yield debt	—	5	—	5	1%
Mortgage-backed securities (non-government)	—	9	—	9	2%
Alternatives					
Hedge funds	—	21	—	21	4%
Private equity funds	—	—	—	—	—%
Real estate funds	—	—	5	5	1%
Total [1]	$ 195	$ 318	$ 5	$ 518	100%

[1] Excludes ($9) million and ($10) million as of December 31, 2013 and December 31, 2012, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

The following table provides a reconciliation of changes in the fair value of OPEB trust investments classified as Level 3 in the fair value hierarchy during 2013 and 2012:

	Private Equity Funds	Real Estate Funds
	(in millions)	
Balance as of January 1, 2012	$ 3	$ 7
Actual return on plan assets:		
Unrealized losses	(1)	—
Realized gains (losses)	—	—
Purchases, sales and settlements	—	—
Transfers out	(2)	(2)
Balance as of December 31, 2012	$ —	$ 5
Balance as of December 31, 2013	$ —	$ 5

FirstEnergy follows a total return investment approach using a mix of equities, fixed income and other available investments while taking into account the pension plan liabilities to optimize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate and private equity are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

FirstEnergy's target asset allocations for its pensions and OPEB trust portfolios for 2013 and 2012 are shown in the following table:

	Target Asset Allocations	
	2013	2012
Equities	26%	20%
Fixed income	40%	51%
Absolute return strategies	22%	21%
Real estate	5%	5%
Private equity	1%	—%
Cash	6%	3%
	100%	100%

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(in millions)	
Effect on total of service and interest cost	$ 1	$ (1)
Effect on accumulated benefit obligation	$ 26	$ (23)

Taking into account estimated employee future service, FirstEnergy expects to make the following benefit payments from plan assets and other payments, net of participant contributions:

		OPEB	
	Pensions	Benefit Payments	Subsidy Receipts
		(in millions)	
2014	$ 449	$ 129	$ (4)
2015	466	67	(4)
2016	484	67	(4)
2017	500	67	(4)
2018	524	65	(4)
Years 2019-2023	2,867	382	(17)

FES' share of the net pensions and OPEB liability as of December 31, 2013 and 2012, was as follows:

	Pensions		OPEB	
	2013	2012	2013	2012
		(In millions)		
Net Liability	$ (149)	$ (180)	$ (8)	$ (36)

FES' share of the net periodic pensions and OPEB costs for the three years ended December 31, 2013 was as follows:

	Pensions			OPEB		
	2013	2012	2011	2013	2012	2011
			(In millions)			
Net Periodic Costs	$ (30)	$ 78	$ 80	$ (40)	$ (11)	$ (21)

4. STOCK-BASED COMPENSATION PLANS

FirstEnergy has four stock-based compensation plans - ICP, 401(k) Savings Plan, EDCP and DCPD, as described further below.

ICP

The ICP includes four forms of stock-based compensation — restricted stock, restricted stock units, stock options and performance shares.

Under the ICP, total issuances cannot exceed 29 million shares of common stock or their equivalent. Stock options, restricted stock and restricted stock units have currently been designated to pay out in common stock, with vesting periods ranging from eight months to ten years. Performance share awards are currently designated to be paid in cash unless the recipient elects to defer the award, in which case, the award may be paid in stock depending upon the duration of the deferral. Shares available under the ICP are also used for bonuses earned under FirstEnergy's Short-Term Incentive Program that are, at the election of the participant, deferred through the EDCP and paid in shares under the ICP. As of December 31, 2013, approximately 3.0 million shares were available for future issuance plus any shares that become available again under the ICP due to cancellations, forfeitures, cash settlements or other similar circumstances with respect to outstanding awards.

FirstEnergy records the compensation costs for stock-based compensation awards over the vesting period based on the fair value on the grant date, less estimated forfeitures. FirstEnergy records the actual tax benefit realized from tax deductions when awards are exercised or distributed. Realized tax benefits during the years ended December 31, 2013, 2012 and 2011 were $13 million, $22 million and $14 million, respectively. The excess of the deductible amount over the recognized compensation cost is recorded as a component of stockholders' equity and reported as an other financing activity on the Consolidated Statements of Cash Flows.

Restricted Stock and Restricted Stock Units

Restricted common stock (restricted stock) and restricted stock units (stock units) activity for the year ended December 31, 2013, was as follows:

Outstanding as of January 1, 2013	2,180,422
Granted	952,137
Vested	(815,851)
Forfeited	(100,099)
Outstanding as of December 31, 2013	2,216,609

The 952,137 shares of restricted stock and stock units granted during the year ended December 31, 2013, includes 212,211 stock units related to previous grants due to over-achievement of performance metrics, and had a grant-date fair value of $39.97 and a weighted-average vesting period of 3.02 years.

Eligible employees receive awards of FE restricted stock or stock units subject to restrictions that lapse over a defined period of time or upon achieving performance results. Dividends are received on the restricted stock and are reinvested in additional shares. Restricted stock grants under the ICP were as follows:

	2013	2012	2011
Restricted stock granted	27,561	263,771	297,859
Weighted average market price	$ 42.53	$ 44.82	$ 38.44
Weighted average vesting period (years)	3.68	3.09	2.27
Dividends restricted	Yes	Yes	Yes

Vesting activity for restricted stock during 2013 was as follows (forfeitures were not material):

Restricted Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2013	551,678	$ 46.73
Nonvested as of December 31, 2013	417,464	$ 45.46
Granted in 2013	27,561	$ 42.53
Vested in 2013[(1)]	167,751	$ 37.10

[(1)] Includes 23,446 shares for dividends earned during vesting period

FirstEnergy grants two types of stock unit awards: discretionary-based and performance-based. The discretionary-based awards grant the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of stock units set forth in each agreement. Performance-based awards grant the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of stock units set forth in the agreement subject to adjustment based on FirstEnergy's performance relative to financial and operational performance targets.

	2013	2012	2011
Restricted stock units granted	924,576	652,120	617,195
Weighted average vesting period (years)	3.00	3.00	3.00

Vesting activity for stock units during 2013 was as follows:

Restricted Stock Units	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2013	1,628,744	$ 41.10
Nonvested as of December 31, 2013	1,799,145	$ 40.86
Granted in 2013	924,576	$ 39.90
Forfeited in 2013	82,629	$ 41.38
Vested in 2013 [(1)]	792,113	$ 40.74

[(1)] Includes dividend equivalents of 120,567 earned during vesting period

As of December 31, 2013, there was $35 million of total unrecognized compensation cost related to non-vested share-based compensation arrangements granted for restricted stock and restricted stock units; that cost is expected to be recognized over a period of approximately 2 years.

Stock Options

Stock options were granted to eligible employees allowing them to purchase a specified number of common shares at a fixed grant price over a defined period of time. Stock option activity during 2013 was as follows:

Stock Option Activity	Number of Shares	Weighted Average Exercise Price
Balance, January 1, 2013 (2,348,469 options exercisable)	2,910,269	$ 40.33
Options exercised	(546,408)	30.37
Options forfeited	(4,735)	71.21
Balance, December 31, 2013 (1,997,969 options exercisable)	2,359,126	$ 42.59

Options outstanding and range of exercise prices as of December 31, 2013, were as follows:

	Options Outstanding		
Range of Exercise Prices	Shares	Weighted Average Exercise Price	Remaining Contractual Life (in years)
$20.02-$35.44	66,125	$ 22.83	0.47
$35.45-$38.75	1,143,389	$ 36.78	6.28
$38.76-$53.04	835,039	$ 38.81	0.19
$53.05-$81.19	314,573	$ 77.85	3.56
Total	2,359,126	$ 42.59	3.60

Cash received from the exercise of stock options in 2013, 2012 and 2011 was $19 million, $50 million and $32 million, respectively. The total intrinsic value of options exercised during 2013 was $6 million.

Performance Shares

Performance shares are share equivalents and do not have voting rights. The shares track the performance of FE's common stock over a three-year vesting period. During that time, dividend equivalents accrue and at vesting are converted into additional performance shares. The final account value may be adjusted based on the ranking of FE stock performance to a composite of peer companies. During 2013, 2012 and 2011, no cash was paid to settle performance shares due to the criteria not being met for the previous three-year vesting period.

401(k) Savings Plan

In 2013, 2012 and 2011, shares of FE common stock were purchased on the market and contributed to participants' accounts.

EDCP

Under the EDCP, covered employees can direct a portion of their compensation, including annual incentive awards and/or long-term incentive awards, into unfunded FE stock accounts to receive vested stock units or into an unfunded retirement cash account. Dividends are calculated quarterly on stock units outstanding and are credited in the form of additional stock units. Upon withdrawal, stock units are converted to FE shares. Payout of the stock accounts typically occurs three years from the date of deferral; however, an election can be made in the year prior to payout to further defer shares into a retirement stock account that will pay out in cash upon retirement. Interest is calculated on the cash allocated to the cash account and the total balance will pay out in cash upon retirement.

DCPD

Under the DCPD, members of the Board of Directors can elect to allocate all or a portion of their equity retainers to deferred stock and their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. The net liability recognized for DCPD of approximately $7 million and $6 million as of December 31, 2013 and December 31, 2012, respectively, is included in the caption "Retirement benefits" on the Consolidated Balance Sheets.

Of the approximately 1.7 million shares authorized under the EDCP and DCPD, approximately 845,000 shares were available for future issuance as of December 31, 2013. The shareholder approved pools for the EDCP and DCPD terminate in May 2014.

Stock-based Compensation Expense

Pre-tax stock-based compensation costs, tax benefit associated with stock-based compensation expense, and the amount of stock-based compensation expense capitalized related to FirstEnergy and FES plans are included in the following tables:

FirstEnergy	Years ended December 31,		
Stock-based Compensation Plan	**2013**	**2012**	**2011**
		(In millions)	
Restricted Stock and Restricted Stock Units	$ 42	$ 42	$ 29
Stock Options	—	1	1
Performance Shares	(10)	5	3
401(k) Savings Plan	25	37	31
EDCP	(2)	—	6
DCPD	5	4	4
Total	$ 60	$ 89	$ 74
Stock-based compensation costs capitalized	$ 20	$ 29	$ 21

FES	Years ended December 31,		
Stock-based Compensation Plan	**2013**	**2012**	**2011**
		(In millions)	
Restricted Stock and Restricted Stock Units	$ 6	$ 6	$ 4
Performance Shares	(1)	1	1
401(k) Savings Plan	4	6	5
EDCP	—	—	1
Total	$ 9	$ 13	$ 11
Stock-based compensation costs capitalized	$ 1	$ 1	$ —

Tax benefits associated with stock based compensation plan expense was $23 million, $11 million and $10 million (FES - $1 million, $2 million and $2 million) for the years ended 2013, 2012 and 2011, respectively.

5. TAXES

FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

PROVISION FOR INCOME TAXES	FirstEnergy	FES
	(In millions)	
2013		
Currently payable (receivable)-		
Federal	$ (118)	$ (300)
State	70	(3)
	(48)	(303)
Deferred, net-		
Federal	305	317
State	(54)	(4)
	251	313
Investment tax credit amortization	(8)	(4)
Total provision for income taxes	$ 195	$ 6
2012		
Currently payable (receivable)-		
Federal	$ (130)	$ (128)
State	28	17
	(102)	(111)
Deferred, net-		
Federal	580	209
State	78	9
	658	218
Investment tax credit amortization	(11)	(4)
Total provision for income taxes	$ 545	$ 103
2011		
Currently payable (receivable)-		
Federal	$ (251)	$ (224)
State	19	9
	(232)	(215)
Deferred, net-		
Federal	785	205
State	24	(2)
	809	203
Investment tax credit amortization	(11)	(4)
Total provision for income taxes	$ 566	$ (16)

As discussed in Note 11, on July 8, 2013, officers of FirstEnergy and AE Supply committed to deactivating two coal-fired generating plants. As a result of the decision, FirstEnergy determined that it is more likely than not that certain state and local NOL carryforwards will not be realized through future operations or through the reversal of existing temporary differences. As a result, FirstEnergy recorded a valuation reserve of approximately $20 million against carryforwards in 2013.

On July 9, 2013, Pennsylvania House Bill 465 (HB 465) was enacted, adopting new market-based sourcing rules for certain items of income as well as increasing the Pennsylvania NOL deduction credit for tax years beginning after December 31, 2013 and 2014 to the greater of 25% or $4 million of taxable income and 30% or $5 million of taxable income, respectively. Based on income projections, Pennsylvania NOL valuation reserves were reduced by approximately $8 million in 2013.

During 2013, FirstEnergy made changes to state apportionment factors in certain jurisdictions based on sales sourcing rules for electricity, which reduced deferred tax liabilities by approximately $9 million. Furthermore, based on an assessment of business operations, FirstEnergy determined that income from certain subsidiaries should not be apportioned to certain tax jurisdictions due to the absence of business nexus. This assessment resulted in a reduction to deferred tax liabilities of approximately $22 million.

In 2012, a $50 million valuation allowance was established for two unregulated subsidiaries of FirstEnergy based on current judgment as to the realization of certain state deferred tax assets, as impacted by changes in the business and the applicability of certain

state law limitations on the long-term utilization of NOL carryforwards. The results of operations in 2012 for those companies decreased accumulated deferred income tax liabilities by approximately $50 million.

In December 2012, two subsidiaries of FES, FG and NG, completed a conversion from corporations to limited liability companies (LLCs). For income tax purposes, these LLCs are treated as divisions (*i.e.*, disregarded entities) of their parent company, FES. The LLC conversions, in combination with anticipated future taxable income, will contribute to the realization of certain state deferred tax assets. In 2011, an unregulated subsidiary of FirstEnergy converted to an LLC which, based on anticipated future taxable income, resulted in the partial reversal of a valuation allowance, reducing income tax expense in 2011 by $27 million.

During 2012, certain FirstEnergy operating companies adopted a new federal tax accounting method (effective for the 2011 consolidated federal tax return) for the deductibility of expenses for repairs to transmission and distribution assets, pursuant to IRS safe harbor guidance. In accordance with the IRS guidance, a cumulative adjustment was made on the 2011 consolidated federal tax return, increasing tax deductions and decreasing taxable income by approximately $417 million. The increased federal tax deductions created a corresponding state tax benefit that reduced FirstEnergy's effective tax rate by approximately $12 million in 2012. The IRS has agreed that the new method of accounting is compliant with the IRS guidance.

FES and the Utilities are party to an intercompany income tax allocation agreement with FirstEnergy and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FirstEnergy, excluding any tax benefits derived from interest expense associated with acquisition indebtedness from the merger with GPU, are reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit.

The following tables provide a reconciliation of federal income tax expense at the federal statutory rate to the total provision for income taxes for the three years ended December 31, 2013:

	FirstEnergy	FES
	(In millions)	
2013		
Book income before provision for income taxes	$ 570	$ 52
Federal income tax expense at statutory rate	$ 199	$ 18
Increases (reductions) in taxes resulting from-		
Amortization of investment tax credits	(8)	(4)
State income taxes, net of federal tax benefit	10	(5)
FirstEnergy effectively settled tax items	(2)	—
ESOP Dividend	(9)	(2)
Nondeductible compensation	3	—
Other permanent items	1	—
AFUDC equity and other flow-through	(7)	—
Other, net	8	(1)
Total provision for income taxes	$ 195	$ 6
2012		
Book income before provision for income taxes	$ 1,299	$ 276
Federal income tax expense at statutory rate	$ 455	$ 97
Increases (reductions) in taxes resulting from-		
Amortization of investment tax credits	(11)	(4)
State income taxes, net of federal tax benefit	69	17
Medicare Part D	32	1
Effectively settled tax items	(20)	(11)
State valuation allowance	60	—
State apportionment remeasurement	(50)	—
Other, net	10	3
Total provision for income taxes	$ 545	$ 103
2011		
Book income before provision for income taxes	$ 1,438	$ (83)
Federal income tax expense (benefit) at statutory rate	$ 503	$ (29)
Increases (reductions) in taxes resulting from-		
Amortization of investment tax credits	(11)	(4)
State income taxes, net of federal tax benefit	28	5
State unitary tax adjustments	33	—
Manufacturing deduction	16	13
Medicare Part D	36	4
Effectively settled tax items	(11)	(2)
State valuation allowance	(19)	2
Other, net	(9)	(5)
Total provision for income taxes (benefits)	$ 566	$ (16)

Accumulated deferred income taxes as of December 31, 2013 and 2012 are as follows:

	FirstEnergy	FES
	(In millions)	
December 31, 2013		
Property basis differences	$ 8,078	$ 1,428
Regulatory transition charge	(26)	—
Customer receivables for future income taxes	(2)	—
Deferred MISO/PJM transmission costs	27	—
Other regulatory assets — RCP	69	—
Deferred sale and leaseback gain	(411)	(370)
Non-utility generation costs	(1)	—
Unamortized investment tax credits	(62)	(16)
Unrealized losses on derivative hedges	(20)	(1)
Pensions and OPEB	(938)	(77)
Lease market valuation liability	(59)	55
Oyster Creek securitization (Note 12)	57	—
Nuclear decommissioning activities	44	31
Mark-to-market adjustments	31	30
Deferred gain for asset sales — affiliated companies	781	—
Loss carryforwards and AMT credits	(1,599)	(369)
Loss carryforward valuation reserve	142	18
Storm damage	179	—
Market transition charge	81	—
All other	231	(13)
Net deferred income tax liability	$ 6,602	$ 716
December 31, 2012		
Property basis differences	$ 7,868	$ 1,060
Regulatory transition charge	79	—
Customer receivables for future income taxes	130	—
Deferred MISO/PJM transmission costs	125	—
Other regulatory assets — RCP	161	—
Deferred sale and leaseback gain	(431)	(384)
Non-utility generation costs	5	—
Unamortized investment tax credits	(67)	(17)
Unrealized losses on derivative hedges	(21)	2
Pensions and OPEB	(1,102)	(105)
Lease market valuation liability	(81)	33
Oyster Creek securitization (Note 12)	75	—
Nuclear decommissioning activities	127	111
Mark-to-market adjustments	30	30
Loss carryforwards and ATM credits	(1,199)	(221)
Loss carryforward valuation reserve	102	16
Storm damage	192	—
Market transition charge	65	—
All other	239	(22)
Net deferred income tax liability	$ 6,297	$ 503

FirstEnergy accounts for uncertainty in income taxes recognized in its financial statements. Accounting guidance prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of tax positions taken or expected to be taken on a company's tax return. As of December 31, 2013 and 2012, FirstEnergy's total unrecognized income tax benefits were approximately $48 million and $43 million, respectively. All $48 million of unrecognized income tax benefits as of December 31, 2013, would impact the effective tax rate if ultimately recognized in future years. As of December 31, 2013, it is

reasonably possible that approximately $35 million of unrecognized tax benefits may be resolved during 2014 as a result of the statute of limitations expiring, all of which would affect FirstEnergy's effective tax rate.

During 2013, the AE companies reduced reserves for unrecognized tax benefits related to various tax positions, with a total reduction to the effective tax rate of approximately $5 million.

During 2013, FirstEnergy settled a claim with the IRS for approximately $1.0 billion of additional accelerated (bonus) depreciation deductions for certain generation property for the 2010 taxable year, which resulted in a carryback refund of approximately $110 million, an increase in the NOL carryfoward of approximately $65 million, with a corresponding increase to accumulated deferred income taxes for this temporary tax item and an overall decrease to FirstEnergy's effective tax rate of approximately $2 million for adjustments to interest resulting from the settlement.

During 2012, FirstEnergy reached a settlement with state authorities related to state apportionment factors in Pennsylvania on an intercompany asset sale, which reduced FirstEnergy's effective tax rate by $3 million. During 2012, based on further IRS guidance related to the tax accounting for costs to repair and maintain fixed assets, the AE companies reduced their amount of unrecognized tax benefits by $21 million, with a corresponding adjustment to accumulated deferred income taxes for this temporary tax item, with no resulting impact to the effective tax rate.

During the fourth quarter of 2012, FirstEnergy reached a settlement with the IRS on deductions for prior year costs to repair generation assets, permitting the reduction of unrecognized tax benefits by approximately $34 million, with a corresponding adjustment to accumulated deferred income taxes for this temporary tax item, and an overall decrease to FirstEnergy's effective tax rate of approximately $10 million for adjustments to potential interest expense resulting from the settlement. Also during the fourth quarter of 2012, the AE companies reduced reserves for unrecognized tax benefits related to various tax positions, including the IRS's agreement on AE's deduction of merger-related expenses, with a total reduction to the effective tax rate of approximately $7 million.

The following table summarizes the changes in unrecognized tax positions for the years ended 2013, 2012 and 2011:

	FirstEnergy	FES
	(In millions)	
Balance, January 1, 2011	$ 45	$ 41
Increase due to merger with AE	97	—
Prior years increases	10	8
Prior years decreases	(35)	(4)
Balance, December 31, 2011	$ 117	$ 45
Current year increases	2	—
Current year decreases	(7)	—
Prior years increases	6	6
Prior years decreases	(37)	(13)
Decrease for settlements	(38)	(35)
Balance, December 31, 2012	$ 43	$ 3
Prior years increases	10	—
Prior years decreases	(5)	—
Balance, December 31, 2013	$ 48	$ 3

FirstEnergy recognizes interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized and the amount previously taken or expected to be taken on the federal income tax return. FirstEnergy includes net interest and penalties in the provision for income taxes. FirstEnergy's reversal of accrued interest associated with unrecognized tax benefits was immaterial to FirstEnergy's effective tax rate in 2013 and reduced the 2012 effective tax rate by approximately $4 million. The interest associated with the 2011 settlement of a claim favorably affected FirstEnergy's effective tax rate by $7 million in 2011.

The following table summarizes the net interest expense (income) for the three years ended December 31, 2013 and the cumulative net interest payable as of December 31, 2013 and 2012:

	Net Interest Expense (Income) For the Years Ended December 31,			Net Interest Payable As of December 31,	
	2013	2012	2011	2013	2012
		(In millions)		*(In millions)*	
FirstEnergy	$ 1	$ (4)	$ (5)	$ 9	$ 8
FES	—	(4)	1	1	1

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS (2011-2013) and state tax authorities. FirstEnergy's tax returns for all state jurisdictions are open from 2009-2012. The IRS completed its audit of the 2011 tax year in December 2013 and is in the process of preparing the final audit report. Tax years 2012-2013 are under review by the IRS. In August 2013 the IRS completed its audit of AE for tax years 2009 and 2010 and the final federal tax return for the period January-February 2011. For the remainder of the 2011 taxable year and future years, the AE companies are part of the FirstEnergy federal consolidated group. State tax returns for tax years 2010 through 2012 remain subject to review in Pennsylvania, West Virginia, Maryland and Virginia for certain subsidiaries of AE.

FirstEnergy has recorded as deferred income tax assets the effect of NOLs and tax credits that will more likely than not be realized through future operations and through the reversal of existing temporary differences. As of December 31, 2013, the deferred income tax assets, before any valuation allowances, consisted of $1.1 billion of federal NOL carryforwards that expire from 2025 to 2033, federal AMT credits of $25 million that have an indefinite carryforward period, and $418 million of state and local NOL carryforwards that begin to expire in 2014.

The table below summarizes pre-tax NOL carryforwards for state and local income tax purposes of approximately $9.8 billion for FirstEnergy, of which approximately $6.3 billion is expected to be utilized based on current estimates and assumptions. The ultimate utilization of these NOLs may be impacted by statutory limitations on the use of NOLs imposed by state and local tax jurisdictions, changes in statutory tax rates, and changes in business which, among other things, impact both future profitability and the manner in which future taxable income is apportioned to various state and local tax jurisdictions.

Expiration Period	FirstEnergy		FES	
	(In millions)			
	State	Local	State	Local
2014-2018	$ 14	$ 2,289	$ 8	$ 1,243
2019-2023	2,513	—	23	—
2024-2028	2,051	—	60	—
2029-2033	2,891	—	752	—
	$ 7,469	$ 2,289	$ 843	$ 1,243

General Taxes

	FirstEnergy	FES
	(In millions)	
2013		
KWH excise	$ 219	$ —
State gross receipts	240	77
Real and personal property	368	40
Social security and unemployment	110	19
Other	41	2
Total general taxes	$ 978	$ 138
2012		
KWH excise	$ 230	$ —
State gross receipts	251	77
Real and personal property	328	35
Social security and unemployment	126	20
Other	49	4
Total general taxes	$ 984	$ 136
2011		
KWH excise	$ 244	$ —
State gross receipts	264	62
Real and personal property	298	42
Social security and unemployment	109	14
Other	62	6
Total general taxes	$ 977	$ 124

6. LEASES

FirstEnergy leases certain generating facilities, office space and other property and equipment under cancelable and noncancelable leases.

In 1987, OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years. In that same year, CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and Bruce Mansfield Units 1, 2 and 3 and entered into similar operating leases for lease terms of approximately 30 years. During the terms of their respective leases, OE, CEI and TE are responsible, to the extent of their leasehold interests, for costs associated with the units including construction expenditures, operation and maintenance expenses, insurance, nuclear fuel, property taxes and decommissioning. They have the right, at the expiration of the respective basic lease terms, to renew their respective leases. They also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities. The basic rental payments are adjusted when applicable federal tax law changes.

In 2007, FG completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1 and entered into operating leases for basic lease terms of approximately 33 years. FES has unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases.

During 2008, NG purchased 56.8 MW of lessor equity interests in the OE 1987 sale and leaseback of the Perry Plant and approximately 43.5 MW of lessor equity interests in the OE 1987 sale and leaseback of Beaver Valley Unit 2. In addition, NG purchased 158.5 MW of lessor equity interests in the TE and CEI 1987 sale and leaseback of Beaver Valley Unit 2. The Ohio Companies continue to lease these MW under their respective sale and leaseback arrangements and the related lease debt remains outstanding.

During 2012, NG repurchased 70.1 MW of lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $129 million and FG acquired 441.9 MW of certain equity and other lessor interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for approximately $262 million. In March of 2013, FG acquired the remaining lessor interests in the Bruce Mansfield sale and leaseback transaction for approximately $221 million. During 2013, NG purchased 12.2 MW of lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $23 million. Additionally, in February 2014, NG purchased 47.7 MW of lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million.

Established by OE in 1996, PNBV purchased a portion of the lease obligation bonds issued on behalf of lessors in OE's Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. Similarly, CEI and TE established Shippingport in 1997 to purchase the lease obligation bonds issued on behalf of lessors in their Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. During 2013, the investments held at Shippingport were liquidated. The PNBV arrangements effectively reduce lease costs related to those transactions (see Note 8, Variable Interest Entities).

As of December 31, 2013, FirstEnergy's leasehold interest was 8.11% of Perry Unit 1 and 93.83% of Bruce Mansfield Unit 1. After NG's purchase in February 2014, as discussed above, FirstEnergy's leasehold interest was 2.60% of Beaver Valley Unit 2.

Operating lease expense for 2013, 2012 and 2011, is summarized as follows:

(In millions)	2013	2012	2011
FirstEnergy	$ 224	$ 291	$ 319
FES	97	140	154

The future minimum capital lease payments as of December 31, 2013 are as follows:

Capital leases	FirstEnergy	FES
	(In millions)	
2014	$ 40	$ 6
2015	38	6
2016	34	5
2017	30	5
2018	23	2
Years thereafter	57	—
Total minimum lease payments	222	24
Interest portion	(34)	(2)
Present value of net minimum lease payments	188	22
Less current portion	34	5
Noncurrent portion	$ 154	$ 17

FirstEnergy's future minimum consolidated operating lease payments as of December 31, 2013, are as follows:

	FirstEnergy		
Operating Leases	Lease Payments	Capital Trust	Net
		(In millions)	
2014	$ 250	$ 48	$ 202
2015	245	40	205
2016	213	13	200
2017	128	3	125
2018	126	—	126
Years thereafter	1,564	—	1,564
Total minimum lease payments	$ 2,526	$ 104	$ 2,422

FES' future minimum operating lease payments as of December 31, 2013, are as follows:

Operating Leases	Lease Payments
	(In millions)
2014	$ 143
2015	142
2016	130
2017	82
2018	101
Years thereafter	1,480
Total minimum lease payments	$ 2,078

7. INTANGIBLE ASSETS

As of December 31, 2013, intangible assets classified in Other Deferred Charges on FirstEnergy's Consolidated Balance Sheet, include the following:

	Intangible Assets			Amortization Expense						
				Actual	Estimated					
(In millions)	Gross	Accumulated Amortization	Net	2013	2014	2015	2016	2017	2018	Thereafter
NUG contracts[1][2]	$ 124	$ 15	$ 109	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 84
OVEC[1]	54	5	49	2	2	2	2	2	2	39
Coal contracts[1][3]	556	222	334	62	55	51	51	45	30	49
FES customer contracts	147	52	95	17	17	17	17	17	14	13
Energy contracts[1]	136	135	1	14	1	—	—	—	—	—
	$ 1,017	$ 429	$ 588	$ 100	$ 80	$ 75	$ 75	$ 69	$ 51	$ 185

(1) Fair value measurements of intangible assets recorded in connection with the Allegheny merger (see Note 21, Merger).
(2) NUG contracts are subject to regulatory accounting and their amortization does not impact earnings.
(3) A gross amount of $102 million ($53 million, net) of the coal contracts was recorded with a regulatory offset and the amortization does not impact earnings.

FES acquired certain customer contract rights which were capitalized as intangible assets. These rights allow FES to supply electric generation to customers, and the recorded value is being amortized ratably over the term of the related contracts.

8. VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses to determine whether a variable interest gives FirstEnergy a controlling financial interest in a VIE. This analysis identifies the primary beneficiary of a VIE as the enterprise that has both the power to direct the activities of a VIE that most significantly impact the entity's economic performance and the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE. FirstEnergy consolidates a VIE when it is determined that it is the primary beneficiary.

VIEs included in FirstEnergy's consolidated financial statements are: FEV's joint venture in the Signal Peak mining and coal transportation operations, a portion of which was sold on October 18, 2011, and resulted in deconsolidation; the PNBV and Shippingport capital trusts that were created to refinance debt originally issued in connection with sale and leaseback transactions; wholly-owned limited liability companies of the Ohio Companies (as described below); wholly owned limited liability companies of JCP&L created to sell transition bonds to securitize the recovery of JCP&L's bondable stranded costs and special purpose limited liability companies created to issue environmental control bonds that were used to construct environmental control facilities (see Note 12, Capitalization for additional details).

The caption noncontrolling interest within the consolidated financial statements is used to reflect the portion of a VIE that FirstEnergy consolidates, but does not own. The change in noncontrolling interest within the Consolidated Balance Sheets during the year ended December 31, 2013, was primarily due to $7 million of distributions to owners. As of December 31, 2013, the caption noncontrolling interest on the consolidated Balance Sheets was primarily related to PNBV.

In order to evaluate contracts for consolidation treatment and entities for which FirstEnergy has an interest, FirstEnergy aggregates variable interests into the following categories based on similar risk characteristics and significance.

Ohio Securitization

In September 2012, the Ohio Companies formed CEI Funding LLC, OE Funding LLC and TE Funding LLC, respectively, as separate, wholly-owned limited liability SPEs. Each SPE is a bankruptcy-remote, special purpose limited liability company that is restricted to activities necessary to issue phase-in recovery bonds and perform other functions in connection with the bond issuance. Creditors of FirstEnergy and the Ohio Companies have no recourse to any assets or revenues of the SPEs. The phase-in recovery bonds issued by these SPEs are payable only from, and secured by, phase-in recovery property held by the SPEs (i.e. the right to impose, charge and collect irrevocable non-bypassable usage-based charges payable by retail electric customers in the service territories of the Ohio Companies) and the bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. The SPEs are considered VIEs and each one is consolidated into its applicable utility. In June 2013, the SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds with a weighted average coupon of 2.48% to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds were sold to a trust that concurrently sold a like aggregate amount of its pass through trust certificates to public investors. The proceeds were primarily used to redeem $410 million in existing taxable bonds of the Ohio Companies with a weighted average coupon of 5.71%, including $30 million of make-whole premiums. The

securitization effectively allows for the recovery of the make-whole premiums and transactional costs through the imposition of non-bypassable phase-in recovery charges on retail electric customers of the Ohio Companies pursuant to Ohio law. The $410 million of redemption consisted of original maturities of $225 million due 2013, $150 million due 2015 and $35 million due 2020. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

Mining Operations

In 2008, FEV entered into a joint venture in the Signal Peak mining and coal transportation operations near Roundup, Montana. FEV made equity investments totaling $134 million in exchange for a 50% economic interest in the joint venture. On October 18, 2011, Pinesdale LLC, a subsidiary of Gunvor Group, Ltd., purchased a one-third interest in the Signal Peak joint venture in which FEV held a 50% interest. As part of the transaction, FirstEnergy received $258 million in proceeds and retained a 33-1/3% equity ownership in Global Holding, the holding company for the joint venture. The sale resulted in a pre-tax gain of approximately $569 million ($370 million after-tax), which included $379 million from the remeasurement of FEV's retained investment. The gain attributed to the retained investment remeasurement is being amortized as coal is extracted from the mine on a units of production method.

Prior to the sale, FirstEnergy consolidated this joint venture since FEV was determined to be the primary beneficiary of the VIE. As a result of the sale, FEV was no longer determined to be the primary beneficiary and its retained 33-1/3%% interest is subject to the equity method of accounting.

Trusts

FirstEnergy's consolidated financial statements include PNBV and Shippingport. FirstEnergy used debt and available funds to purchase the notes issued by PNBV and Shippingport for the purchase of lease obligation bonds. Ownership of PNBV includes a 3% equity interest by an unaffiliated third party and a 3% equity interest held by OES Ventures, a wholly owned subsidiary of OE. During 2013, the investments held at Shippingport were liquidated.

PATH-WV

PATH is a series limited liability company that is comprised of multiple series, each of which has separate rights, powers and duties regarding specified property and the series profits and losses associated with such property. A subsidiary of AE owns 100% of the Allegheny Series (PATH-Allegheny) and 50% of the West Virginia Series (PATH-WV), which is a joint venture with a subsidiary of AEP. FirstEnergy is not the primary beneficiary of PATH-WV, as it does not have control over the significant activities affecting the economics of the portion of the PATH project that was to be constructed by PATH-WV.

On August 24, 2012, PJM removed the PATH project from its long-range expansion plans. See Note 15, Regulatory Matters, for additional information on the abandonment of PATH.

Power Purchase Agreements

FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent that they own a plant that sells substantially all of its output to the applicable utilities and the contract price for power is correlated with the plant’s variable costs of production. FirstEnergy maintains 21 long-term power purchase agreements with NUG entities that were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities.

FirstEnergy has determined that for all but two of these NUG entities, it does not have variable interests in the entities or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold variable interests in the remaining two entities; however, it applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

Because FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred to be recovered from customers. Purchased power costs related to the contracts that may contain a variable interest were $185 million and $253 million during the years ended December 31, 2013 and 2012, respectively.

In 1998 the PPUC issued an order approving a transition plan for WP that disallowed certain costs, including an estimated amount for an adverse power purchase commitment related to the NUG entity wherein WP may hold a variable interest, for which WP has taken the scope exception. On November 20, 2012, WP entered into an agreement to terminate the adverse power purchase commitment and accrued a pre-tax loss of $17 million. WP terminated the adverse commitment on January 1, 2013. WP's liability for this adverse purchase power commitment was $60 million, which included the $17 million accrual and was paid in January 2013.

Sale and Leaseback

FirstEnergy has variable interests in certain sale and leaseback transactions. FirstEnergy is not the primary beneficiary of these interests as it does not have control over the significant activities affecting the economics of the arrangements. See Note 6, Leases for additional details.

FES, and other FE subsidiaries are exposed to losses under their applicable sale and leaseback agreements upon the occurrence of certain contingent events. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events. Net discounted lease payments would not be payable if the casualty loss payments were made. The following table discloses each company's net exposure to loss based upon the casualty value provisions as of December 31, 2013:

	Maximum Exposure	Discounted Lease Payments, net[1]	Net Exposure
		(In millions)	
FES	$ 1,274	$ 1,063	$ 211
Other FE subsidiaries	752	289	463

[1] The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments is $1.1 billion.

9. FAIR VALUE MEASUREMENTS

RECURRING FAIR VALUE MEASUREMENTS

Authoritative accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. The three levels of the fair value hierarchy and a description of the valuation techniques are as follows:

Level 1 - Quoted prices for identical instruments in active market

Level 2 - Quoted prices for similar instruments in active market
- Quoted prices for identical or similar instruments in markets that are not active
- Model-derived valuations for which all significant inputs are observable market data

Models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Level 3 - Valuation inputs are unobservable and significant to the fair value measurement

FirstEnergy produces a long-term power and capacity price forecast annually with periodic updates as market conditions change. When underlying prices are not observable, prices from the long-term price forecast, which has been reviewed and approved by FirstEnergy's Risk Policy Committee, are used to measure fair value. A more detailed description of FirstEnergy's valuation process for FTRs, NUGs and LCAPPs are as follows:

FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly day-ahead congestion price differences across transmission paths. FTRs are acquired by FirstEnergy in the annual, monthly and long-term RTO auctions and are initially recorded using the auction clearing price less cost. After initial recognition, FTRs' carrying values are periodically adjusted to fair value using a mark-to-model methodology, which approximates market. The primary inputs into the model, which are generally less observable than objective sources, are the most recent RTO auction clearing prices and the FTRs' remaining hours. The model calculates the fair value by multiplying the most recent auction clearing price by the remaining FTR hours less the prorated FTR cost. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement. See Note 10, Derivative Instruments, for additional information regarding FirstEnergy's FTRs.

NUG contracts represent purchase power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. NUG contract carrying values are recorded at fair value and adjusted periodically using a mark-to-model methodology, which approximates market. The primary unobservable inputs into the model are regional power prices and generation MWH. Pricing for the NUG contracts is a combination of

market prices for the current year and next three years based on observable data and internal models using historical trends and market data for the remaining years under contract. The internal models use forecasted energy purchase prices as an input when prices are not defined by the contract. Forecasted market prices are based on ICE quotes and management assumptions. Generation MWH reflects data provided by contractual arrangements and historical trends. The model calculates the fair value by multiplying the prices by the generation MWH. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement.

LCAPP contracts are financially settled agreements that allow eligible generators to receive payments from, or make payments to, JCP&L, pursuant to an annually calculated load-ratio share of the capacity produced by the generator based upon the annual forecasted peak demand as determined by PJM. LCAPP contracts are recorded at fair value and adjusted periodically using a mark-to-model methodology, which approximates market. The primary unobservable input into the model is forecasted regional capacity prices. Pricing for the LCAPP contracts is a combination of PJM RPM capacity auction prices and internal models using historical trends and market data for the remaining years under contract. Capacity prices beyond the 2016/2017 delivery year are developed through a simulation of future PJM RPM auctions. The capacity price forecast assumes a continuation of the current PJM RPM market design and is reflective of the regional peak demand growth and generation fleet additions and retirements that underlie FirstEnergy's long-term energy price forecast. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement. During the fourth quarter of 2013, all LCAPP contracts were terminated. See Note 10, Derivative Instruments for additional information.

FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of December 31, 2013, from those used as of December 31, 2012. The determination of the fair value measures takes into consideration various factors, including but not limited to, nonperformance risk, counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of these forms of risk was not significant to the fair value measurements.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the years ended December 31, 2013 and 2012. The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:

FirstEnergy

Recurring Fair Value Measurements	December 31, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets				*(In millions)*				
Corporate debt securities	$ —	$ 1,365	$ —	$ 1,365	$ —	$ 1,259	$ —	$ 1,259
Derivative assets - commodity contracts	7	208	—	215	—	252	—	252
Derivative assets - FTRs	—	—	4	4	—	—	8	8
Derivative assets - NUG contracts[1]	—	—	20	20	—	—	36	36
Equity securities[2]	317	—	—	317	310	—	—	310
Foreign government debt securities	—	109	—	109	—	126	—	126
U.S. government debt securities	—	165	—	165	—	179	—	179
U.S. state debt securities	—	228	—	228	—	299	—	299
Other[3]	187	255	—	442	126	227	—	353
Total assets	$ 511	$ 2,330	$ 24	$ 2,865	$ 436	$ 2,342	$ 44	$ 2,822
Liabilities								
Derivative liabilities - commodity contracts	$ (13)	$ (100)	$ —	$ (113)	$ (3)	$ (151)	$ —	$ (154)
Derivative liabilities - FTRs	—	—	(12)	(12)	—	—	(9)	(9)
Derivative liabilities - NUG contracts[1]	—	—	(222)	(222)	—	—	(290)	(290)
Derivative liabilities - LCAPP contracts[1]	—	—	—	—	—	—	(144)	(144)
Total liabilities	$ (13)	$ (100)	$ (234)	$ (347)	$ (3)	$ (151)	$ (443)	$ (597)
Net assets (liabilities)[4]	$ 498	$ 2,230	$ (210)	$ 2,518	$ 433	$ 2,191	$ (399)	$ 2,225

(1) NUG and LCAPP contracts are subject to regulatory accounting treatment and do not impact earnings.

(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.

(3) Primarily consists of short-term cash investments.

(4) Excludes $10 million and $110 million as of December 31, 2013 and December 31, 2012, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts, LCAPP contracts, and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2013 and December 31, 2012:

	NUG Contracts[1]			LCAPP Contracts[1]			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
					(In millions)				
January 1, 2012 Balance	$ 57	$ (349)	$ (292)	$ —	$ —	$ —	$ 1	$ (23)	$ (22)
Unrealized gain (loss)	(20)	(180)	(200)	—	1	1	6	(6)	—
Purchases	—	—	—	—	(145)	(145)	13	(10)	3
Settlements	(1)	239	238	—	—	—	(12)	30	18
December 31, 2012 Balance	$ 36	$ (290)	$ (254)	$ —	$ (144)	$ (144)	$ 8	$ (9)	$ (1)
Unrealized gain (loss)	(8)	(17)	(25)	—	(22)	(22)	3	1	4
Purchases	—	—	—	—	—	—	6	(15)	(9)
Terminations[2]	—	—	—	—	166	166	—	—	—
Settlements	(8)	85	77	—	—	—	(13)	11	(2)
December 31, 2013 Balance	$ 20	$ (222)	$ (202)	$ —	$ —	$ —	$ 4	$ (12)	$ (8)

(1) Changes in the fair value of NUG and LCAPP contracts are generally subject to regulatory accounting treatment and do not impact earnings.
(2) See Note 10, Derivative Instruments.

Level 3 Quantitative Information

The following table provides quantitative information for FTRs and NUG contracts that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2013:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (8)	Model	RTO auction clearing prices	($2.80) to $5.20	$0.60	Dollars/MWH
NUG Contracts	$ (202)	Model	Generation	600 to 5,641,000	1,529,000	MWH
			Regional electricity prices	$51.70 to $57.30	$53.80	Dollars/MWH

FES

Recurring Fair Value Measurements	December 31, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets				*(In millions)*				
Corporate debt securities	$ —	$ 792	$ —	$ 792	$ —	$ 703	$ —	$ 703
Derivative assets - commodity contracts	7	208	—	215	—	252	—	252
Derivative assets - FTRs	—	—	3	3	—	—	6	6
Equity securities[1]	207	—	—	207	294	—	—	294
Foreign government debt securities	—	65	—	65	—	61	—	61
U.S. government debt securities	—	27	—	27	—	27	—	27
Other[2]	—	176	—	176	—	104	—	104
Total assets	$ 214	$ 1,268	$ 3	$ 1,485	$ 294	$ 1,147	$ 6	$ 1,447
Liabilities								
Derivative liabilities - commodity contracts	$ (13)	$ (100)	$ —	$ (113)	$ (3)	$ (151)	$ —	$ (154)
Derivative liabilities - FTRs	—	—	(11)	(11)	—	—	(6)	(6)
Total liabilities	$ (13)	$ (100)	$ (11)	$ (124)	$ (3)	$ (151)	$ (6)	$ (160)
Net assets (liabilities)[3]	$ 201	$ 1,168	$ (8)	$ 1,361	$ 291	$ 996	$ —	$ 1,287

(1) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.

(2) Primarily consists of short-term cash investments.

(3) Excludes $9 million and $94 million as of December 31, 2013 and December 31, 2012, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the periods ended December 31, 2013 and December 31, 2012:

	Derivative Asset FTRs	Derivative Liability FTRs	Net FTRs
		(In millions)	
January 1, 2012 Balance	$ 1	$ (7)	$ (6)
Unrealized gain (loss)	4	(4)	—
Purchases	9	(7)	2
Settlements	(8)	12	4
December 31, 2012 Balance	$ 6	$ (6)	$ —
Unrealized loss	—	(2)	(2)
Purchases	5	(12)	(7)
Settlements	(8)	9	1
December 31, 2013 Balance	$ 3	$ (11)	$ (8)

Level 3 Quantitative Information

The following table provides quantitative information for FTRs held by FES that are classified as Level 3 in the fair value hierarchy for the period ended December 31, 2013:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (8)	Model	RTO auction clearing prices	($2.80) to $5.20	$0.50	Dollars/MWH

INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities, AFS securities and notes receivable.

At the end of each reporting period, FirstEnergy evaluates its investments for OTTI. Investments classified as AFS securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold an equity security until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating an investment for impairment. For debt securities, FirstEnergy considers its intent to hold the securities, the likelihood that it will be required to sell the securities before recovery of its cost basis and the likelihood of recovery of the securities' entire amortized cost basis. If the decline in fair value is determined to be other than temporary, the cost basis of the securities is written down to fair value.

Unrealized gains and losses on AFS securities are recognized in AOCI. However, unrealized losses held in the NDTs of FES, OE and TE are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI.

The investment policy for the NDT funds restricts or limits the trusts' ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, securities convertible into common stock and securities of the trust funds' custodian or managers and their parents or subsidiaries.

AFS Securities

FirstEnergy holds debt and equity securities within its NDT, nuclear fuel disposal and NUG trusts. These trust investments are considered AFS securities, recognized at fair market value. FirstEnergy has no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains (there were no unrealized losses) and fair values of investments held in NDT, nuclear fuel disposal and NUG trusts as of December 31, 2013 and December 31, 2012:

	December 31, 2013[1]			December 31, 2012[2]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	$ 1,881	$ 33	$ 1,914	$ 1,827	$ 34	$ 1,861
FES	918	17	935	778	14	792
Equity securities						
FirstEnergy	$ 308	$ 9	$ 317	$ 293	$ 16	$ 309
FES	207	—	207	281	13	294

(1) Excludes short-term cash investments: FE Consolidated - $204 million; FES - $135 million.
(2) Excludes short-term cash investments: FE Consolidated - $326 million; FES - $196 million.

Proceeds from the sale of investments in AFS securities, realized gains and losses on those sales, OTTI and interest and dividend income for the three years ended December 31, 2013, 2012 and 2011 were as follows:

December 31, 2013	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
			(In millions)		
FirstEnergy	$ 2,047	$ 92	$ (46)	$ (90)	$ 101
FES	940	70	(21)	(79)	60

December 31, 2012	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
			(In millions)		
FirstEnergy	$ 2,980	$ 179	$ (83)	$ (16)	$ 70
FES	1,464	124	(59)	(14)	39

December 31, 2011	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
			(In millions)		
FirstEnergy	$ 4,207	$ 229	$ (71)	$ (19)	$ 82
FES	1,843	80	(29)	(17)	47

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of December 31, 2013 and December 31, 2012:

	December 31, 2013			December 31, 2012		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
			(In millions)			
Debt Securities						
FirstEnergy	$ 33	$ 2	$ 35	$ 54	$ 30	$ 84

Investments in emission allowances, employee benefit trusts and cost and equity method investments, including FirstEnergy's investment in Global Holding, totaling $636 million as of December 31, 2013, and $644 million as of December 31, 2012, are excluded from the amounts reported above.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported as Short-term borrowings on the Consolidated Balance Sheets at cost. Since these borrowings are short-term in nature, FirstEnergy believes that their costs approximate their fair market value. The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations, excluding capital lease obligations and net unamortized premiums and discounts:

	December 31, 2013		December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
FirstEnergy	$ 17,049	$ 17,957	$ 16,957	$ 19,460
FES	3,001	3,073	4,194	4,524

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy and its subsidiaries. FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of December 31, 2013 and December 31, 2012.

10. DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility relating to these exposures, FirstEnergy's Risk Policy Committee, comprised of senior management, provides general management oversight for risk management activities throughout FirstEnergy. The Risk Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy also uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value unless they meet the normal purchases and normal sales criteria. Derivatives that meet those criteria are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance. Changes in the fair value of derivative instruments that qualified and were designated as cash flow hedge instruments are recorded in AOCI. Changes in the fair value of derivative instruments that are not designated as cash flow hedge instruments are recorded in net income on a mark-to-market basis. FirstEnergy has contractual derivative agreements through 2020.

Cash Flow Hedges

FirstEnergy has used cash flow hedges for risk management purposes to manage the volatility related to exposures associated with fluctuating commodity prices and interest rates. The effective portion of gains and losses on a derivative contract is reported as a component of AOCI with subsequent reclassification to earnings in the period during which the hedged forecasted transaction affects earnings.

Total net unamortized gains included in AOCI associated with instruments previously designated to be in a cash flow hedging relationship totaled $2 million and $10 million as of December 31, 2013 and December 31, 2012, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Approximately $10 million is expected to be amortized to income during the next twelve months.

FirstEnergy has used forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. Total unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $59 million and $70 million as of December 31, 2013 and December 31, 2012, respectively. Based on current estimates, approximately $9 million will be amortized to interest expense during the next twelve months.

As of December 31, 2013 and December 31, 2012, no commodity or interest rate derivatives were designated as cash flow hedges.

Refer to Note 2, Accumulated Other Comprehensive Income, for reclassifications from AOCI during the years ended December 31, 2013 and 2012.

Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. These derivative instruments were treated as fair value hedges of fixed-rate, long-term debt issues, protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates.

Unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $44 million and $79 million as of December 31, 2013 and December 31, 2012, respectively. Based on current estimates, approximately $12 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled approximately $19 million and $22 million during the years ended December 31, 2013 and 2012, respectively. In connection with the redemptions of senior notes by FES, PN, and ME and taxable bonds by CEI and OE, unamortized gains associated with fixed for floating interest rate swap agreements of $17 million were included in the Loss on debt redemptions in the Consolidated Statements of Income for the year ended December 31, 2013. Refer to Note 12, Capitalization, for additional information regarding FirstEnergy's debt redemptions during the year ended December 31, 2013. In 2012, FirstEnergy terminated all forward starting swap agreements resulting in cash proceeds and a net gain, recorded as a reduction to interest expense, of approximately $6 million.

As of December 31, 2013 and December 31, 2012, no commodity or interest rate derivatives were designated as fair value hedges.

Commodity Derivatives

FirstEnergy uses both physically and financially settled derivatives to manage its exposure to volatility in commodity prices. Commodity derivatives are used for risk management purposes to hedge exposures when it makes economic sense to do so, including circumstances where the hedging relationship does not qualify for hedge accounting.

Electricity forwards are used to balance expected sales with expected generation and purchased power. Natural gas futures are entered into based on expected consumption of natural gas primarily for use in FirstEnergy's combustion turbine units. Derivative instruments are not used in quantities greater than forecasted needs.

As of December 31, 2013, FES' net asset position under commodity derivative contracts was $102 million. Under these commodity derivative contracts, FES posted $29 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $1 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on commodity derivative contracts held as of December 31, 2013, an adverse change of 10% in commodity prices would decrease net income by approximately $27 million during the next twelve months.

NUGs

As of December 31, 2013, FirstEnergy's net liability position under NUG contracts was $202 million representing contracts held at JCP&L, ME and PN. NUG contracts represent purchased power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. Changes in the fair value of NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

LCAPP

The LCAPP law was enacted in New Jersey during 2011 to promote the construction of qualified electric generation facilities. JCP&L maintained two LCAPP contracts, which are financially settled agreements that allow eligible generators to receive payments from, or make payments to, JCP&L pursuant to an annually calculated load-ratio share of the capacity produced by the generator based upon the annual forecasted peak demand as determined by PJM. JCP&L expected to recover from its customers payments made to the generators and give credit to customers for payments from the generators under these contracts. As a result, the projected future obligations for the LCAPP contracts are considered derivative liabilities with a corresponding regulatory asset. Since the LCAPP contracts were subject to regulatory accounting, changes in their fair value did not impact earnings. On October 11, 2013, the U.S. District Court for the District of New Jersey declared that the LCAPP is preempted by the FPA and unconstitutional. On October 22, 2013, the Superior Court of New Jersey Appellate Division dismissed two consolidated appeals which had been taken from the final order of the NJBPU which accepted and adopted the recommendation of the NJBPU's Agent regarding implementation of the LCAPP law. Dismissal of the consolidated appeals, along with pending matters currently on remand to the NJBPU, was without prejudice subject to the parties exercising their appellate rights in the federal courts. The parties filed an appeal with the U.S. Court of Appeals for the Third Circuit with briefing by the parties to be completed by March 5, 2014. Consistent with the provisions of the LCAPP contracts, the U.S District Court's ruling is a termination event. During the fourth quarter of 2013, JCP&L issued termination notices to the counterparties and reversed the derivative liability and corresponding regulatory asset on its Consolidated Balance Sheet.

FTRs

As of December 31, 2013, FirstEnergy's and FES' net liability position under FTRs was $8 million and FES posted $5 million of collateral. FirstEnergy holds FTRs that generally represent an economic hedge of future congestion charges that will be incurred in connection with FirstEnergy's load obligations. FirstEnergy acquires the majority of its FTRs in an annual auction through a self-scheduling process involving the use of ARRs allocated to members of an RTO that have load serving obligations and through the direct allocation of FTRs from the PJM RTO. The PJM RTO has a rule that allows directly allocated FTRs to be granted to LSEs in zones that have newly entered PJM. For the first two planning years, PJM permits the LSEs to request a direct allocation of FTRs in these new zones at no cost as opposed to receiving ARRs. The directly allocated FTRs differ from traditional FTRs in that the ownership of all or part of the FTRs may shift to another LSE if customers choose to shop with the other LSE.

The future obligations for the FTRs acquired at auction are reflected on the Consolidated Balance Sheets and have not been designated as cash flow hedge instruments. FirstEnergy initially records these FTRs at the auction price less the obligation due to the RTO, and subsequently adjusts the carrying value of remaining FTRs to their estimated fair value at the end of each accounting period prior to settlement. Changes in the fair value of FTRs held by FES and AE Supply are included in other operating expenses as unrealized gains or losses. Unrealized gains or losses on FTRs held by FirstEnergy's utilities are recorded as regulatory assets or liabilities. Directly allocated FTRs are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance.

FirstEnergy records the fair value of derivative instruments on a gross basis. The following table summarizes the fair value and classification of derivative instruments on FirstEnergy's Consolidated Balance Sheets:

Derivative Assets			Derivative Liabilities		
	Fair Value			Fair Value	
	December 31, 2013	December 31, 2012		December 31, 2013	December 31, 2012
	(In millions)			*(In millions)*	
Current Assets - Derivatives			**Current Liabilities - Derivatives**		
Commodity Contracts	$ 162	$ 153	Commodity Contracts	$ (102)	$ (119)
FTRs	4	7	FTRs	(9)	(7)
	166	160		(111)	(126)
			Noncurrent Liabilities - Adverse Power Contract Liability		
			NUGs	(222)	(290)
Deferred Charges and Other Assets - Other			LCAAP	—	(144)
			Noncurrent Liabilities - Other		
Commodity Contracts	53	99			
FTRs	—	1	Commodity Contracts	(11)	(36)
NUGs	20	36	FTRs	(3)	(2)
	73	136		(236)	(472)
Derivative Assets	$ 239	$ 296	Derivative Liabilities	$ (347)	$ (598)

FirstEnergy enters into contracts with counterparties that allow for net settlement of derivative assets and derivative liabilities. Certain of these contracts contain margining provisions that require the use of collateral to mitigate credit exposure between FirstEnergy and these counterparties. In situations where collateral is pledged to mitigate exposures related to derivative and non-derivative instruments with the same counterparty, FirstEnergy allocates the collateral based on the percentage of the net fair value of derivative instruments to the total fair value of the combined derivative and non-derivative instruments. The following tables summarize the fair value of derivative instruments on FirstEnergy's Consolidated Balance Sheets and the effect of netting arrangements and collateral on its financial position:

		Amounts Not Offset in Consolidated Balance Sheet		
December 31, 2013	Fair Value	Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
		(In millions)		
Derivative Assets				
Commodity contracts	$ 215	$ (106)	$ (9)	$ 100
FTRs	4	(4)	—	—
NUG contracts	20	—	—	20
	$ 239	$ (110)	$ (9)	$ 120
Derivative Liabilities				
Commodity contracts	$ (113)	$ 106	$ 7	$ —
FTRs	(12)	4	5	(3)
NUG contracts	(222)	—	—	(222)
	$ (347)	$ 110	$ 12	$ (225)

December 31, 2012	Fair Value	Amounts Not Offset in Consolidated Balance Sheet		Net Fair Value
		Derivative Instruments	Cash Collateral (Received)/Pledged	
		(In millions)		
Derivative Assets				
Commodity contracts	$ 252	$ (142)	$ (5)	$ 105
FTRs	8	(8)	—	—
NUG contracts	36	—	—	36
	$ 296	$ (150)	$ (5)	$ 141
Derivative Liabilities				
Commodity contracts	$ (155)	$ 142	$ 12	$ (1)
FTRs	(9)	8	1	—
NUG contracts	(290)	—	—	(290)
LCAPP contracts	(144)	—	—	(144)
	$ (598)	$ 150	$ 13	$ (435)

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of December 31, 2013:

	Purchases	Sales	Net	Units
		(In millions)		
Power Contracts	34	37	(3)	MWH
FTRs	43	—	43	MWH
NUGs	11	—	11	MWH
Natural Gas	77	3	74	mmBTU

The effect of derivative instruments not in a hedging relationship on the Consolidated Statements of Income during 2013 and 2012 are summarized in the following tables:

	Year Ended December 31			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2013				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense	$ 11	$ (8)	$ —	$ 3
Realized Gain (Loss) Reclassified to:				
Revenues	$ 46	$ 21	$ —	$ 67
Purchased Power Expense	(38)	—	—	(38)
Other Operating Expense	—	(36)	—	(36)
Fuel Expense	(2)	—	—	(2)
2012				
Unrealized Gain Recognized in:				
Other Operating Expense	$ 89	$ 13	$ —	$ 102
Realized Gain (Loss) Reclassified to:				
Revenues	$ 302	$ 22	$ —	$ 324
Purchased Power Expense	(277)	—	—	(277)
Other Operating Expense	—	(61)	—	(61)
Fuel Expense	5	—	—	5
Interest Expense	—	—	6	6

The unrealized and realized gains (losses) on FirstEnergy's derivative instruments subject to regulatory accounting during 2013 and 2012 are summarized in the following table:

	Year Ended December 31			
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	LCAPP	Regulated FTRs	Total
	(In millions)			
2013				
Unrealized Gain (Loss) on Derivative Instrument	$ (23)	$ (22)	$ 1	$ (44)
Realized Gain (Loss) on Derivative Instrument	75	166	(1)	240
2012				
Unrealized Gain (Loss) on Derivative Instrument	$ (201)	$ (144)	$ 1	$ (344)
Realized Gain on Derivative Instrument	240	—	7	247

The following table provides a reconciliation of changes in the fair value of certain contracts that are deferred for future recovery from (or credit to) customers during 2013 and 2012:

Derivatives Not in a Hedging Relationship with Regulatory Offset	Year Ended December 31			
	NUGs	LCAPP	Regulated FTRs	Total
		(In millions)		
Outstanding net liability as of January 1, 2013	$ (254)	$ (144)	$ —	$ (398)
Additions/Change in value of existing contracts	(23)	(22)	1	(44)
Settled contracts	75	166	(1)	240
Outstanding net liability as of December 31, 2013	$ (202)	$ —	$ —	$ (202)
Outstanding net liability as of January 1, 2012	$ (293)	$ —	$ (8)	$ (301)
Additions/Change in value of existing contracts	(201)	(144)	1	(344)
Settled contracts	240	—	7	247
Outstanding net liability as of December 31, 2012	$ (254)	$ (144)	$ —	$ (398)

11. IMPAIRMENT OF LONG-LIVED ASSETS

FirstEnergy reviews long-lived assets, including regulatory assets, for impairment whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The recoverability of a long-lived asset is measured by comparing its carrying value to the sum of undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is greater than the undiscounted cash flows, an impairment exists and a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. FirstEnergy utilizes the income approach, based upon discounted cash flows to estimate fair value.

West Virginia Asset Transfer - 2013

On October 9, 2013, MP sold its approximate 8% share of Pleasants at its fair market value of $73 million to AE Supply, and AE Supply sold its approximate 80% share of Harrison to MP at its book value of $1.2 billion. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. The $1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately $527 million and a note payable to AE Supply of approximately $573 million. The note payable to AE Supply was repaid in the fourth quarter of 2013. In connection with the closing, in the fourth quarter of 2013, MP recorded a pre-tax impairment charge of approximately $322 million to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. Additionally, MP recognized a regulatory liability of approximately $23 million in the fourth quarter of 2013 representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station.

Generating Plant Retirements - 2013

On July 8, 2013, officers of FirstEnergy and AE Supply committed to deactivating the following generating units by October 9, 2013:

Generating Units	MW Capacity	Location
Hatfield's Ferry, Units 1-3	1,710	Masontown, Pennsylvania
Mitchell, Units 2-3	370	Courtney, Pennsylvania

As a result of this decision, in the second quarter of 2013, FirstEnergy recorded a pre-tax impairment of approximately $473 million to continuing operations, which also includes pre-tax impairments of $13 million related to excessive inventory at these facilities. The impairment charge is included within the results of the Competitive Energy Services segment. On October 9, 2013, Hatfield's Ferry Units 1-3 and Mitchell Units 2-3 were deactivated.

Approximately 240 plant employees and generation related positions were affected by these plant deactivations. FirstEnergy recorded approximately $6 million (pre-tax) severance related expenses that were recognized in Other operating expenses in the Consolidated Statements of Income during the year ended 2013.

AE Supply has obligations, such as fuel supply, that could be affected by the plant deactivations and management is currently unable to reasonably estimate potential costs, or a range thereof, that could be incurred.

Generating Plant Retirements - 2011

On January 26, 2012 and February 8, 2012, FG, MP and AE Supply announced the deactivation by September 1, 2012 (subject to a reliability review by PJM) of nine coal-fired power plants (Albright, Armstrong, Ashtabula, Bay Shore except for generating unit 1, Eastlake, Lakeshore, R. Paul Smith, Rivesville and Willow Island) with a total capacity of 3,349 MW due to MATS and other environmental regulations. As a result of this decision, FirstEnergy recorded a pre-tax impairment of $334 million to continuing

operations during the year ended 2011. This impairment consisted of a $311 million write down of the carrying value of the plant assets, approximately $5 million in excessive SO_2 emission allowances and an $18 million charge for excessive or obsolete inventory at these facilities. On April 25, 2012, PJM concluded its initial analysis of the reliability impacts from the previously announced plant deactivations and requested RMR arrangements for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015. In February 2014, PJM notified FirstEnergy that Eastlake Units 1-3 and Lake Shore Unit 18 will be released from RMR status as of September 15, 2014. On July 10, 2012, and as amended on October 31, 2012, FirstEnergy filed with FERC, for informational purposes, the compensation arrangements for these units which will remain in effect for as long as these generating units continue to operate. As of September 1, 2012, Albright, Armstrong, Bay Shore (except for generating unit 1), Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island were deactivated. During the year ended December 31, 2012, FirstEnergy recognized pre-tax severance expense of approximately $14 million ($10 million by FES) as a result of the deactivations. These costs are included in "other operating expenses" in the Consolidated Statements of Income.

In addition to the emission allowance impairments in connection with the plant closures, FirstEnergy recorded during 2011, pre-tax impairment charges of approximately $6 million ($1 million for FES and $5 million for AE Supply) for NOx emission allowances that were expected to be obsolete after 2011 and approximately $16 million ($13 million for FES and $3 million for AE Supply) for excess SO_2 emission allowances in inventory that it expected will not be consumed in the future.

Fremont Energy Center

On March 11, 2011, FirstEnergy and American Municipal Power, Inc., entered into an agreement for the sale of Fremont Energy Center, which included two natural gas combined-cycle combustion turbines and a steam turbine capable of producing 544 MW of load-following capacity and 163 MW of peaking capacity. The execution of this agreement triggered a need to evaluate the recoverability of the carrying value of the assets associated with the Fremont Energy Center. The estimated fair value of the Fremont Energy Center was based on the purchase price outlined in the sale agreement with American Municipal Power, Inc. The result of this evaluation indicated that the carrying cost of the Fremont Energy Center was not fully recoverable. As a result of the recoverability evaluation, FirstEnergy recorded an impairment charge of $11 million to operating income in the first quarter of 2011. On July 28, 2011, FirstEnergy completed the sale of Fremont Energy Center to American Municipal Power, Inc.

Peaking Facilities

During 2011, FirstEnergy assessed the carrying values of certain peaking facilities that were to be sold or disposed of before the end of their useful lives. The estimated fair values were based on estimated sales prices quoted in an active market and indicated that the carrying costs of the peaking facilities were not fully recoverable. FirstEnergy recorded impairment charges of $23 million during 2011 and on October 18, 2011, FirstEnergy closed on the sale of the Richland and Stryker peaking facilities.

12. CAPITALIZATION

COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2013, FirstEnergy's unrestricted retained earnings were $2.6 billion. Dividends declared in 2013 were $1.65 per share, which included dividends of $0.55 per share paid in the second, third and fourth quarters of 2013. Dividends declared in 2012 were $2.20 per share, which included dividends of $0.55 per share paid in the second, third and fourth quarter of 2012 and dividends of $0.55 per share paid in the first quarter of 2013. The amount and timing of all dividend declarations are subject to the discretion of the Board of Directors and its consideration of business conditions, results of operations, financial condition and other factors. On January 21, 2014 the Board of Directors declared a quarterly dividend of $0.36 per share to be paid in the first quarter of 2014.

In addition to paying dividends from retained earnings, OE, CEI, TE, Penn, JCP&L, ME and PN have authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as their FERC-defined equity to total capitalization ratio remains above 35%. In addition, TrAIL and AGC have authorization from the FERC to pay cash dividends to FE from paid-in capital accounts, as long as their FERC-defined equity to total capitalization ratio remains above 50% and 45%, respectively. The articles of incorporation, indentures, regulatory limitations and various other agreements relating to the long-term debt of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. None of these provisions materially restricted FirstEnergy's subsidiaries' abilities to pay cash dividends to FirstEnergy as of December 31, 2013.

SIP/DRIP Program

On September 25, 2013, FE filed a registration statement with the SEC to register 4 million shares of common stock to be issued to registered shareholders and its employees and the employees of its subsidiaries under its Stock Investment Plan. In addition, during December 2013, FE began fulfilling certain share-based benefit plan obligations through the issuance of authorized but unissued common stock.

PREFERRED AND PREFERENCE STOCK

FirstEnergy and the Utilities were authorized to issue preferred stock and preference stock as of December 31, 2013, as follows:

	Preferred Stock		Preference Stock	
	Shares Authorized	Par Value	Shares Authorized	Par Value
FirstEnergy	5,000,000	$ 100		
OE	6,000,000	$ 100	8,000,000	no par
OE	8,000,000	$ 25		
Penn	1,200,000	$ 100		
CEI	4,000,000	no par	3,000,000	no par
TE	3,000,000	$ 100	5,000,000	$ 25
TE	12,000,000	$ 25		
JCP&L	15,600,000	no par		
ME	10,000,000	no par		
PN	11,435,000	no par		
MP	940,000	$ 100		
PE	10,000,000	$ 0.01		
WP	32,000,000	no par		

As of December 31, 2013, and 2012, there were no preferred or preference shares outstanding.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

The following tables present outstanding long-term debt and capital lease obligations for FirstEnergy and FES as of December 31, 2013 and 2012:

	As of December 31, 2013		As of December 31	
(Dollar amounts in millions)	**Maturity Date**	**Interest Rate**	**2013**	**2012**
FirstEnergy:				
FMBs	2014 - 2043	3.340% - 9.740%	$ 3,166	$ 2,587
Secured notes - fixed rate	2017 - 2037	6.150% - 7.880%	1,804	2,113
Secured notes - variable rate			—	50
Total secured notes			1,804	2,163
Unsecured notes - fixed rate	2014 - 2039	3.500% - 7.350%	11,076	11,145
Unsecured notes - variable rate	2014 - 2015	0.020% - 1.665%	959	959
Total unsecured notes			12,035	12,104
Capital lease obligations			188	176
Unamortized debt premiums			9	45
Unamortized fair value adjustments			44	103
Currently payable long-term debt			(1,415)	(1,999)
Total long-term debt and other long-term obligations			$ 15,831	$ 15,179
FES:				
Secured notes - fixed rate	2015 - 2017	5.150% - 12.000%	$ 188	$ 689
Secured notes - variable rate			—	50
Total secured notes			188	739
Unsecured notes - fixed rate	2014 - 2039	2.150% - 6.800%	2,077	2,769
Unsecured notes - variable rate	2014 - 2015	0.130% - 0.160%	736	686
Total unsecured notes			2,813	3,455
Capital lease obligations			22	27
Unamortized debt discounts			(1)	(1)
Currently payable long-term debt			(892)	(1,102)
Total long-term debt and other long-term obligations			$ 2,130	$ 3,118

On March 5, 2013, FE issued in aggregate $1.5 billion of senior unsecured notes in two series: $650 million of 2.75% senior notes due March 15, 2018 and $850 million of 4.25% senior notes due March 15, 2023. The stated interest rates are subject to adjustments based upon changes in the credit ratings of FirstEnergy but will not decrease below the issued rates. The proceeds were used to repay short-term borrowings and to invest in the money pool for FES and AE Supply's use in funding a portion of their concurrent tender offers.

On March 28, 2013, pursuant to tender offers launched in February 2013, FES and AE Supply repurchased $369 million and $294 million, respectively, of outstanding senior notes with interest rates ranging from 5.75% to 6.8%. The $369 million of FES repurchases consisted of original maturities of $252 million due 2021 and $117 million due 2039. The $294 million of AE Supply repurchases consisted of original maturities of $194 million due 2019 and $100 million due 2039. FES and AE Supply paid $67 million and $43 million, respectively, in tender premiums to repurchase the tendered senior notes. FirstEnergy recorded a loss on debt redemption of $119 million (FES - $71 million), including such premiums and other related expenses. The tender premiums paid are included in cash flows from financing activities in the Consolidated Statement of Cash Flows.

In March 2013, ME issued $300 million of 3.50% senior unsecured notes due March 15, 2023. Proceeds from this offering were used to repay $150 million of ME 4.95% senior unsecured notes that matured in March 2013 and short-term borrowings.

On April 15, 2013, FES redeemed $400 million of its 4.80% senior notes due 2015 and recorded a loss on debt redemption of $32 million including $31 million of make-whole premiums paid. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

On May 8, 2013, FE, FES, AE Supply and FE's other borrowing subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. The FE Facility was amended to increase the lending

banks' commitments under the facility by $500 million to a total of $2.5 billion and to increase the individual borrower sub-limits for FE by $500 million to a total of $2.5 billion and for JCP&L by $175 million to a total of $600 million.

On June 3, 2013, FG exercised a mandatory put option and repurchased approximately $235 million of PCRBs due 2023, which FG is currently holding for remarketing subject to future market and other conditions.

As discussed in Note 8, Variable Interest Entities, in June 2013, the SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds with a weighted average coupon of 2.48% to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds were sold to a trust that concurrently sold a like aggregate amount of its pass through trust certificates to public investors. The proceeds were primarily used to redeem $410 million in existing taxable bonds of the Ohio Companies with a weighted average coupon of 5.71%, including $30 million of make-whole premiums. The securitization effectively allows for the recovery of the make-whole premiums and transactional costs through the imposition of non-bypassable phase-in recovery charges on retail electric customers of the Ohio Companies pursuant to Ohio law. The $410 million of redemption consisted of original maturities of $225 million due 2013, $150 million due 2015 and $35 million due 2020. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows.

During August, the Ohio Companies redeemed an additional $660 million of long-term debt with interest rates ranging from 5.65% to 7.25% and paid approximately $120 million of make-whole premiums which were deferred as a regulatory asset and will be amortized over the original life of the redeemed debt. The make-whole premiums paid are included in cash flows from operating activities in the Consolidated Statement of Cash Flows. Additionally, during August, JCP&L issued $500 million of 4.7% unsecured notes due April 2024 and used the proceeds to pay down a portion of its short-term debt obligations.

On November 15, 2013, AE Supply optionally redeemed $235 million of its 7.00% PCRBs due July 15, 2039 at 100% of the principal amount in connection with the deactivation of operations at Hatfield's Ferry.

On November 27, 2013, MP issued $400 million of 4.10% FMBs due April 15, 2024 and $600 million of 5.40% FMBs due December 15, 2043. Proceeds from this offering were used by MP to: (i) repay at maturity $300 million of its FMBs, 7.95% Series due December 15, 2013; (ii) redeem $120 million of its FMBs, 6.70% Series due June 15, 2014; (iii) repay a $572.7 million short-term promissory note originally issued on October 9, 2013 to its affiliate, AE Supply in connection with MP’s acquisition of the remaining ownership of the Harrison Power Station; and (iv) for working capital needs and other general corporate purposes.

During December of 2013, FE entered into an agreement to extend and amend its $150 million term loan agreement with a maturity date of December 31, 2014. The maturity of the loan was extended to December 31, 2015 and the principal amount was increased to $200 million. On December 26, 2013, PN redeemed $150 million of its 5.13% Senior Notes due April 1,2014 and ME redeemed $100 million of its 4.88% Senior Notes due April 1, 2014.

See Note 6, Leases for additional information related to capital leases.

Securitized Bonds

Environmental Control Bonds

The consolidated financial statements of FirstEnergy include environmental control bonds issued by two bankruptcy remote, special purpose limited liability companies that are indirect subsidiaries of MP and PE. Proceeds from the bonds were used to construct environmental control facilities. The special purpose limited liability companies own the irrevocable right to collect non-bypassable environmental control charges from all customers who receive electric delivery service in MP's and PE's West Virginia service territories. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. The right to collect environmental control charges is not included as an asset on FirstEnergy's consolidated balance sheets. Creditors of FirstEnergy, other than the special purpose limited liability companies, have no recourse to any assets or revenues of the special purpose limited liability companies. As of December 31, 2013 and 2012, $472 million and $493 million of environmental control bonds were outstanding, respectively.

Transition Bonds

The consolidated financial statements of FirstEnergy and JCP&L include the accounts of JCP&L Transition Funding and JCP&L Transition Funding II, wholly owned limited liability companies of JCP&L. In June 2002, JCP&L Transition Funding sold transition bonds to securitize the recovery of JCP&L’s bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station. In August 2006, JCP&L Transition Funding II sold transition bonds to securitize the recovery of deferred costs associated with JCP&L’s supply of BGS. JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy’s and JCP&L’s Consolidated Balance Sheets. The transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company’s equity and assets, which consist primarily of bondable transition property. As of December 31, 2013 and 2012, $207 million and $243 million of the transition bonds were outstanding, respectively.

Bondable transition property represents the irrevocable right under New Jersey law of a utility company to charge, collect and receive from its customers, through a non-bypassable TBC, the principal amount and interest on transition bonds and other fees and expenses associated with their issuance. JCP&L sold its bondable transition property to JCP&L Transition Funding and JCP&L Transition Funding II and, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the TBC, pursuant to separate servicing agreements with JCP&L Transition Funding and JCP&L Transition Funding II. For the two series of transition bonds, JCP&L is entitled to aggregate annual servicing fees of up to $628 thousand that are payable from TBC collections.

Phase-In Recovery Bonds

In June 2013, the SPEs formed by the Ohio Companies issued approximately $445 million of pass-through trust certificates supported by phase-in recovery bonds with a weighted average coupon of 2.48% to securitize the recovery of certain all electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds were sold to a trust that concurrently sold a like aggregate amount of its pass through trust certificates to public investors.

Other Long-term Debt

The Ohio Companies, Penn, FG and NG each have a first mortgage indenture under which they can issue FMBs secured by a direct first mortgage lien on substantially all of their property and franchises, other than specifically excepted property.

Based on the amount of FMBs authenticated by the respective mortgage bond trustees as of December 31, 2013, the sinking fund requirement for all FMBs issued under the various mortgage indentures amounted to payments of $7 million in 2013, all of which relate to Penn. Penn expects to meet its 2013 annual sinking fund requirement with a replacement credit under its mortgage indenture.

As of December 31, 2013, FirstEnergy's currently payable long-term debt included approximately $809 million (FES — $736 million) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds, or if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

The following table presents scheduled debt repayments for outstanding long-term debt, excluding capital leases, fair value purchase accounting adjustments and unamortized debt discounts and premiums, for the next five years as of December 31, 2013. PCRBs that can be tendered for mandatory purchase prior to maturity are reflected in 2014.

Year	FirstEnergy	FES
	(In millions)	
2014	$ 1,376	$ 887
2015	1,264	391
2016	1,041	417
2017	1,641	163
2018	1,453	266

The following table classifies the outstanding fixed rate put PCRBs and variable rate PCRBs by year, excluding unamortized debt discounts and premiums, for the next five years based on the next date on which the debt holders may exercise their right to tender their PCRBs.

Year	FirstEnergy	FES
	(In millions)	
2014	$ 835	$ 762
2015	313	313
2016	391	391
2017	130	130
2018	125	125

Obligations to repay certain PCRBs are secured by several series of FMBs. Certain PCRBs are entitled to the benefit of irrevocable bank LOCs, to pay principal of, or interest on, the applicable PCRBs. To the extent that drawings are made under the LOCs, FG, NG and the applicable Utilities are entitled to a credit against their obligation to repay those bonds. FG, NG and the applicable Utilities pay annual fees based on the amounts of the LOCs to the issuing banks and are obligated to reimburse the banks or insurers, as the case may be, for any drawings thereunder. The insurers hold FMBs as security for such reimbursement obligations.

The amounts and annual fees for PCRB-related LOCs for FirstEnergy and FES as of December 31, 2013, are as follows:

	Aggregate LOC Amount	Annual Fees
	(In millions)	
FirstEnergy	$ 818	1.65% to 3.30%
FES	744	1.65% to 3.30%

Debt Covenant Default Provisions

FirstEnergy has various debt covenants under certain financing arrangements, including its revolving credit facilities. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on such debt and the maintenance of certain financial ratios. The failure by FirstEnergy to comply with the covenants contained in its financing arrangements could result in an event of default, which may have an adverse effect on its financial condition. As of December 31, 2013, FirstEnergy and FES remain in compliance with all debt covenant provisions.

Additionally, there are cross-default provisions in a number of the financing arrangements. These provisions generally trigger a default in the applicable financing arrangement of an entity if it or any of its significant subsidiaries default under another financing arrangement in excess of a certain principal amount, typically $100 million. Although such defaults by any of the Utilities, ATSI or TrAIL would generally cross-default FirstEnergy financing arrangements containing these provisions, defaults by any of AE Supply, FES, FG or NG would generally not cross-default to applicable financing arrangements of FirstEnergy. Also, defaults by FirstEnergy would generally not cross-default applicable financing arrangements of any of FirstEnergy's subsidiaries. Cross-default provisions are not typically found in any of the senior notes or FMBs of FirstEnergy, FG, NG or the Utilities.

13. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FirstEnergy had $3,404 million and $1,969 million of short-term borrowings as of December 31, 2013 and December 31, 2012, respectively. FirstEnergy's available liquidity as of January 31, 2014, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[(1)]	Revolving	May 2018	$ 2,500	$ 224
FES / AE Supply	Revolving	May 2018	2,500	2,489
FET[(2)]	Revolving	May 2018	1,000	—
		Subtotal	$ 6,000	$ 2,713
		Cash	—	48
		Total	$ 6,000	$ 2,761

(1) FE and the Utilities
(2) Includes FET, ATSI and TrAIL as subsidiary borrowers

Revolving Credit Facilities

FirstEnergy, FES/AE Supply and FET Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities). The Facilities consist of a $2.5 billion aggregate FirstEnergy Facility, a $2.5 billion FES/AE Supply Facility and a $1.0 billion FET Facility, that are each available until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended.

On May 8, 2013, FE, FES, AE Supply and FE's other borrowing subsidiaries entered into extensions and amendments to the three existing multi-year syndicated revolving credit facilities. Each facility was extended until May 2018, unless the lenders agree, at the request of the applicable borrowers, to an additional one-year extension. The FE Facility was amended to increase the lending banks' commitments under the facility by $500 million to a total of $2.5 billion and to increase the individual borrower sub-limits for FE by $500 million to a total of $2.5 billion and for JCP&L by $175 million to a total of $600 million.

On October 31, 2013, FE amended its existing $2.5 billion multi-year syndicated revolving credit facility to exclude certain after-tax, non-cash write-downs and non-cash charges of approximately $1.4 billion (primarily related to Pension and OPEB mark-to-market adjustments, impairment of long-lived assets and regulatory charges) from the debt to total capitalization ratio calculations incurred through September 30, 2013. Additionally, the amendment provides for a future allowance of approximately $1.35 billion for after-tax, non-cash write-downs and non-cash charges over the remaining life of the facility. Similarly, the FES/AE Supply $2.5 billion revolving credit facility was also amended to exclude certain similar after-tax, non-cash write-downs and non-cash charges of $785.7 million incurred through September 30, 2013 from the debt to total capitalization ratio calculations. As of December 31, 2013, the borrowers were in compliance with the applicable debt to total capitalization ratios under the respective Facilities.

The following table summarizes the borrowing sub-limits for each borrower under the Facilities, the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations, as of December 31, 2013:

Borrower	Revolving Credit Facility Sub-Limits	Regulatory and Other Short-Term Debt Limitations
	(In millions)	
FE	$ 2,500	$ — [1]
FES	1,500	— [2]
AE Supply	1,000	— [2]
FET	1,000	— [1]
OE	500	500 [3]
CEI	500	500 [3]
TE	500	500 [3]
JCP&L	600	850 [3]
ME	300	500 [3]
PN	300	300 [3]
WP	200	200 [3]
MP	150	500 [3]
PE	150	150 [3]
ATSI	100	500 [3]
Penn	50	50 [3]
TrAIL	200	400 [3]

(1) No limitations.
(2) No limitation based upon blanket financing authorization from the FERC under existing market-based rate tariffs.
(3) Excluding amounts which may be borrowed under the regulated companies' money pool.

The entire amount of the FES/AE Supply Facility, $700 million of the FirstEnergy Facility and $225 million of the FET Facility, subject to each borrower's sub-limit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower's borrowing sub-limit.

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in "pricing grids," whereby the cost of funds borrowed under the Facilities is related to the credit ratings of the company borrowing the funds, other than the FET Facility, which is based on its subsidiaries' credit ratings. Additionally, borrowings under each of the Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million.

Term Loan

During December of 2013, FE entered into an agreement to extend and amend its $150 million term loan agreement with a maturity date of December 31, 2014. The maturity of the loan was extended to December 31, 2015 and the principal amount was increased to $200 million.

FirstEnergy Money Pools

FirstEnergy's regulated companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings during 2013 was 0.67% per annum for the regulated companies' money pool and 1.34% per annum for the unregulated companies' money pool.

Weighted Average Interest Rates

The weighted average interest rates on short-term borrowings outstanding, including borrowings under the FirstEnergy Money Pools, as of December 31, 2013 and 2012, were as follows:

	2013	2012
FirstEnergy	1.80%	1.97%

14. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost primarily for nuclear power plant decommissioning, reclamation of sludge disposal ponds, closure of coal ash disposal sites, underground and above-ground storage tanks, wastewater treatment lagoons and transformers containing PCBs. In addition, FirstEnergy has recognized conditional retirement obligations, primarily for asbestos remediation.

The ARO liabilities for FES primarily relate to the decommissioning of the Beaver Valley, Davis-Besse and Perry nuclear generating facilities. FES uses an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

FirstEnergy and FES maintain NDTs that are legally restricted for purposes of settling the nuclear decommissioning ARO. The fair values of the decommissioning trust assets as of December 31, 2013 and 2012 were as follows:

	2013	2012
	(In millions)	
FirstEnergy	$ 2,201	$ 2,204
FES	$ 1,276	$ 1,283

Conditional retirement obligations associated with tangible long-lived assets are recognized at fair value in the period in which they are incurred if a reasonable estimate can be made, even though there may be uncertainty about timing or method of settlement. When settlement is conditional on a future event occurring, it is reflected in the measurement of the liability, not in the recognition of the liability.

The following table summarizes the changes to the ARO balances during 2013 and 2012:

ARO Reconciliation	FirstEnergy	FES
	(In millions)	
Balance, January 1, 2012	$ 1,497	$ 904
Liabilities settled	(2)	(1)
Accretion	104	62
Balance, December 31, 2012	$ 1,599	$ 965
Liabilities settled	(18)	(18)
Accretion	115	71
Revisions in estimated cash flows	(18)	(3)
Balance, December 31, 2013	$ 1,678	$ 1,015

During 2013, revisions to estimated cash flows as a result of increased cost estimates for the closure of LBR increased the associated ARO liability of FES by $163 million. The revised cost estimates were the result of a Closure Plan submitted to the PA DEP by FG on March 28, 2013, which provides for placing a final cap over LBR, and a response to a technical deficiency letter issued by the PA DEP on October 3, 2013. See Note 16, Commitments, Guarantees, and Contingencies for additional information related to the closure of LBR.

During the third quarter of 2013, studies were completed to update the estimated cost of asbestos remediation for FES and TE. The cost studies resulted in a revision to the estimated cash flows associated with the ARO liabilities of FES and TE and increased the liability for FES and TE by approximately $5 million and $7 million, respectively.

During the fourth quarter of 2013, revisions to estimated nuclear decommissioning cash flows associated with the ARO liability of FES, OE and TE decreased the liability by $171 million, $15 million and $7 million, respectively. The revision in estimates for the ARO balances is the result of a decommissioning study that was completed by a third-party in connection with Davis-Besse's license renewal that was submitted to the NRC in February 2014. The most significant revision from this study was related to accelerating the expected date when the DOE would begin to accept spent fuel, to be more in line with the industry assumptions. Additionally, FirstEnergy also updated and revised its estimates for Perry and Beaver Valley Units 1 and 2, in a consistent manner.

15. REGULATORY MATTERS

STATE REGULATION

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the states in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC. The transmission operations of PE in Virginia are subject to certain regulations of the VSCC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

As competitive retail electric suppliers serving retail customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, FES and AE Supply are subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES, AE Supply and their public utility affiliates. In addition, if FES, AE Supply or any of their subsidiaries were to engage in the construction of significant new generation facilities in any of those states, they would also be subject to state siting authority.

MARYLAND

PE provides SOS pursuant to a combination of settlement agreements, MDPSC orders and regulations, and statutory provisions. SOS supply is competitively procured in the form of rolling contracts of varying lengths through periodic auctions that are overseen by the MDPSC and a third party monitor. Although settlements with respect to residential SOS for PE customers expired on December 31, 2012, by statute, service continues in the same manner unless changed by order of the MDPSC. The settlement provisions relating to non-residential SOS have also expired; however, by MDPSC order, the terms of service remain in place unless PE requests or the MDPSC orders a change. PE recovers its costs plus a return for providing SOS.

The Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals to reduce electric consumption by 10% and reduce electricity demand by 15%, in each case by 2015. PE's initial plan submitted in compliance with the statute was approved in 2009 and covered 2009-2011, the first three years of the statutory period. Expenditures were originally estimated to be approximately $101 million for the PE programs for the entire period of 2009-2015. Meanwhile, after extensive meetings with the MDPSC Staff and other stakeholders, on August 31, 2011, PE filed a new comprehensive plan for the second three year period, 2012-2014, that includes additional and improved programs. The 2012-2014 plan is expected to cost approximately $66 million out of the original $101 million estimate for the entire EmPOWER program. On December 22, 2011, the MDPSC issued an order approving PE's second plan with various modifications and follow-up assignments. PE continues to recover program costs subject to a five-year amortization. Maryland law only allows for the utility to recover lost distribution revenue attributable to energy efficiency or demand reduction programs through a base rate case proceeding, and to date such recovery has not been sought or obtained by PE.

Pursuant to a bill passed by the Maryland legislature in 2011, the MDPSC adopted rules, effective May 28, 2012, that create specific requirements related to a utility's obligation to address service interruptions, downed wire response, customer communication, vegetation management, equipment inspection, and annual reporting. The MDPSC will be required to assess each utility's compliance with the new rules, and may assess penalties of up to $25,000 per day, per violation. The new rules set utility-specific SAIDI and SAIFI targets for 2012-2015; prescribe detailed tree-trimming requirements, outage restoration and downed wire response deadlines; and impose other reliability and customer satisfaction requirements. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately $106 million over the period 2012-2015. On April 1, 2013, the Maryland electric utilities, including PE, filed their first annual reports on compliance with the new rules. The MDPSC conducted a hearing on August 20, 2013 to discuss the reports, after which an order was issued on September 3, 2013, which accepted PE's filing and the operational changes proposed therein.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a new proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards which had become final on May 28, 2012; selective increased

investment in system hardening; creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the utilities to submit several reports over a series of months, relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further requires the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE has responded to the requirements in the order consistent with the schedule set forth therein. PE's final filing on September 3, 2013, discussed the steps needed to harden the utility's system in order to attempt to achieve various levels of storm response speed described in the February 27 Order, and projected that it would expect to make approximately $2.7 billion in infrastructure investments over 15 years to attempt to achieve the quickest level of response for the largest storm projected in the February 27 Order. The MDPSC has ordered that certain reports of its Staff relating to these matters be provided by May 1, 2014, and otherwise has not issued a schedule for further proceedings in this matter.

NEW JERSEY

JCP&L currently provides BGS for retail customers who do not choose a third party EGS and for customers of third party EGSs that fail to provide the contracted service. The supply for BGS, which is comprised of two components, is provided through contracts procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component and auction, reflecting hourly real time energy prices, is available for larger commercial and industrial customers. The other BGS component and auction, providing a fixed price service, is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On September 7, 2011, the Division of Rate Counsel filed a Petition with the NJBPU asserting that it has reason to believe that JCP&L is earning an unreasonable return on its New Jersey jurisdictional rate base. The Division of Rate Counsel requested that the NJBPU order JCP&L to file a base rate case petition so that the NJBPU may determine whether JCP&L's current rates for electric service are just and reasonable. In its written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012. In the filing, JCP&L requested approval to increase its revenues by approximately $31.5 million and reserved the right to update the filing to include costs associated with the impact of Hurricane Sandy. The NJBPU transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ has been assigned. On February 22, 2013, JCP&L updated its filing to request recovery of $603 million of distribution-related Hurricane Sandy restoration costs, resulting in increasing the total revenues requested to approximately $112 million. On June 14, 2013, JCP&L further updated its filing to: 1) include the impact of a depreciation study which had been directed by the NJBPU; 2) remove costs associated with 2012 major storms, consistent with the NJBPU orders establishing a generic proceeding to review 2011 and 2012 major storm costs (discussed below); and 3) reflect other revisions to JCP&L's filing. That filing represented an increase of approximately $20.6 million over the revenues produced by existing base rates. Testimony has also been filed in the matter by the Division of Rate Counsel and several other intervening parties in opposition to the base rate increase JCP&L requested. Specifically, the testimony of the Division of Rate Counsel's witnesses recommended that revenues produced by JCP&L's base rates for electric service be reduced by approximately $202.8 million (such amount did not address the revenue requirements associated with major storm events of 2011 and 2012, which are subject to review in the generic proceeding). JCP&L filed rebuttal testimony in response to the testimony of other parties on August 7, 2013. Hearings in the rate case have concluded. In the initial briefs of the parties filed on January 27, 2014, the Division of Rate Counsel recommended that base rate revenues be reduced by $214.9 million while the NJBPU Staff recommended a $207.4 million reduction (such amounts do not address the revenue requirements associated with the major storm events of 2011 and 2012). Reply briefs were filed on February 24, 2014.

On March 20, 2013, the NJBPU ordered that a generic proceeding be established to investigate the prudence of costs incurred by all New Jersey utilities for service restoration efforts associated with the major storm events of 2011 and 2012. The Order provided that if any utility had already filed a proceeding for recovery of such storm costs, to the extent the amount of approved recovery had not yet been determined, the prudence of such costs would be reviewed in the generic proceeding. On May 31, 2013, the NJBPU clarified its earlier order to indicate that the 2011 major storm costs would be reviewed expeditiously in the generic proceeding with the goal of maintaining the base rate case schedule established by the ALJ where recovery of such costs would be addressed. The NJBPU further indicated in the May 31 clarification that it would review the 2012 major storm costs in the generic proceeding and the recovery of such costs would be considered through a Phase II in the existing base rate case or through another appropriate method to be determined at the conclusion of the generic proceeding. On June 21, 2013, consistent with NJBPU's orders, JCP&L filed the detailed report in support of recovery of major storm costs with the NJBPU. On November 15, 2013, the Division of Rate Counsel filed testimony recommending that approximately $15 million of JCP&L’s costs be disallowed for recovery. Evidentiary hearings in this proceeding were scheduled for January 2014 but were subsequently adjourned by the NJBPU before their commencement. On February 24, 2014, a Stipulation was filed with the NJBPU by JCP&L, the Division of Rate Counsel and NJBPU Staff which will allow recovery of $736 million of JCP&L’s $744 million of costs related to the significant weather events of 2011 and 2012. As a result, FirstEnergy recorded a regulatory asset impairment charge of approximately $8 million (pre-tax) as of December 31, 2013, included in Amortization of regulatory assets, net within the Consolidated Statements of Income. The agreement, upon which no other party took a position to oppose or support, is now pending before the NJBPU. Recovery of 2011 storm costs will be addressed in the pending base rate case; recovery of 2012 storm costs will be determined by the NJBPU.

Pursuant to a formal Notice issued by the NJBPU on September 14, 2011, public hearings were held in September 2011 to solicit comments regarding the state of preparedness and responsiveness of New Jersey's EDCs prior to, during, and after Hurricane Irene, with additional hearings held in October 2011. Additionally, the NJBPU accepted written comments through October 28, 2011 related to this inquiry. On December 14, 2011, the NJBPU Staff filed a report of its preliminary findings and recommendations with respect to the electric utility companies' planning and response to Hurricane Irene and the October 2011 snowstorm. The NJBPU selected a consultant to further review and evaluate the New Jersey EDCs' preparation and restoration efforts with respect to Hurricane Irene and the October 2011 snowstorm, and the consultant's report was submitted to and subsequently accepted by the NJBPU on September 12, 2012. JCP&L submitted written comments on the report. On January 24, 2013, based upon recommendations in its consultant's report, the NJBPU ordered the New Jersey EDCs to take a number of specific actions to improve their preparedness and responses to major storms. The order includes specific deadlines for implementation of measures with respect to preparedness efforts, communications, restoration and response, post event and underlying infrastructure issues. On May 31, 2013, the NJBPU ordered that the New Jersey EDCs implement a series of new communications enhancements intended to develop more effective communications among EDCs, municipal officials, customers and the NJBPU during extreme weather events and other expected periods of extended service interruptions. The new requirements include making information regarding estimated times of restoration available on the EDC's web sites and through other technological expedients. JCP&L is implementing the required measures consistent with the schedule set out in the above NJBPU's orders.

OHIO

The Ohio Companies primarily operate under an ESP, which expires on May 31, 2014. The material terms of the ESP include:

- Generation supplied through a CBP;
- A load cap of no less than 80%, so that no single supplier is awarded more than 80% of the tranches, which also applies to tranches assigned post-auction;
- A 6% generation discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- No increase in base distribution rates through May 31, 2014; and
- A new distribution rider, Rider DCR, to recover a return of, and on, capital investments in the delivery system.

The Ohio Companies also agreed not to recover from retail customers certain costs related to transmission cost allocations by PJM as a result of ATSI's integration into PJM for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain PJM proceedings. The Ohio Companies also agreed to establish a $12 million fund to assist low income customers over the term of the ESP and agreed to additional matters related to energy efficiency and alternative energy requirements.

On April 13, 2012, the Ohio Companies filed an application with the PUCO to essentially extend the terms of their ESP for two years. The ESP 3 Application was approved by the PUCO on July 18, 2012. Several parties timely filed applications for rehearing. The PUCO issued an Entry on Rehearing on January 30, 2013 denying all applications for rehearing. Notices of appeal to the Supreme Court of Ohio were filed by two parties in the case, Northeast Ohio Public Energy Council and the ELPC. While briefing has been completed, the matter has not yet been scheduled for oral argument.

As approved, the ESP 3 plan continues certain provisions from the current ESP including:

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the existing ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process; and
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers.

As approved, the ESP 3 plan provides additional provisions, including:

- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221 through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

Under SB221, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 1,211 GWHs in 2012 (an increase of 416,000 MWHs over 2011 levels), 1,726 GWHs in 2013, 2,306 GWHs in 2014 and 2,903 GWHs for each year thereafter through 2025. The Ohio Companies were also required to reduce peak demand in 2009 by 1%, with an additional 0.75% reduction each year thereafter through 2018. On May 15, 2013, the Ohio Companies filed their 2012 Status Update Report in which they indicated compliance with 2012 statutory energy efficiency and peak demand reduction benchmarks.

In accordance with PUCO Rules and a PUCO directive, on July 31, 2012 the Ohio Companies filed their three-year portfolio plan for the period January 1, 2013 through December 31, 2015. Estimated costs for the three Ohio Companies' plans total approximately $250 million over the three-year period, which is expected to be recovered in rates to the extent approved by the PUCO. Hearings were held with the PUCO in October 2012. On March 20, 2013, the PUCO approved the three-year portfolio plan for 2013-2015. Applications for rehearing were filed by the Ohio Companies and several other parties on April 19, 2013. The Ohio Companies filed their request for rehearing primarily to challenge the PUCO's decision to mandate that they offer planned energy efficiency resources into PJM's base residual auction. On May 15, 2013, the PUCO granted the applications for rehearing for the sole purpose of further consideration of the matter. On July 17, 2013, the PUCO denied the Ohio Companies' application for rehearing, in part, but authorized the Ohio Companies to receive 20% of any revenues obtained from bidding energy efficiency and demand response reserves into the PJM auction. The PUCO also confirmed that the Ohio Companies can recover PJM costs and applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. On August 16, 2013, ELPC and OCC filed applications for rehearing under the basis that the PUCO's authorization for the Ohio Companies to share in the PJM revenues was unlawful. The PUCO granted rehearing on September 11, 2013 for the sole purpose of further consideration of the issue.

On September 16, 2013, the Ohio Companies filed with the Supreme Court of Ohio a notice of appeal of the PUCO's July 17, 2013 Entry on Rehearing related to energy efficiency, alternative energy, and long-term forecast rules stating that the rules issued by the PUCO are inconsistent with and are not supported by statutory authority. On October 23, 2013, the PUCO filed a motion to dismiss the appeal. The Ohio Companies' response was filed on November 4, 2013. The motion is still pending and additional briefing has followed. The Ohio Companies filed their merit brief with the Supreme Court of Ohio on February 24, 2014.

SB221 requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2024. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet the renewable energy requirements established under SB221. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs and selected auditors to perform a financial and management audit. Final audit reports filed with the PUCO generally supported the Ohio Companies' approach to procurement of RECs, but also recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of in-state renewable obligations that the auditor characterized as excessive. Following the hearing, the PUCO issued an Opinion and Order on August 7, 2013 approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for part of the purchases arising from one auction and directing the Ohio Companies to credit non-shopping customers in the amount of $43.3 million, plus interest, and to file tariff schedules reflecting the refund and interest costs within 60 days following the issuance of a final appealable order on the basis that the Ohio Companies did not prove such purchases were prudent. The Ohio Companies, along with other parties, timely filed applications for rehearing on September 6, 2013. On December 18, 2013, the PUCO denied all of the applications for rehearing. Based on the PUCO ruling, a regulatory charge of approximately $51 million, including interest, was recorded in the fourth quarter of 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. On December 24, 2013, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio. On February 10, 2014, the Supreme Court of Ohio granted the Ohio Companies' motion for stay, which went into effect on February 14, 2014. On February 18, 2014, the Office of Consumers' Counsel and the Environmental Law and Policy Center also filed appeals of the PUCO's order.

In March 2012, the Ohio Companies conducted an RFP process to obtain SRECs to help meet the statutory benchmarks for 2012 and beyond. With the successful completion of this RFP, the Ohio Companies achieved their in-state solar compliance requirements for 2012. The Ohio Companies also held a short-term RFP process to obtain all state SRECs and both in-state and all state non-solar RECs to help meet the statutory benchmarks for 2012. The Ohio Companies recently reported that they met all of their annual renewable energy resource requirements for reporting year 2012. The Ohio Companies conducted an RFP in 2013 to cover their all-state SREC and their in-state and all-state REC compliance obligations.

The PUCO instituted a statewide investigation on December 12, 2012 to evaluate the vitality of the competitive retail electric service market in Ohio. The PUCO provided interested stakeholders the opportunity to comment on twenty-two questions. The questions posed are categorized as market design and corporate separation. The Ohio Companies timely filed their comments on March 1, 2013, and filed reply comments on April 5, 2013. On June 5, 2013, the PUCO requested additional comments and reply comments on the topics of market design and corporate separation, which the Ohio Companies timely filed on July 8, 2013 and July 22, 2013, respectively. The PUCO held a series of workshops throughout 2013, which included an en banc workshop on December 11, 2013. The PUCO Staff filed a report on January 16, 2014, which contained a limited discussion of the workshops and the PUCO Staff's recommendations. The Ohio Companies submitted comments on February 6, 2014 and Reply Comments on February 20, 2014.

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2015, and provide for the competitive procurement of generation supply for customers that do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. The default service supply is currently provided by wholesale suppliers through a mix of long-term and short-term contracts procured through descending clock auctions, competitive requests for proposals and spot market purchases. On November 4, 2013, the Pennsylvania Companies filed a DSP that will provide the method by which they will procure the supply for their default service obligations for the period of June 1, 2015 through May 31, 2017. The Pennsylvania Companies proposed programs call for quarterly descending clock auctions to procure 3, 12, 24, and 48-month energy contracts, as well as, one RFP seeking 2-year contracts to secure SRECs for ME, PN, and Penn. Hearings on the plans are scheduled to be held March 4-7, 2014. The Pennsylvania Companies expect a decision from the PPUC by August 4, 2014.

The PPUC entered an Order on March 3, 2010 that denied the recovery of marginal transmission losses through the TSC rider for the period of June 1, 2007 through March 31, 2008, and directed ME and PN to submit a new tariff or tariff supplement reflecting the removal of marginal transmission losses from the TSC. Pursuant to a plan approved by the PPUC, ME and PN refunded those amounts to customers over a 29-month period that began in January of 2011. On appeal, the Commonwealth Court affirmed the PPUC's Order to the extent that it holds that line loss costs are not transmission costs and, therefore, the approximately $254 million in marginal transmission losses and associated carrying charges for the period prior to January 1, 2011, are not recoverable under ME's and PN's TSC riders. The Pennsylvania Supreme Court denied ME's and PN's Petition for Allowance of Appeal and the Supreme Court of the United States denied ME's and PN's Petition for Writ of Certiorari. ME and PN also filed a complaint in the U.S. District Court for the Eastern District of Pennsylvania to obtain an order that would enjoin enforcement of the PPUC and Pennsylvania court orders under a theory of federal preemption on the question of retail rate recovery of the marginal transmission loss charges. On September 30, 2013, the U.S. District Court granted the PPUC’s motion to dismiss. As a result of the U.S. District Court's September 30, 2013 decision, FirstEnergy recorded a regulatory asset impairment charge of approximately $254 million (pre-tax) in the quarter ended September 30, 2013 included in Amortization of regulatory assets, net within the Consolidated Statement of Income. The balance of marginal transmission losses was fully refunded to customers by the second quarter of 2013. On October 29, 2013, ME and PN filed a Notice of Appeal of the U.S. District Court’s decision to dismiss the complaint with the United States Court of Appeals for the Third Circuit. On December 30, 2013, ME and PN filed a brief with the Third Circuit that explained why it was legal error for the U.S. District Court to dismiss the complaint. The PPUC filed its brief on February 3, 2014, and ME and PN filed a reply brief on February 21, 2014. Oral argument has been scheduled for April 9, 2014.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan (EE&C Plan) by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 provides for potentially significant financial penalties to be assessed on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted a report on November 15, 2011, in which they reported on their compliance with statutory May 31, 2011, energy efficiency benchmarks. ME, PN and Penn achieved the 2011 benchmarks; however WP did not. WP could be subject to a statutory penalty of between $1 and $20 million. On July 15, 2013, the Pennsylvania Companies filed their preliminary energy efficiency and demand reduction results for the period ending May 31, 2013, indicating that all Pennsylvania Companies are expected to meet their statutory obligations. On November 15, 2013, the Pennsylvania Companies submitted their energy efficiency and peak demand reduction report for the period ending May 31, 2013, in which they indicated that all of the Pennsylvania Companies met their statutory requirements.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and in an Order entered on August 3, 2012, the PPUC directed all of the electric utilities in Pennsylvania to submit by November 15, 2012, a Phase II EE&C Plan that would be in effect for the period June 1, 2013 through May 31, 2016. The PPUC has deferred ruling on the need to create peak demand reduction targets until it receives more information from the EE&C statewide evaluator. Based upon information received, the PPUC has not included a peak demand reduction requirement in the Phase II plans. The Pennsylvania Companies filed their Phase II plans and supporting testimony in November 2012. On January 16, 2013, the Pennsylvania Companies reached a settlement with all but one party on all but one issue. The settlement provides for the Pennsylvania Companies to meet with interested parties to discuss ways to expand upon the EE&C programs and incorporate any such enhancements after the plans are approved, provided that these enhancements will not jeopardize the Pennsylvania Companies' compliance with their required targets or exceed the statutory spending caps. On February 6, 2013, the Pennsylvania Companies filed revised Phase II EE&C Plans to conform the plans to the terms of the settlement. Total costs of these plans are expected to be approximately $234 million. All such costs are expected to be recoverable through the Pennsylvania Companies reconcilable Phase II EE&C Plan C riders. The remaining issue, raised by a natural gas company, involved the recommendation that the Pennsylvania Companies include in their plans incentives for natural gas space and water heating appliances. On March 14, 2013, the PPUC approved the 2013-2016 EE&C plans of the Pennsylvania Companies, adopting the settlement, and rejecting the natural gas companies recommendations.

In addition, Act 129 required utilities to file a SMIP with the PPUC. On December 31, 2012, the Pennsylvania Companies filed their Smart Meter Deployment Plan. The Deployment Plan requests deployment of approximately 98.5% of the smart meters to be installed over the period 2013 to 2019, and the remaining meters in difficult to reach locations to be installed by 2022, with an estimated life cycle cost of about $1.25 billion. Such costs are expected to be recovered through the Pennsylvania Companies'

PPUC-approved Riders SMT-C. Evidentiary hearings were held and briefs were submitted by the Pennsylvania Companies and the Office of Consumer Advocate. On November 8, 2013, the ALJ issued a Recommended Decision recommending that the Pennsylvania Companies' Deployment Plan be adopted with certain modifications, including, among other things, that the Pennsylvania Companies perform further benchmarking analyses on their costs and hire an independent consultant to perform further analyses on potential savings. On December 2, 2013, the Pennsylvania Companies submitted exceptions in which they challenged, among other things, certain recommendations in the ALJ's decision, and requested approval of a modification to the deployment schedule so as to allow the entire Penn smart meter system (170,000 meters) to be built by the end of 2015, instead of the original proposed installation of 60,000 meters by the end of 2016. The Office of Consumer Advocate took exception to one issue and both parties filed replies to exceptions on December 12, 2013. The case is now before the PPUC for consideration. A decision is expected during the first quarter of 2014.

In the PPUC Order approving the FirstEnergy and Allegheny merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions concerning retail markets in Pennsylvania to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A final order was issued on February 15, 2013, providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items. Subsequently, the PPUC established five workgroups and one comment proceeding in order to seek resolution of certain matters and to clarify certain obligations that arose from that order.

The PPUC issued a Proposed Rulemaking Order on August 25, 2011, which proposed a number of substantial modifications to the current Code of Conduct regulations that were promulgated to provide competitive safeguards to the competitive retail electricity market in Pennsylvania. The proposed changes include, but are not limited to: an EGS may not have the same or substantially similar name as the EDC or its corporate parent; EDCs and EGSs would not be permitted to share office space and would need to occupy different buildings; EDCs and affiliated EGSs could not share employees or services, except certain corporate support, emergency, or tariff services (the definition of "corporate support services" excludes items such as information systems, electronic data interchange, strategic management and planning, regulatory services, legal services, or commodities that have been included in regulated rates at less than market value); and an EGS must enter into a trademark agreement with the EDC before using its trademark or service mark. The Proposed Rulemaking Order was published on February 11, 2012, and comments were filed by the Pennsylvania Companies and FES on March 27, 2012. If implemented these rules could require a significant change in the ways FES and the Pennsylvania Companies do business in Pennsylvania, and could possibly have an adverse impact on their results of operations and financial condition. Pennsylvania's Independent Regulatory Review Commission subsequently issued comments on the proposed rulemaking on April 26, 2012, which called for the PPUC to further justify the need for the proposed revisions by citing a lack of evidence demonstrating a need for them. The House Consumer Affairs Committee of the Pennsylvania General Assembly also sent a letter to the Independent Regulatory Review Commission on July 12, 2012, noting its opposition to the proposed regulations as modified.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement reached with the other parties and approved by the WVPSC in June 2010 that provided for:

- $40 million annualized base rate increases effective June 29, 2010;
- Deferral of February 2010 storm restoration expenses over a maximum five-year period;
- Additional $20 million annualized base rate increase effective in January 2011;
- Decrease of $20 million in ENEC rates effective January 2011, providing for deferral of related costs for later recovery in 2012; and
- Moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

The WVPSC opened a general investigation into the June 29, 2012, derecho windstorm with data requests for all utilities. A public meeting for presentations on utility responses and restoration efforts was held on October 22, 2012 and two public input hearings have been held. The WVPSC issued an Order in this matter on January 23, 2013 closing the proceeding and directing electric utilities to file a vegetation management plan within six months and to propose a cost recovery mechanism. This Order also requires MP and PE to file a status report regarding improvements to their storm response procedures by the same date. On July 23, 2013, MP and PE filed their vegetation management plans, which provided for recovery of costs through a surcharge mechanism. A hearing was held on December 3, 2013, and briefing followed but the WVPSC has not yet issued an opinion in this matter.

MP and PE filed their Resource Plan with the WVPSC in August 2012 detailing both supply and demand forecasts and noting a substantial capacity deficiency. MP and PE filed a Petition for approval of a Generation Resource Transaction with the WVPSC in November 2012 that proposed a net ownership transfer of 1,476 MW of coal-fired generation capacity to MP. The proposed transfer involved MP's acquisition of the remaining ownership of the Harrison Power Station from AE Supply and the sale of MP's minority interest in the Pleasants Power Station to AE Supply. FERC authorized the transfers on April 23, 2013 and the financing on May 13, 2013. A Joint Settlement Agreement was filed by the majority of parties on August 21, 2013. On October 7, 2013, the WVPSC

authorized the transaction, with certain conditions, and on October 9, 2013, the transaction closed resulting in MP recording a pre-tax impairment charge of approximately $322 million in the fourth quarter of 2013 to reduce the net book value of the Harrison Power Station to the amount that was permitted to be included in jurisdictional rate base. The charge is included in Impairment of long lived assets within the Consolidated Statement of Income. Concurrently, MP recognized a regulatory liability of approximately $23 million representing refunds to customers associated with the excess purchase price received by MP above the net book value of MP's minority interest in the Pleasants Power Station. The transaction resulted in AE Supply receiving net consideration of $1.1 billion and MP's assumption of a $73.5 million pollution control note. The $1.1 billion net consideration was originally financed by MP through an equity infusion from FE of approximately $527 million and a note payable to AE Supply of approximately $573 million. The note payable to AE Supply was paid in the fourth quarter of 2013. In accordance with the settlement, MP and PE will file a base rate case by April 30, 2014. On November 6, 2013, the WVCAG petitioned for appeal with the West Virginia Supreme Court. MP and PE filed their response to the WVCAG petition on December 27, 2013 and WVCAG filed its reply on January 16, 2014. Oral argument before the Supreme Court is scheduled for March 5, 2014.

RELIABILITY MATTERS

Federally-enforceable mandatory reliability standards apply to the bulk electric system and impose certain operating, record-keeping and reporting requirements on the Utilities, FES, AE Supply, FG, FENOC, ATSI and TrAIL. NERC is the ERO designated by FERC to establish and enforce these reliability standards, although NERC has delegated day-to-day implementation and enforcement of these reliability standards to eight regional entities, including RFC. All of FirstEnergy's facilities are located within the RFC region. FirstEnergy actively participates in the NERC and RFC stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards implemented and enforced by RFC.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases “self-reporting” an item to RFC. Moreover, it is clear that the NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk power system could result in the imposition of financial penalties that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis - each customer in the zone would pay based on its total usage of energy within PJM. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit found that FERC had not supported a prior FERC decision to allocate costs for new 500 kV and higher voltage facilities on a load ratio share basis and, based on that finding, remanded the rate design issue to FERC. In an order dated January 21, 2010, FERC set this matter for a “paper hearing” and requested parties to submit written comments. FERC identified nine separate issues for comment and directed PJM to file the first round of comments. PJM filed certain studies with FERC on April 13, 2010, which demonstrated that allocation of the cost of high voltage transmission facilities on a beneficiary pays basis results in certain LSEs in PJM bearing the majority of the costs. FirstEnergy and a number of other utilities, industrial customers and state utility commissions supported the use of the beneficiary pays approach for cost allocation for high voltage transmission facilities. Other utilities and state utility commissions supported continued socialization of these costs on a load ratio share basis. On March 30, 2012, FERC issued an order on remand reaffirming its prior decision that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp (or socialized) rate based on the amount of load served in a transmission zone and concluding that such methodology is just and reasonable and not unduly discriminatory or preferential. On April 30, 2012, FirstEnergy requested rehearing of FERC's March 30, 2012 order and on March 22, 2013, FERC denied rehearing. On March 29, 2013, FirstEnergy filed its Petition for Review with the U.S. Court of Appeals for the Seventh Circuit, and the case subsequently was consolidated for briefing and disposition before that court. Briefing is complete, and the case will be scheduled for oral argument, with a decision currently expected in 2014.

Order No. 1000, issued by FERC on July 21, 2011, required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. To demonstrate compliance with the regional cost allocation principles of the order, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC on October 11, 2012, proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the effective date of the compliance filing. On January 31, 2013, FERC conditionally accepted the hybrid method to be effective on February 1, 2013, subject to refund and to a future order on PJM's separate Order No. 1000 compliance filing. On March 22, 2013, FERC granted final acceptance of the hybrid method. Certain parties have sought rehearing of parts of FERC's March 22, 2013 order. These requests for rehearing are pending before FERC. On July 10, 2013, the PJM transmission owners, including

FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between: (1) the PJM region and the NYISO region and; (2) the PJM region and the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the cost of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region. On the same date, also in response to Order No. 1000, the PJM transmission owners, including FirstEnergy, also submitted to FERC a filing stating that the cost allocation provisions for interregional transmission projects provided in the Joint Operating Agreement between PJM and MISO comply with the requirements of Order No. 1000. On December 30, 2013, FERC conditionally accepted the PJM/SERTP cross-border project cost allocation filing, subject to refund and future orders in PJM's and SERTP's related Order No. 1000 interregional compliance proceedings. The PJM/NYISO and PJM/MISO cross-border project cost allocation filings remain pending before FERC. On January 16, 2014, FERC issued an order regarding the effective date of PJM's separate Order No. 1000 compliance filing, noting that it would address the merits of the comments on and protests to that filing and related compliance filings in a future order.

Numerous parties, including ATSI, FES, TrAIL, OE, CEI, TE, Penn, JCP&L, ME, MP, PN, WP and PE, have sought judicial review of Order No. 1000 before the U.S. Court of Appeals for the D.C. Circuit. Briefing was completed in December 2013 and oral argument is scheduled for March 20, 2014.

The outcome of these proceedings and their impact, if any, on FirstEnergy cannot be predicted at this time.

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone. While many of the matters involved with the move have been resolved, FERC denied recovery by means of ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis that demonstrates net benefits to customers from the move. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC to resolve the exit fee and transmission cost allocation issues. However, FERC subsequently rejected that settlement stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. On October 21, 2013, FirstEnergy filed a request for rehearing of FERC's order.

Separately, the question of ATSI's responsibility of certain costs for the “Michigan Thumb” transmission project continues to be disputed. Potential responsibility arises under the MISO MVP tariff, which has been litigated in complex proceedings in front of FERC and certain U.S. appellate courts. The MISO and its allied parties assert that the benefits to the ATSI zone for the Michigan Thumb project are roughly commensurate with the costs that MISO desires to charge to the ATSI zone, estimated to be as much as $16 million per year. ATSI has submitted evidence that the Michigan Thumb project provides no electric benefits to the ATSI zone and, on that basis, opposes the MISO’s efforts to impose these costs to the ATSI zone loads. The MISO and its allied parties also assert that certain language in the MISO Transmission Owners Agreement requires ATSI to pay these charges. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. While FERC proceedings regarding whether the MISO can charge ATSI for MVP costs remain pending, on February 24, 2014, the U.S. Supreme Court declined to hear appeals filed by FirstEnergy and other parties of the Seventh Circuit's June 2013 decision upholding FERC's acceptance of the MISO's generic MVP cost allocation proposal.

In the May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM could be charged to transmission customers in the ATSI zone. ATSI sought rehearing of the question of whether the ATSI zone should pay these legacy RTEP charges and, on September 20, 2012, FERC denied ATSI's request for rehearing. ATSI subsequently filed a petition for review with the U.S. Court of Appeals for the D.C. Circuit. The case thereafter was briefed and oral arguments took place on December 11, 2013. A decision currently is expected in the second quarter of 2014.

The outcome of those proceedings that address the remaining open issues related to ATSI's move into PJM cannot be predicted at this time.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the U.S. Court of Appeals for the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets, during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011, and affirmed the dismissal in June 2012. On June 20, 2012, the California Parties appealed FERC's decision back to the Ninth Circuit. Briefing was completed before the Ninth Circuit on October 23, 2013. The timing of further action by the Ninth Circuit is unknown.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed another complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets

during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General has appealed FERC's dismissal of its complaint to the Ninth Circuit, which has consolidated the case with other pending appeals related to California refund claims, and stayed the proceedings pending further order.

FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

The PATH project was proposed to be comprised of a 765 kV transmission line from West Virginia through Virginia and into Maryland, modifications to an existing substation in Putnam County, West Virginia, and the construction of new substations in Hardy County, West Virginia and Frederick County, Maryland. PJM initially authorized construction of the PATH project in June 2007. On August 24, 2012, the PJM Board of Managers canceled the PATH project, which it had suspended in February 2011. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed return on equity of 10.9% (10.4% base plus 0.5% RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% return on equity adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement judge procedures and hearing if the parties do not agree to a settlement. The issues subject to settlement include the prudence of the costs, the base return on equity and the period of recovery. PATH-Allegheny and PATH-WV are currently engaged in settlement discussions with the other parties. Depending on the outcome of a possible settlement or hearing, if settlement is not achieved, PATH-Allegheny and PATH-WV may be required to refund certain amounts that have been collected under their formula rate.

PATH-Allegheny and PATH-WV have requested rehearing of FERC's denial of the 0.5% return on equity adder for RTO membership; that request for rehearing remains pending before FERC. In addition, FERC has consolidated for settlement judge procedures and hearing purposes three formal challenges to the PATH formula rate annual updates submitted to FERC in June 2010, June 2011 and June 2012, with the September 28, 2012 filing for recovery of costs associated with the cancellation of the PATH project.

Hydroelectric Asset Sale

On September 4, 2013, certain of FirstEnergy’s subsidiaries submitted filings with FERC for authorization to sell eleven hydroelectric power plant projects to subsidiaries of Harbor Hydro Holdings, LLC (Harbor Hydro), a subsidiary of LS Power Equity Partners II, LP (LS Power). The eleven hydroelectric projects are: the Seneca Pumped Storage Project, Allegheny Lock & Dam No. 5, Allegheny Lock & Dam No. 6, the Lake Lynn Project, the Millville Hydro Project, the Dam No. 4 Project, the Dam No. 5 Project, and four additional projects located in Shenandoah, Front Royal and Luray, Virginia. The eleven projects have a combined generating capacity of approximately 527 MW. On February 12, 2014, the sale of the hydroelectric power plants to LS Power closed for approximately $395 million. See Note 20, Discontinued Operations and Assets Held for Sale for additional information regarding the assets sold.

MISO Capacity Portability

On June 11, 2012, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FERC is responding to suggestions from MISO and the MISO stakeholders that PJM's rules regarding the criteria and qualifications for external generation capacity resources be changed to ease participation by resources that are located in MISO in PJM's RPM capacity auctions. FirstEnergy submitted comments and reply comments in August 2012. In the fall of 2012, FirstEnergy participated in certain stakeholder meetings to review various proposals advanced by MISO. Although none of MISO's proposals attracted significant stakeholder support, in January 2013, MISO filed a pleading with FERC that renewed many of the arguments advanced in prior MISO filings and asked FERC to take expedited action to address MISO's allegations. FirstEnergy and other parties subsequently submitted filings arguing that MISO's concerns largely are without foundation and suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. On April 2, 2013, FERC issued an order directing MISO and PJM to make presentations to FERC regarding ongoing regional efforts to address whether barriers to transfer capability exist between the MISO and PJM regions and the actions the FERC should take to address any such barriers. The RTOs presented their respective positions to FERC on June 20, 2013 and provided additional information regarding their stakeholder prioritization survey, in response to a FERC request on June 27, 2013. On September 26, 2013, the RTOs jointly submitted an informational filing providing a description of and schedule for their Joint and Common Market initiatives. On December 19, 2013, FERC issued an order directing that FERC staff are to attend the “joint and common market” stakeholder meetings for the purpose of monitoring progress on the initiatives described in the September 26, 2013 joint informational filing and establishing a new proceeding to reflect the broadened scope of issues contemplated by that filing and the RTOs' joint and common market initiatives. FERC has not acted on the presentations, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

MOPR Reform

On December 7, 2012, PJM filed amendments to its tariff to revise the MOPR used in the RPM. PJM revised the MOPR to add two broad, categorical exemptions, eliminate an existing exemption, and to limit the applicability of the MOPR to certain capacity resources. The filing also included related and conforming changes to the RPM posting requirements and to those provisions describing the role of the Independent Market Monitor for the PJM Region. On May 2, 2013, FERC issued an order in large part accepting PJM's proposed reform of the MOPR, including the proposed exemptions and applicability but also requiring PJM to commit to future review and, if necessary, additional revisions to the MOPR to accommodate changing market conditions. On June 3, 2013, FirstEnergy submitted a request for rehearing of FERC's May 2, 2013 order. In its rehearing request, FirstEnergy referenced the results of the May 2013 PJM RPM capacity auction, and publicly-available data about the reasons for the unexpectedly low "rest-of-RTO" clearing price of $59 per MW-day, as supporting its contention that the MOPR reform depressed prices as predicted in FirstEnergy's December 28, 2012 and January 25, 2013 comments. FirstEnergy's request for rehearing is pending before FERC.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and they operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM tariff, the funds that are set aside to pay FTRs can be diverted to other uses, resulting in “underfunding” of FTR payments. Since June of 2010, FES and AE Supply have lost more than $65.5 million in revenues that they otherwise would have received as FTR holders to hedge congestion costs. FES and AE Supply expect to continue to experience significant underfunding.

On December 28, 2011, FES and AE Supply filed a complaint with FERC for the purpose of modifying certain provisions in the PJM tariff to eliminate FTR underfunding. On March 2, 2012, FERC issued an order dismissing the complaint. In its order, FERC ruled that it was not appropriate to initiate action at that time because of the unknown root causes of FTR underfunding. FERC directed PJM to convene stakeholder proceedings for the purpose of determining the root causes of the FTR underfunding. FERC went on to note that its dismissal of the complaint was without prejudice to FES and AE Supply or any other affected entity filing a complaint if the stakeholder proceedings proved unavailing. FES and AE Supply sought rehearing of FERC's order and, on July 19, 2012, FERC denied rehearing. In April, 2012, PJM issued a report on FTR underfunding. However, the PJM stakeholder process proved unavailing as the stakeholders were not willing to change the tariff to eliminate FTR underfunding. Accordingly, on February 15, 2013, FES and AE Supply refiled their complaint with FERC for the purpose of changing the PJM tariff to eliminate FTR underfunding. Various parties filed responsive pleadings, including PJM. On June 5, 2013, FERC issued its order denying the new complaint. On July 5, 2013, FirstEnergy filed a request for rehearing of FERC's order. FES and AE Supply's request for rehearing, and all subsequent filings in the docket, are pending before FERC.

PJM RPM Tariff Amendments

In November 2013, PJM began to submit a series of amendments to its RPM capacity tariff in order to address certain problems that have been observed in recent auctions. These problems can be grouped into three categories: (i) Demand Response (DR); (ii) imports; and (iii) modeling of transmission upgrades in calculating geographic clearing prices. The purpose of PJM’s tariff amendments is to ensure that resources that clear in the RPM auctions are available and able to satisfy all obligations under the PJM tariffs. In each of the affected dockets, FirstEnergy submitted comments as part of a coalition of utilities (generally including an affiliate of AEP, Duke and Dayton). The FirstEnergy/coalition position was that all of the PJM proposals should be accepted as proposed, and that the FERC should order PJM to take additional steps that should have the effect of eliminating additional distortions and flaws in the RPM market. FERC issued deficiency letters requesting additional information from PJM regarding the imports and modeling filings, and on January 30, 2014 accepted the DR filing as proposed. On February 18 and 21, 2014, respectively, PJM filed its responses to FERC's deficiency letters regarding the modeling and imports filings. PJM's compliance filings and all other filings in the dockets are pending before FERC.

Market-Based Rate Authority, Triennial Update

OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP, PE, AE Supply, FES, FG, NG, FirstEnergy Generation Mansfield Unit 1 Corp., Buchanan Generation, LLC, and Green Valley Hydro, LLC each hold authority from FERC to sell electricity at market-based rates. One condition for retaining this authority is that every three years each entity must file an update with the FERC that demonstrates that each entity continues to meet FERC’s requirements for holding market-based rate authority. On December 20, 2013, FESC submitted to FERC the most recent triennial market power analysis filing for each market-based rate holder for the current cycle of this filing requirement. That filing is pending before FERC.

16. COMMITMENTS, GUARANTEES AND CONTINGENCIES

NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $13.6 billion (assuming 104 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 million; and (ii) $13.2 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to $127 million (but not more than $19 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy's maximum potential assessment under these provisions would be $509 million (OE-$44 million, NG-$442 million, and TE-$23 million) per incident but not more than $76 million (OE-$7 million, NG-$66 million, and TE-$3 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of NEIL, which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy's subsidiaries have policies, renewable yearly, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately $2 billion (OE-$168 million, NG-$1.7 billion, TE-$90 million) for replacement power costs incurred during an outage after an initial 20-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy's present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately $14 million (OE-$1.2 million, NG-$12 million and TE-$0.6 million).

FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to $2.75 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately $79 million (OE-$7 million, NG-$68 million, TE-$3 million and ME-$1 million).

FirstEnergy intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that replacement power, property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at any of FirstEnergy's plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by FirstEnergy's insurance policies, or to the extent such insurance becomes unavailable in the future, FirstEnergy would remain at risk for such costs.

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of $1.06 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.

GUARANTEES AND OTHER ASSURANCES

FirstEnergy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. FirstEnergy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party.

As of December 31, 2013, outstanding guarantees and other assurances aggregated approximately $4.3 billion, consisting of parental guarantees ($1,375 million), subsidiaries' guarantees ($2,197 million) and other guarantees ($742 million).

Of this amount, substantially all relates to guarantees of wholly-owned consolidated entities. FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG, and NG would have claims against each of FES, FG, and NG, regardless of whether their primary obligor is FES, FG, or NG.

COLLATERAL AND CONTINGENT-RELATED FEATURES

In the normal course of business, FE and its subsidiaries routinely enter into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuel, and emission allowances. Certain bilateral agreements and derivative instruments contain provisions that require FE or its subsidiaries to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon FE's or its subsidiaries' credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. The incremental collateral requirement allows for the offsetting of assets and liabilities with the same counterparty, where the contractual right of offset exists under applicable master netting agreements.

Bilateral agreements and derivative instruments entered into by FE and its subsidiaries have margining provisions that require posting of collateral. Based on FES' power portfolio exposure as of December 31, 2013, FES has posted collateral of $142 million and AE supply has posted collateral of $8 million. The Regulated Distribution segment has posted collateral of $11 million.

These credit-risk-related contingent features stipulate that if the subsidiary were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. Depending on the volume of forward contracts and future price movements, higher amounts for margining could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a "material adverse event," the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of December 31, 2013:

Collateral Provisions	FES	AE Supply	Utilities	Total
		(In millions)		
Split Rating (One rating agency's rating below investment grade)	$ 496	$ 6	$ 53	$ 555
BB+/Ba1 Credit Ratings	$ 542	$ 6	$ 53	$ 601
Full impact of credit contingent contractual obligations	$ 777	$ 58	$ 88	$ 923

Excluded from the preceding chart are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and Competitive Energy Services segment. As of December 31, 2013, neither FES nor AE Supply had any collateral posted with their affiliates. In the event of a senior unsecured credit rating downgrade to below S&P's BB- or Moody's Ba3, FES and AE Supply would be required to post $66 million and $2 million, respectively.

OTHER COMMITMENTS AND CONTINGENCIES

FirstEnergy is a guarantor under a syndicated three-year senior secured term loan facility due October 18, 2015, under which Global Holding borrowed $350 million. Proceeds from the loan were used to repay Signal Peak's and Global Rail's maturing $350 million syndicated two-year senior secured term loan facility. In addition to FirstEnergy, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, have also provided their joint and several guaranties of the obligations of Global Holding under the new facility.

In connection with the current facility, 69.99% of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with FEV's and WMB Marketing Ventures, LLC's respective 33-1/3% membership interests in Global Holding, are pledged to the lenders under the current facility as collateral.

FirstEnergy, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed to use their best efforts to refinance the new facility no later than July 20, 2015, which reflects the terms of an amendment dated August 14, 2013, on a non-recourse basis so that FirstEnergy's guaranty can be terminated and/or released. If that refinancing does not occur, FirstEnergy may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the new facility in full. In lieu of providing such funding, the co-owners, at FirstEnergy's option, may provide their several guaranties of Global Holding's obligations under the facility. FirstEnergy receives a fee for providing its guaranty, payable semiannually, which accrued at a rate of 4% through December 31, 2012, and accrues at a rate of 5% from January 1, 2013 through October 18, 2015, which amends the rate in the prior agreement, in each case based upon the average daily outstanding aggregate commitments under the facility for such semiannual period.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Compliance with environmental regulations could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that FirstEnergy competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

CAA Compliance

FirstEnergy is required to meet federally-approved SO_2 and NOx emissions regulations under the CAA. FirstEnergy complies with SO_2 and NOx reduction requirements under the CAA and SIP(s) by burning lower-sulfur fuel, utilizing combustion controls and post-combustion controls, generating more electricity from lower or non-emitting plants and/or using emission allowances.

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a "safe, responsible, prudent and proper manner." One complaint

was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued an NOV to GenOn Energy, Inc. alleging NSR violations at the Keystone, Portland and Shawville coal-fired plants based on “modifications” dating back to the mid-1980s. JCP&L, as the former owner of 16.67% of the Keystone Station, ME, as a former owner and operator of the Portland Station, and PN as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2011, the U.S. DOJ filed a complaint against PN in the U.S. District Court for the Western District of Pennsylvania seeking injunctive relief against PN based on alleged “modifications” at the coal-fired Homer City generating plant during 1991 to 1994 without pre-construction NSR permitting in violation of the CAA's PSD and Title V permitting programs. The complaint was also filed against the former co-owner, NYSEG, and various current owners of Homer City, including EME Homer City Generation L.P. and affiliated companies, including Edison International. In addition, the Commonwealth of Pennsylvania and the states of New Jersey and New York intervened and filed separate complaints regarding Homer City seeking injunctive relief and civil penalties. In October 2011, the Court dismissed all of the claims with prejudice of the U.S. DOJ and the Commonwealth of Pennsylvania and the states of New Jersey and New York against all of the defendants, including PN. In December 2011, the U.S., the Commonwealth of Pennsylvania and the states of New Jersey and New York all filed notices appealing to the Third Circuit Court of Appeals which affirmed the dismissal on August 21, 2013 and then denied petitions for rehearing on December 12, 2013. PN believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints. The parties dispute the scope of NYSEG's and PN's indemnity obligation to and from Edison International. PN is unable to predict the outcome of this matter or estimate the loss or possible range of loss.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations, at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. The EPA's NOV alleges equipment replacements during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically, opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. FG intends to comply with the CAA and Ohio regulations, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued additional CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. AE intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In June 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Allegheny Utilities in the U.S. District Court for the Western District of Pennsylvania alleging, among other things, that Allegheny performed major modifications in violation of the NSR provisions of the CAA and the Pennsylvania Air Pollution Control Act at the coal-fired Hatfield's Ferry, Armstrong and Mitchell Plants in Pennsylvania. A non-jury trial on liability only was held in September 2010. On February 6, 2014, the Court entered judgment for AE, AE Supply, and the Allegheny Utilities finding they had not violated the CAA or the Pennsylvania Air Pollution Control Act. This decision does not change the status of these plants which remain deactivated.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the D.C. Circuit decided that CAIR violated the CAA but allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaces CAIR with a new rule consistent with the Court's decision. In July 2011, the EPA finalized CSAPR, to replace CAIR, requiring reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit and was ultimately vacated by the Court on August 21, 2012. The Court has ordered the EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. On January 24, 2013, EPA and intervenors' petitions seeking rehearing or rehearing en banc were denied by the U.S. Court of Appeals for the D.C. Circuit. On June 24, 2013, the Supreme Court of the United States agreed to review the decision vacating CSAPR and heard oral argument on December 10, 2013. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional extension through April 16, 2016 for MATS compliance at the Fort Martin, Harrison and Pleasants stations. On March 20, 2013, the PA DEP granted an extension through April 16, 2016 for MATS compliance at the Hatfield's Ferry and Bruce Mansfield stations. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. MATS has been challenged in the U.S. Court of Appeals for the D.C. Circuit by various entities, including FirstEnergy's challenge of the PM emission limit imposed on petroleum coke boilers, such as Bay Shore Unit 1. Oral arguments were heard on December 10, 2013. Depending on the outcome of these proceedings and how the MATS are ultimately implemented, FirstEnergy's total cost of compliance with MATS is currently estimated to be approximately $465 million (Competitive Energy Services segment of $240 million and Regulated Distribution segment of $225 million).

As of September 1, 2012, Albright, Armstrong, Bay Shore Units 2-4, Eastlake Units 4-5, R. Paul Smith, Rivesville and Willow Island were deactivated. FG entered into RMR arrangements with PJM for Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 through the spring of 2015, when they are scheduled to be deactivated. In February 2014, PJM notified FG that Eastlake Units 1-3 and Lake Shore Unit 18 will be released from RMR status as of September 15, 2014. As of October 9, 2013, the Hatfield's Ferry and Mitchell stations were also deactivated.

FirstEnergy and FES have various long-term coal transportation agreements, some of which run through 2025 and certain of which are related to the plants described above. FE and FES have asserted force majeure defenses for delivery shortfalls under certain agreements, and are in discussion with the applicable counterparties. As to two agreements, FE and FES have settled monetary claims for damages for the failure to take minimum quantities for the calendar year 2012 by the payments of approximately $70 million, and agreed to pay liquidated damages for delivery shortfalls for 2013 and 2014. FE and FES recorded $67 million in liquidated damages in the fourth quarter of 2013, associated with estimated 2013 delivery shortfalls, which were paid in the first quarter of 2014. Additionally, in January 2014, FE and FES reached an agreement in principle with Mepco Holdings LLC to terminate a contract for future coal deliveries to Hatfield for $18 million, which was approved by the United States Bankruptcy Court on February 26, 2014. If FE and FES fail to reach a resolution with applicable counterparties for coal transportation agreements associated with the deactivated plants or unresolved aspects of the transportation agreements and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses do not excuse delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted.

Climate Change

There are a number of initiatives to reduce GHG emissions under consideration at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs to control emissions of certain GHGs. In his 2013 State of the Union address, President Obama called for Congressional action on GHG emissions indicating his administration will take action in the event Congress fails to act. In June 2013, the President's Climate Action Plan outlined Executive action to: (1) cut carbon pollution in America, including the EPA carbon pollution standards for both new and existing power plants by 17% by 2020 (from 2005 levels); (2) prepare the United States for the impacts of climate change; and (3) lead international efforts to combat global climate change and prepare for its impacts.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required the measurement and reporting of GHG emissions commencing in 2010. In December 2009, the EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act." The EPA's finding concludes that concentrations of several

key GHGs increase the threat of climate change and may be regulated as “air pollutants” under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of CO_2 equivalents for existing facilities under the CAA's PSD program. On April 13, 2012, the EPA proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units that are larger than 25 MW, which were ultimately withdrawn. On June 25, 2013, a Presidential memorandum directed the EPA to complete, in a timely fashion, proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units, starting with re-proposal by September 20, 2013. The memorandum further directed the EPA to propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel generating units. On September 20, 2013, the EPA proposed a new source performance standard of 1,000 lbs. CO_2/MWH for large natural gas fired units (> 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for other natural gas fired units (≤ 850 mmBTU/hr), and 1,100 lbs. CO_2/MWH for fossil fuel fired units which would require partial carbon capture and storage. On October 15, 2013, the U.S. Supreme Court agreed to review a June 2012 D.C. Circuit Court of Appeals decision upholding the EPA's May 2010 regulations to decide a single narrow question: "Whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases?" Oral argument was held on February 24, 2014. Depending on the outcome of these proceedings and how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

At the international level, the Kyoto Protocol, signed by the U.S. in 1998 but never submitted for ratification by the U.S. Senate, was intended to address global warming by reducing the amount of man-made GHG, including CO_2, emitted by developed countries by 2012. A December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement that recognized the scientific view that the increase in global temperature should be below two degrees Celsius; includes a commitment by developed countries to provide funds, approaching $30 billion over three years with a goal of increasing to $100 billion by 2020; and establishes the “Green Climate Fund” to support mitigation, adaptation, and other climate-related activities in developing countries. To the extent that they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia and the United States, would commit to quantified economy-wide emissions targets by 2020, while developing countries, including Brazil, China and India, would agree to take mitigation actions, subject to their domestic measurement, reporting and verification. In December 2010, the U.N. Climate Change Conference in Cancun, Mexico resulted in an acknowledgment to reduce emissions from industrialized countries by 25 to 40 percent from 1990 emissions by 2020 and support enhanced action on climate change in the developing world. In December 2011 the U.N. Climate Change Conference in Durban, South Africa, established a negotiating process to develop a new post-2020 climate change protocol, called the “Durban Platform for Enhanced Action”. This negotiating process contemplates developed countries, as well as developing countries such as China, India, Brazil, and South Africa, to undertake legally binding commitments post-2020. In addition, certain countries agreed to extend the Kyoto Protocol for a second commitment period, commencing in 2013 and expiring in 2018 or 2020. In December 2012, the U.N. Climate Change Conference in Doha, Qatar, resulted in countries agreeing to a new commitment period under the Kyoto Protocol beginning in 2020. The new Doha Amendment to establish a second commitment period requires the ratification of three-quarters of the parties to the Kyoto Protocol before it becomes effective.

FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

In 2004, the EPA established new performance standards under Section 316(b) of the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). In 2007, the U.S. Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and the EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit's opinion and decided that Section 316(b) of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the CWA to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. The period for finalizing the Section 316(b) regulation was extended to April 17, 2014 under a Settlement Agreement between EPA and certain NGOs. FirstEnergy is studying various control options and their

costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant's water intake channel to divert fish away from the plant's water intake system. Depending on the results of such studies and the EPA's further rulemaking and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

On April 19, 2013, the EPA proposed regulatory changes to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423). The EPA proposed eight treatment options for waste water discharges from electric power plants, of which four are "preferred" by the Agency. The preferred options range from more stringent chemical and biological treatment requirements to zero discharge requirements. The EPA is required to finalize this rulemaking by May 22, 2014, under a consent decree entered by a U.S. District Court and the treatment obligations are proposed to phase-in as waste water discharge permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule, the future costs of compliance with these standards may require material capital expenditures.

In October 2009, the WVDEP issued an NPDES water discharge permit for the Fort Martin Plant, which imposes TDS, sulfate concentrations and other effluent limitations for heavy metals, as well as temperature limitations. Concurrent with the issuance of the Fort Martin NPDES permit, WVDEP also issued an administrative order setting deadlines for MP to meet certain of the effluent limits that were effective immediately under the terms of the NPDES permit. MP appealed, and a stay of certain conditions of the NPDES permit and order have been granted pending a final decision on the appeal and subject to WVDEP moving to dissolve the stay. The Fort Martin NPDES permit could require an initial capital investment ranging from $150 million to $300 million in order to install technology to meet the TDS and sulfate limits, which technology may also meet certain of the other effluent limits. Additional technology may be needed to meet certain other limits in the Fort Martin NPDES permit. MP intends to vigorously pursue these issues but cannot predict the outcome of these appeals or estimate the possible loss or range of loss.

In December 2010, PA DEP submitted its CWA 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. In May 2011, the EPA agreed with PA DEP's recommended sulfate impairment designation which requires the development of a TMDL limit for the river, a process that will take PA DEP approximately five years. Based on the stringency of the TMDL, MP may incur significant costs to reduce sulfate discharges into the Monongahela River if the NPDES permit for the coal-fired Fort Martin plant in West Virginia is required to be modified or renewed to include more stringent effluent limitations for sulfate. However, the Hatfield's Ferry and Mitchell Plants in Pennsylvania that discharge into the Monongahela River were deactivated on October 9, 2013.

FirstEnergy intends to vigorously defend against the CWA matters described above but, except as indicated above, cannot predict their outcomes or estimate the possible loss or range of loss.

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA of 1976, as amended, and the Toxic Substances Control Act of 1976. Certain fossil-fuel combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2009, in an advance notice of public rulemaking, the EPA asserted that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of coal combustion residuals, including the option of regulation as a special waste under the EPA's hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of coal combustion residuals. On April 19, 2013, the EPA stated it would "align" its proposed coal combustion residuals regulations with revised waste water discharge effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) that were proposed on that date. On July 25, 2013, the House of Representatives passed H.R. 221 that would require CCRs to be regulated under Subtitle D of RCRA, as non-hazardous. On January 29, 2014, EPA agreed to take final action by December 19, 2014 on whether or not to pursue the proposed non-hazardous waste option for regulating CCRs in a Consent Decree to be filed in pending litigation. Depending on the content of the EPA's final effluent limitations rule, the specifics of any "alignment", whether EPA chooses to pursue the non-hazardous or hazardous waste option and the enactment of legislation, the future costs of compliance with such standards may require material capital expenditures.

On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a Consent Decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified Consent Decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified Consent Decree also requires payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On February 1, 2013, FG submitted a Feasibility Study analyzing various technical issues relevant to the closure of LBR. On March 28, 2013, FG submitted to the PA DEP a Closure Plan Major Permit Modification Application which provides for placing a final cap over LBR that would require 15 years to fully implement following the closure of LBR. The estimated cost for the proposed closure plan is $234 million, including environmental and other post closure costs. On October 3, 2013, the PA DEP issued a technical deficiency letter citing four main deficiencies with the Closure Plan: (1) seeking to accelerate the 15 year period proposed by FG for closure activities to complete closure in 9 years by commencing closure activities prior to 2017 as

proposed by FG; (2) seeking to extend bond closure and post closure activities beyond the 45 years proposed by FG; (3) seeking active dewatering of the CCBs in areas where there are seeps impacted by the Impoundment; and (4) seeking an abatement plan for groundwater impacted by arsenic. FG responded to the PA DEP on December 3, 2013, and as a result of the Closure Plan, FG increased its asset retirement obligation for LBR by $163 million in 2013. The Bruce Mansfield Plant is pursuing several options for its CCBs following December 31, 2016, and on January 23, 2013, announced a plan for beneficial use of its CCBs for mine reclamation in LaBelle, Pennsylvania. In June 2013, a complaint filed in the U.S. District Court for the Western District of Pennsylvania, alleges the LaBelle site is in violation of RCRA and state laws. In addition, on December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR.

On October 10, 2013 and December 5, 2013, complaints were filed on behalf of approximately 50 individuals against FE, FG and FES in the U.S. District Court for the Northern District of West Virginia and approximately 15 individuals against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages for alleged property damage, bodily injury and emotional distress related to the LBR CCB Impoundment. The complaints state claims for private nuisance, negligence, negligence per se, reckless conduct and trespass related to alleged groundwater contamination and odors emanating from the Impoundment. FE, FG and FES believe the claims are without merit and intend to vigorously defend themselves against the allegations made in the complaints, but, at this time, are unable to predict the outcome of the above matter or estimate the possible loss or range of loss.

FirstEnergy's future cost of compliance with any coal combustion residuals regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

Certain of FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2013 based on estimates of the total costs of cleanup, FE's and its subsidiaries' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $128 million have been accrued through December 31, 2013. Included in the total are accrued liabilities of approximately $82 million for environmental remediation of former manufactured gas plants and gas holder facilities in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC. FirstEnergy or its subsidiaries could be found potentially responsible for additional amounts or additional sites, but the possible losses or range of losses cannot be determined or reasonably estimated at this time.

OTHER LEGAL PROCEEDINGS

Nuclear Plant Matters

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2013, FirstEnergy had approximately $2.2 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDT fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDT. FE maintains a $125 million parental guaranty relating to a potential shortfall in nuclear decommissioning funding for Beaver Valley Unit 1 and Perry. FE also maintains an $11 million parental guaranty in support of the decommissioning of the spent fuel storage facilities located at its Davis-Besse and Perry nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranty, as appropriate.

On October 4, 2013, during a refueling outage for Beaver Valley Unit 1, FENOC conducted a planned visual examination of the interior containment liner and coatings. The containment design for Beaver Valley includes an interior steel liner that is surrounded by reinforced concrete. A penetration through the containment steel liner plate of approximately 0.4 inches by 0.28 inches was discovered. A detailed investigation was initiated, including laboratory analysis that has indicated that the degraded area was initiated by foreign material inadvertently left in the concrete during construction. An assessment has been performed which concluded that any postulated leakage through the affected area was within overall allowable limits for the containment building. The structural integrity of the containment building is not affected. Repair of the containment liner was completed and Unit 1 was returned to service on November 4, 2013.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. An NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of petitioners. On July 9, 2012, the petitioners' proposed a contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding. In an order dated August 7, 2012, the NRC stated that it will not issue final licensing decisions until it has appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance. The ASLB has suspended further consideration of the petitioners' proposed contention on the environmental impacts of spent fuel storage at Davis-Besse. The NRC Staff issued Waste Confidence Draft Generic Environmental Impact Statement and published a proposed rule on this subject in September of 2013. Other contentions proposed by the petitioners in this proceeding have been rejected by the ASLB. On February 18, 2014, Beyond Nuclear and Don't Waste Michigan, two of the petitioners in the Davis-Besse license renewal proceeding, requested that the NRC institute a rulemaking

on the environmental impacts of high density spent fuel storage and mitigation alternatives. On February 27, 2014, these petitioners requested a suspension of the licensing decision in the Davis-Besse license renewal proceeding to allow the NRC to complete this rulemaking.

As part of routine inspections of the concrete shield building at Davis-Besse Nuclear Power Station in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. The shield building is a 2 1/2-foot thick reinforced concrete structure that provides biological shielding, protection from natural phenomena including wind and tornadoes and additional shielding in the event of an accident. FENOC then expanded its sample size to include all of the existing core bores in the shield building. These inspections, which are now complete, identified additional subsurface cracking that was determined to be pre-existing, but only now identified with the aid of improved inspection technology. These inspections also revealed that the cracking condition has propagated a small amount in select areas. Preliminary analysis of the inspections results confirm that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions.

On February 1, 2014, the Davis-Besse Nuclear Power Station entered into an outage to install two new steam generators, replace about a third of the unit’s 177 fuel assemblies and perform numerous safety inspections and preventative maintenance activities. During the preliminary stages of the outage an area of concrete that was not filled to the expected thickness within the shield building wall was discovered at the top of the temporary construction opening that was created as part of the 2011 outage. The 2011 temporary construction opening was created to install the new reactor head. FENOC has assessed the as-found condition of the concrete and has determined the shield building would have performed its design functions. This condition within the shield building wall will be repaired during this outage to conform to its original design configuration. This condition is not expected to extend the outage.

On March 12, 2012, the NRC issued orders requiring safety enhancements at U.S. reactors based on recommendations from the lessons learned Task Force review of the accident at Japan's Fukushima Daiichi nuclear power plant. These orders require additional mitigation strategies for beyond-design-basis external events, and enhanced equipment for monitoring water levels in spent fuel pools. The NRC also requested that licensees including FENOC: re-analyze earthquake and flooding risks using the latest information available; conduct earthquake and flooding hazard walkdowns at their nuclear plants; assess the ability of current communications systems and equipment to perform under a prolonged loss of onsite and offsite electrical power; and assess plant staffing levels needed to fill emergency positions. These and other NRC requirements adopted as a result of the accident at Fukushima Daiichi are likely to result in additional material costs from plant modifications and upgrades at FENOC's nuclear facilities.

ICG Litigation

On December 28, 2006, AE Supply and MP filed a complaint in the Court of Common Pleas of Allegheny County, Pennsylvania against ICG, Anker WV, and Anker Coal. Anker WV entered into a long term Coal Sales Agreement with AE Supply and MP for the supply of coal to the Harrison generating facility. Prior to the time of trial, ICG was dismissed as a defendant by the Court, which issue can be the subject of a future appeal. As a result of defendants' past and continued failure to supply the contracted coal, AE Supply and MP have incurred and will continue to incur significant additional costs for purchasing replacement coal. A non-jury trial was held from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they have incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. Defendants primarily claim that their performance is excused under a force majeure clause in the coal sales agreement and presented evidence at trial that they will continue to not provide the contracted yearly tonnage amounts. On May 2, 2011, the court entered a verdict in favor of AE Supply and MP for $104 million ($90 million in future damages and $14 million for replacement coal/interest). On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that the defendants still owed future damages, it remanded the calculation of those damages back to the trial court. The specific amount of those future damages is not known at this time, but they are expected to be calculated at a market price of coal that is significantly lower than the price used by the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on November 19, 2012. On July 2, 2013, the Petition for Allowance of Appeal was denied and in the second quarter of 2013 the now final past damage award of $15.5 million (including interest) was recognized. The case was sent back to the trial court to recalculate the future damages only and is currently in the discovery phase. A hearing is scheduled for May 13-14, 2014.

Other Legal Matters

In 2010, a lawsuit was filed in Allegheny County Court of Common Pleas by Michael Goretzka, for wrongful death and negligence after his wife was fatally electrocuted when she contacted a downed power line. The trial resulted in a verdict against WP and the parties settled this matter. WP's portion of the settlement was covered by insurance subject to the remainder of its deductible. On May 30, 2012, the PPUC's Bureau of Investigation and Enforcement (I&E) filed a Formal Complaint at the PPUC regarding this matter. On February 13, 2013, WP and I&E filed a Joint Petition for Full Settlement that includes, among other things, WP's agreement to conduct an infrared inspection of its primary distribution system, modify certain training programs, and pay an $86,000 civil penalty, which settlement is subject to PPUC approval. On August 29, 2013, the PPUC entered an Order granting the Goretzka family limited party status for the sole purpose of submitting comments to the settlement and issuing the settlement for comment

by the parties. On September 16, 2013, the Goretzka family filed Limited Objections to the settlement. Reply comments were filed by WP on September 30, 2013. The PPUC entered an Opinion and Order on January 9, 2014 approving the Settlement with limited modifications regarding the frequency of refresher training and reporting obligations. WP filed a letter on January 17, 2014 accepting those modifications and noting its intent to begin implementation of the settlement terms.

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The loss or range of loss in these matters is not expected to be material to FirstEnergy or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 15, Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

FirstEnergy accrues legal liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. In cases where FirstEnergy determines that it is not probable, but reasonably possible that it has a material obligation, it discloses such obligations and the possible loss or range of loss if such estimate can be made. If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on any of the matters referenced above, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

17. TRANSACTIONS WITH AFFILIATED COMPANIES

FES' operating revenues, operating expenses, investment income and interest expenses include transactions with affiliated companies. These affiliated company transactions include affiliated company power sales agreements between FirstEnergy's competitive and regulated companies, support service billings, interest on affiliated company notes including the money pools and other transactions.

FirstEnergy's competitive companies at times provide power through affiliated company power sales to meet a portion of the Utilities' POLR and default service requirements. The primary affiliated company transactions for FES during the three years ended December 31, 2013 are as follows:

FES	2013	2012	2011
	(In millions)		
Revenues:			
Electric sales to affiliates	$ 652	$ 515	$ 752
Other	6	16	80
Expenses:			
Purchased power from affiliates	486	451	242
Fuel	—	2	37
Support services	619	570	655
Investment Income:			
Interest income from FE	2	2	2
Interest Expense:			
Interest expense to affiliates	4	10	8
Interest expense to FE	6	1	1

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to FES and the Utilities from FESC, AESC and FENOC. The majority of costs are directly billed or assigned at no more than cost. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas developed by FESC, AESC and FENOC. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Management believes that these allocation methods are reasonable. Intercompany transactions are generally settled under commercial terms within thirty days. FES purchases the entire output of the generation facilities owned by FG and NG, and may purchase the uncommitted output of AE Supply, as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are subject to sale and leaseback arrangements, and pursuant to full output, cost-of-service PSAs.

FES and the Utilities are parties to an intercompany income tax allocation agreement with FirstEnergy and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FirstEnergy are generally reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit (see Note 5, Taxes).

18. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FG completed a sale and leaseback transaction for its undivided interest in Bruce Mansfield Unit 1. FES has fully and unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FG, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty. This transaction is classified as an operating lease for FES and FirstEnergy and as a financing lease for FG.

The Condensed Consolidating Statements of Income (Loss) and Comprehensive Income (Loss) for the years ended December 31, 2013, 2012, and 2011, Condensed Consolidating Balance Sheets as of December 31, 2013 and December 31, 2012, and Condensed Consolidating Statements of Cash Flows for the years ended December 31, 2013, 2012, and 2011, for FES (parent and guarantor), FG and NG (non-guarantor) are presented below. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FG and NG are, therefore, reflected in FES' investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)
(Unaudited)

For the Year Ended December 31, 2013	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 6,068	$ 2,399	$ 1,634	$ (3,928)	$ 6,173
OPERATING EXPENSES:					
Fuel	—	1,056	206	—	1,262
Purchased power from affiliates	4,148	—	266	(3,928)	486
Purchased power from non-affiliates	2,326	7	—	—	2,333
Other operating expenses	635	275	529	48	1,487
Pensions and OPEB mark-to-market adjustments	(8)	(37)	(36)	—	(81)
Provision for depreciation	6	127	178	(5)	306
General taxes	80	34	24	—	138
Total operating expenses	7,187	1,462	1,167	(3,885)	5,931
OPERATING INCOME (LOSS)	(1,119)	937	467	(43)	242
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(103)	—	—	—	(103)
Investment income	5	1	25	(15)	16
Miscellaneous income, including net income from equity investees	846	24	—	(842)	28
Interest expense — affiliates	(13)	(5)	(6)	14	(10)
Interest expense — other	(63)	(104)	(54)	61	(160)
Capitalized interest	1	2	36	—	39
Total other income (expense)	673	(82)	1	(782)	(190)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(446)	855	468	(825)	52
INCOME TAXES (BENEFITS)	(506)	365	135	12	6
INCOME FROM CONTINUING OPERATIONS	60	490	333	(837)	46
Discontinued operations (net of income taxes of $8)	—	14	—	—	14
NET INCOME	$ 60	$ 504	$ 333	$ (837)	$ 60
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 60	$ 504	$ 333	$ (837)	$ 60
OTHER COMPREHENSIVE LOSS:					
Pensions and OPEB prior service costs	(15)	(13)	—	13	(15)
Amortized gain on derivative hedges	(6)	—	—	—	(6)
Change in unrealized gain on available-for-sale securities	(8)	—	(8)	8	(8)
Other comprehensive loss	(29)	(13)	(8)	21	(29)
Income tax benefits on other comprehensive loss	(11)	(5)	(3)	8	(11)
Other comprehensive loss, net of tax	(18)	(8)	(5)	13	(18)
COMPREHENSIVE INCOME	$ 42	$ 496	$ 328	$ (824)	$ 42

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

For the Year Ended December 31, 2012	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 5,804	$ 2,100	$ 1,895	$ (3,905)	$ 5,894
OPERATING EXPENSES:					
Fuel	—	1,077	210	—	1,287
Purchased power from affiliates	4,098	—	258	(3,905)	451
Purchased power from non-affiliates	1,881	6	—	—	1,887
Other operating expenses	434	334	539	49	1,356
Pensions and OPEB mark-to-market adjustments	(2)	52	116	—	166
Provision for depreciation	4	116	157	(5)	272
General taxes	79	36	21	—	136
Total operating expenses	6,494	1,621	1,301	(3,861)	5,555
OPERATING INCOME (LOSS)	(690)	479	594	(44)	339
OTHER INCOME (EXPENSE):					
Investment income	2	15	67	(18)	66
Miscellaneous income, including net income from equity investees	1,284	20	—	(1,269)	35
Interest expense — affiliates	(18)	(7)	(4)	19	(10)
Interest expense — other	(93)	(110)	(50)	62	(191)
Capitalized interest	—	4	33	—	37
Total other income (expense)	1,175	(78)	46	(1,206)	(63)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	485	401	640	(1,250)	276
INCOME TAXES (BENEFITS)	298	(269)	62	12	103
INCOME FROM CONTINUING OPERATIONS	187	670	578	(1,262)	173
Discontinued operations (net of income taxes of $8)	—	14	—	—	14
NET INCOME	$ 187	$ 684	$ 578	$ (1,262)	$ 187
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$ 187	$ 684	$ 578	$ (1,262)	$ 187
OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	6	6	—	(6)	6
Amortized gain on derivative hedges	(9)	—	—	—	(9)
Change in unrealized gain on available-for-sale securities	(5)	—	(5)	5	(5)
Other comprehensive income (loss)	(8)	6	(5)	(1)	(8)
Income taxes (benefits) on other comprehensive income (loss)	(4)	1	(2)	1	(4)
Other comprehensive income (loss), net of tax	(4)	5	(3)	(2)	(4)
COMPREHENSIVE INCOME	$ 183	$ 689	$ 575	$ (1,264)	$ 183

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)
(Unaudited)

For the Year Ended December 31, 2011	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
STATEMENTS OF INCOME					
REVENUES	$ 5,387	$ 2,642	$ 1,647	$ (4,223)	$ 5,453
OPERATING EXPENSES:					
Fuel	12	1,138	194	—	1,344
Purchased power from affiliates	4,208	5	252	(4,223)	242
Purchased power from non-affiliates	1,378	3	—	—	1,381
Other operating expenses	574	416	578	51	1,619
Pensions and OPEB mark-to-market adjustments	10	68	93	—	171
Provision for depreciation	4	124	150	(6)	272
General taxes	64	37	23	—	124
Impairment of long-lived assets	—	294	—	—	294
Total operating expenses	6,250	2,085	1,290	(4,178)	5,447
OPERATING INCOME (LOSS)	(863)	557	357	(45)	6
OTHER INCOME (EXPENSE):					
Investment income	1	—	56	—	57
Miscellaneous income, including net income from equity investees	924	24	—	(918)	30
Interest expense — affiliates	(2)	(3)	(2)	(1)	(8)
Interest expense — other	(94)	(109)	(64)	64	(203)
Capitalized interest	—	12	23	—	35
Total other income (expense)	829	(76)	13	(855)	(89)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(34)	481	370	(900)	(83)
INCOME TAXES (BENEFITS)	25	(117)	58	18	(16)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(59)	598	312	(918)	(67)
Discontinued operations (net of income taxes of $5)	—	8	—	—	8
NET INCOME (LOSS)	$ (59)	$ 606	$ 312	$ (918)	$ (59)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$ (59)	$ 606	$ 312	$ (918)	$ (59)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	(12)	(13)	—	13	(12)
Amortized loss on derivative hedges	12	—	—	—	12
Change in unrealized gain on available-for-sale securities	16	—	15	(15)	16
Other comprehensive income (loss)	16	(13)	15	(2)	16
Income taxes (benefits) on other comprehensive income (loss)	2	(8)	5	3	2
Other comprehensive income (loss), net of tax	14	(5)	10	(5)	14
COMPREHENSIVE INCOME (LOSS)	$ (45)	$ 601	$ 322	$ (923)	$ (45)

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of December 31, 2013	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 2	$ —	$ —	$ 2
Receivables-					
Customers	539	—	—	—	539
Affiliated companies	938	787	227	(916)	1,036
Other	52	12	17	—	81
Notes receivable from affiliated companies	203	23	683	(909)	—
Materials and supplies	76	159	213	—	448
Derivatives	165	—	—	—	165
Prepayments and other	81	50	7	—	138
	2,054	1,033	1,147	(1,825)	2,409
PROPERTY, PLANT AND EQUIPMENT:					
In service	104	6,105	6,645	(382)	12,472
Less — Accumulated provision for depreciation	28	1,953	2,962	(188)	4,755
	76	4,152	3,683	(194)	7,717
Construction work in progress	23	148	1,137	—	1,308
	99	4,300	4,820	(194)	9,025
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,276	—	1,276
Investment in affiliated companies	5,801	—	—	(5,801)	—
Other	—	11	—	—	11
	5,801	11	1,276	(5,801)	1,287
ASSETS HELD FOR SALE (Note 20)	—	122	—	—	122
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	—	131	—	(131)	—
Customer intangibles	95	—	—	—	95
Goodwill	23	—	—	—	23
Property taxes	—	15	26	—	41
Unamortized sale and leaseback costs	—	—	—	168	168
Derivatives	53	—	—	—	53
Other	188	228	18	(155)	279
	359	374	44	(118)	659
	$ 8,313	$ 5,840	$ 7,287	$ (7,938)	$ 13,502
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 1	$ 367	$ 547	$ (23)	$ 892
Short-term borrowings-					
Affiliated companies	977	212	151	(909)	431
Other	—	4	—	—	4
Accounts payable-					
Affiliated companies	741	400	362	(738)	765
Other	94	196	—	—	290
Accrued taxes	204	23	23	(184)	66
Derivatives	110	—	—	—	110
Other	70	63	18	46	197
	2,197	1,265	1,101	(1,808)	2,755
CAPITALIZATION:					
Total equity	5,312	2,283	3,493	(5,776)	5,312
Long-term debt and other long-term obligations	712	1,860	742	(1,184)	2,130
	6,024	4,143	4,235	(6,960)	7,442
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	858	858
Accumulated deferred income taxes	32	—	736	(27)	741
Asset retirement obligations	—	187	828	—	1,015
Retirement benefits	22	163	—	—	185
Derivatives	14	—	—	—	14
Other	24	82	387	(1)	492
	92	432	1,951	830	3,305
	$ 8,313	$ 5,840	$ 7,287	$ (7,938)	$ 13,502

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of December 31, 2012	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ —	$ 3	$ —	$ —	$ 3
Receivables-					
Customers	483	—	—	—	483
Affiliated companies	232	417	478	(748)	379
Other	56	19	16	—	91
Notes receivable from affiliated companies	366	7	607	(704)	276
Materials and supplies	66	231	208	—	505
Derivatives	158	—	—	—	158
Prepayments and other	38	39	10	—	87
	1,399	716	1,319	(1,452)	1,982
PROPERTY, PLANT AND EQUIPMENT:					
In service	91	5,899	6,391	(384)	11,997
Less — Accumulated provision for depreciation	32	1,915	2,646	(185)	4,408
	59	3,984	3,745	(199)	7,589
Construction work in progress	34	230	877	—	1,141
	93	4,214	4,622	(199)	8,730
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,283	—	1,283
Investment in affiliated companies	4,972	—	—	(4,972)	—
Other	—	12	—	—	12
	4,972	12	1,283	(4,972)	1,295
ASSETS HELD FOR SALE	—	—	—	—	—
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	—	313	—	(313)	—
Customer intangibles	110	—	—	—	110
Goodwill	24	—	—	—	24
Property taxes	—	14	22	—	36
Unamortized sale and leaseback costs	—	—	—	119	119
Derivatives	99	—	—	—	99
Other	160	194	5	(106)	253
	393	521	27	(300)	641
	$ 6,857	$ 5,463	$ 7,251	$ (6,923)	$ 12,648
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$ 1	$ 586	$ 537	$ (22)	$ 1,102
Short-term borrowings-					
Affiliated companies	358	346	—	(704)	—
Other	—	4	—	—	4
Accounts payable-					
Affiliated companies	748	143	583	(748)	726
Other	63	96	—	—	159
Accrued taxes	126	25	20	—	171
Derivatives	124	—	—	—	124
Other	71	148	15	46	280
	1,491	1,348	1,155	(1,428)	2,566
CAPITALIZATION:					
Total equity	3,763	1,787	3,165	(4,952)	3,763
Long-term debt and other long-term obligations	1,482	2,009	834	(1,207)	3,118
	5,245	3,796	3,999	(6,159)	6,881
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	892	892
Accumulated deferred income taxes	28	—	714	(227)	515
Asset retirement obligations	—	29	936	—	965
Retirement benefits	26	215	—	—	241
Derivatives	37	—	—	—	37
Other	30	75	447	(1)	551
	121	319	2,097	664	3,201
	$ 6,857	$ 5,463	$ 7,251	$ (6,923)	$ 12,648

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Year Ended December 31, 2013	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (1,429)	$ 753	$ 776	$ (22)	$ 78
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	864	371	150	(954)	431
Equity contribution from parent	1,500	—	—	—	1,500
Redemptions and Repayments-					
Long-term debt	(770)	(364)	(90)	22	(1,202)
Short-term borrowings, net	(244)	(505)	—	749	—
Tender premiums	(67)	—	—	—	(67)
Other	(4)	(5)	—	—	(9)
Net cash provided from (used for) financing activities	1,279	(503)	60	(183)	653
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(12)	(256)	(449)	—	(717)
Nuclear fuel	—	—	(250)	—	(250)
Proceeds from asset sales	—	21	—	—	21
Sales of investment securities held in trusts	—	—	940	—	940
Purchases of investment securities held in trusts	—	—	(1,000)	—	(1,000)
Loans to affiliated companies, net	163	(15)	(77)	205	276
Other	(1)	(1)	—	—	(2)
Net cash provided from (used for) investing activities	150	(251)	(836)	205	(732)
Net change in cash and cash equivalents	—	(1)	—	—	(1)
Cash and cash equivalents at beginning of period	—	3	—	—	3
Cash and cash equivalents at end of period	$ —	$ 2	$ —	$ —	$ 2

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Year Ended December 31, 2012	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (1,063)	$ 639	$ 1,266	$ (21)	$ 821
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	351	299	—	650
Short-term borrowings, net	—	260	—	(257)	3
Redemptions and Repayments-					
Long-term debt	(1)	(288)	(161)	21	(429)
Short-term borrowings, net	(707)	—	(32)	739	—
Common stock dividend payment	—	(2,000)	—	2,000	—
Other	(1)	(8)	(3)	—	(12)
Net cash provided from (used for) financing activities	(709)	(1,685)	103	2,503	212
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(14)	(273)	(508)	—	(795)
Nuclear fuel	—	—	(286)	—	(286)
Proceeds from asset sales	—	17	—	—	17
Sales of investment securities held in trusts	—	—	1,464	—	1,464
Purchases of investment securities held in trusts	—	—	(1,502)	—	(1,502)
Loans to affiliated companies, net	(211)	1,338	(538)	(482)	107
Dividend received	2,000	—	—	(2,000)	—
Other	(3)	(40)	1	—	(42)
Net cash provided from (used for) investing activities	1,772	1,042	(1,369)	(2,482)	(1,037)
Net change in cash and cash equivalents	—	(4)	—	—	(4)
Cash and cash equivalents at beginning of period	—	7	—	—	7
Cash and cash equivalents at end of period	$ —	$ 3	$ —	$ —	$ 3

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

For the Year Ended December 31, 2011	FES	FG	NG	Eliminations	Consolidated
			(In millions)		
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$ (790)	$ 926	$ 702	$ (19)	$ 819
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	140	107	—	247
Redemptions and Repayments-					
Long-term debt	(136)	(362)	(377)	19	(856)
Short-term borrowings, net	1,065	78	32	(1,186)	(11)
Other	(9)	(1)	(1)	—	(11)
Net cash provided from (used for) financing activities	920	(145)	(239)	(1,167)	(631)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(24)	(205)	(371)	—	(600)
Nuclear fuel	—	—	(149)	—	(149)
Proceeds from asset sales	9	590	—	—	599
Sales of investment securities held in trusts	—	—	1,843	—	1,843
Purchases of investment securities held in trusts	—	—	(1,890)	—	(1,890)
Loans to affiliated companies, net	(120)	(1,157)	105	1,186	14
Other	5	(11)	(1)	—	(7)
Net cash used for investing activities	(130)	(783)	(463)	1,186	(190)
Net change in cash and cash equivalents	—	(2)	—	—	(2)
Cash and cash equivalents at beginning of period	—	9	—	—	9
Cash and cash equivalents at end of period	$ —	$ 7	$ —	$ —	$ 7

19. SEGMENT INFORMATION

Financial information for each of FirstEnergy's reportable segments is presented in the tables below. FES does not have separate reportable operating segments.

The Regulated Distribution segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also includes regulated electric generation facilities in West Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. Its results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls approximately 3,780 MWs of generation capacity, including the net transfer to Regulated Distribution of 1,476 MWs of capacity associated with the Harrison and Pleasants asset swap which occurred on October 9, 2013.

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP) and the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from rates that recover costs and provide a return on transmission capital investment. Except for the recovery of the PATH abandoned project regulatory asset, these revenues are derived from transmission services provided pursuant to the PJM open access transmission tariff to LSEs. Its results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Competitive Energy Services segment, through FES and AE Supply, supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls approximately 14,000 MWs of capacity, including 885 MWs of capacity subject to RMR arrangements with PJM and excluding 1,476 MWs of generation capacity transferred to Regulated Distribution in connection with the Harrison and Pleasants asset swap that occurred on October 9, 2013. This segment also purchases electricity to meet sales obligations. The segment's net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs charged by PJM to deliver energy to the segment's customers.

The Other/Corporate Segment contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment. Reconciling adjustments primarily consist of elimination of intersegment transactions.

Segment Financial Information

For the Years Ended December 31,	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other/ Corporate	Reconciling Adjustments	Consolidated
			(In millions)			
2013						
External revenues	$ 8,738	$ 741	$ 5,725	$ (121)	$ (166)	$ 14,917
Internal revenues	—	—	770	—	(770)	—
Total revenues	8,738	741	6,495	(121)	(936)	14,917
Depreciation, amortization and deferrals	1,135	124	439	43	—	1,741
Investment income	57	—	14	9	(44)	36
Interest expense	543	93	222	158	—	1,016
Income taxes (benefits)	301	129	(141)	(78)	(16)	195
Income (loss) from continuing operations	501	214	(237)	(130)	27	375
Discontinued operations, net of tax	—	—	17	—	—	17
Net income (loss)	501	214	(220)	(130)	27	392
Total assets	27,683	5,247	16,782	712	—	50,424
Total goodwill	5,092	526	800	—	—	6,418
Property additions	1,272	461	827	78	—	2,638
2012						
External revenues	$ 9,060	$ 740	$ 5,778	$ (119)	$ (188)	$ 15,271
Internal revenues	—	—	866	—	(864)	2
Total revenues	9,060	740	6,644	(119)	(1,052)	15,273
Depreciation, amortization and deferrals	493	111	409	38	—	1,051
Investment income (loss)	84	1	66	(5)	(69)	77
Interest expense	540	92	284	85	—	1,001
Income taxes (benefits)	295	133	83	(34)	68	545
Income (loss) from continuing operations	540	226	199	(155)	(55)	755
Discontinued operations, net of tax	—	—	16	—	—	16
Net income (loss)	540	226	215	(155)	(55)	771
Total assets	27,150	4,865	18,087	392	—	50,494
Total goodwill	5,025	526	896	—	—	6,447
Property additions	1,074	507	1,014	83	—	2,678
2011						
External revenues	$ 9,913	$ 660	$ 5,783	$ (114)	$ (204)	$ 16,038
Internal revenues	—	—	1,237	—	(1,170)	67
Total revenues	9,913	660	7,020	(114)	(1,374)	16,105
Depreciation, amortization and deferrals	846	110	411	24	—	1,391
Investment income	99	—	56	1	(42)	114
Interest expense	530	89	298	91	—	1,008
Income taxes (benefits)	287	114	214	(87)	38	566
Income (loss) from continuing operations	488	194	364	(149)	(41)	856
Discontinued operations, net of tax	—	—	13	—	—	13
Net income (loss)	488	194	377	(149)	(41)	869
Total assets	25,534	4,463	16,796	617	—	47,410
Total goodwill	5,025	526	890	—	—	6,441
Property additions	868	390	778	93	—	2,129

20. DISCONTINUED OPERATIONS AND ASSETS HELD FOR SALE

On September 4, 2013, certain of FirstEnergy's subsidiaries applied for authorization from the FERC to sell eleven hydroelectric power stations in Pennsylvania, Virginia and West Virginia to subsidiaries of Harbor Hydro, a subsidiary of LS Power. The asset purchase agreement was entered into on August 23, 2013, and amended and restated as of September 4, 2013. On February 12, 2014, the sale of the hydroelectric power plants to LS Power closed for approximately $395 million.

As of December 31, 2013, FirstEnergy classified the hydroelectric power stations, with a carrying value of $235 million (FES - $122 million) as Assets held for sale in the Consolidated Balance Sheets. Included in the carrying value of the assets held for sale is goodwill of $29 million (FES - $1 million) which was allocated to the hydroelectric plants to be sold. Pre-tax income for the hydroelectric facilities of $26 million, $24 million and $21 million (FES - $22 million, $22 million and $13 million) for the years ended December 31, 2013, 2012 and 2011, respectively, are reported in FirstEnergy's and FES' Consolidated Statement of Income as discontinued operations. Revenues for the hydroelectric facilities of $33 million, $30 million and $42 million (FES - $31 million, $24 million and $24 million) for years ended December 31, 2013, 2012 and 2011, respectively, are reported in FirstEnergy's and FES' Consolidated Statement of Income as discontinued operations. In the first quarter of 2014, FirstEnergy expects to recognize a pre-tax gain of approximately $145 million (FES - $177 million).

21. MERGER

Purchase Price Allocation

On February 25, 2011, the merger between FE and AE closed. Pursuant to the terms of the Agreement and Plan of Merger among FE, Merger Sub and AE, Merger Sub merged with and into AE, with AE continuing as the surviving corporation and becoming a wholly owned subsidiary of FE. As part of the merger, AE shareholders received 0.667 of a share of FE common stock for each share of AE common stock outstanding as of the date the merger was completed, and all outstanding AE equity-based employee compensation awards were converted into FE equity-based awards on the same basis.

The total consideration in the merger was based on the closing price of a share of FE common stock on February 24, 2011, the day prior to the date the merger was completed, and was calculated as follows (in millions, except per share data):

Shares of AE common stock outstanding on February 24, 2011	$	170
Exchange ratio		0.667
Number of shares of FirstEnergy common stock issued		113
Closing price of FirstEnergy common stock on February 24, 2011		38.16
Fair value of shares issued by FirstEnergy		4,327
Fair value of replacement share-based compensation awards relating to pre-merger service		27
Total consideration transferred	$	4,354

The allocation of the total consideration transferred in the merger to the assets acquired and liabilities assumed includes adjustments for the fair value of Allegheny coal contracts, energy supply contracts, emission allowances, unregulated property, plant and equipment, derivative instruments, goodwill, intangible assets, long-term debt and accumulated deferred income taxes. The allocation of the purchase price was as follows:

(In millions)		
Current assets	$	1,493
Property, plant and equipment		9,660
Investments		138
Goodwill		872
Other noncurrent assets		1,353
Current liabilities		(718)
Noncurrent liabilities		(3,450)
Long-term debt and other long-term obligations		(4,994)
	$	4,354

The allocation of purchase price in the table above reflects refinements made since the merger date in the determination of the fair values of income tax benefits, certain coal contracts and an adverse purchase power contract. This primarily resulted in an increase to property, plant and equipment, other noncurrent assets and current liabilities of approximately $4 million, $91 million and $4 million, respectively, and decreases to current assets and goodwill of $16 million and $80 million. The impact of the refinements on the amortization of purchase accounting adjustments recorded during 2011 was not significant.

The estimated fair values of the assets acquired and liabilities assumed have been determined based on the accounting guidance for fair value measurements under GAAP, which defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill. The Allegheny delivery, transmission and unregulated generation businesses have been assigned to the Regulated Distribution, Regulated Transmission and Competitive Energy Services segments, respectively. The goodwill from the merger of $872 million has been assigned to the Competitive Energy Services segment based on expected synergies from the merger. The goodwill is not deductible for tax purposes.

The valuation of the additional intangible assets and liabilities recorded as a result of the merger is as follows:

(In millions)	Preliminary Valuation	Weighted Average Amortization Period
Above market contracts:		
Energy contracts	$ 189	10 years
NUG contracts	124	25 years
Coal supply contracts	516	8 years
	829	
Below market contracts:		
NUG contracts	143	13 years
Coal supply contracts	83	7 years
Transportation contract	35	8 years
	261	
Net intangible assets	$ 568	

The fair value measurements of intangible assets and liabilities were based on significant unobservable inputs and thus represent level 3 measurements.

The fair value of Allegheny's energy, NUG and gas transportation contracts, both above-market and below-market, were estimated based on the present value of the above/below market cash flows attributable to the contracts based on the contract type, discounted by a current market interest rate consistent with the overall credit quality of the contract portfolio. The above/below market cash flows were estimated by comparing the expected cash flow based on existing contracted prices and expected volumes with the cash flows from estimated current market contract prices for the same expected volumes. The estimated current market contract prices were derived considering current market prices, such as the price of energy and transmission, miscellaneous fees and a normal profit margin. The weighted average amortization period was determined based on the expected volumes to be delivered over the life of the contract.

The fair value of coal supply contracts was determined in a similar manner as the energy, NUG and gas transportation contracts, based on the present value of the above/below market cash flows attributable to the contracts. The fair value adjustments for these contracts are being amortized based on expected deliveries under each contract. See Note 7, Intangible Assets for additional information related to Intangible assets.

In connection with the merger, FirstEnergy recorded merger transaction costs, which included change in control and other benefit payments to AE executives, of approximately $2 million ($1 million net of tax), $1 million ($1 million net of tax), $91 million ($73 million net of tax) during 2013, 2012 and 2011, respectively. These costs are included in "Other operating expenses" in the Consolidated Statements of Income.

FirstEnergy also recorded approximately $6 million ($13 million net of tax) and $93 million ($91 million net of tax) in merger integration costs during 2012 and 2011, respectively, including an inventory valuation adjustment in 2011. In connection with the merger, FirstEnergy reviewed its inventory levels as a result of combining the inventory of both companies. Following this review, FirstEnergy management determined that the combined inventory stock contained excess and duplicative items. FirstEnergy management also adopted a consistent excess and obsolete inventory practice for the combined entity. Application of the revised practice, in conjunction with those items identified as excess and duplicative, resulted in an inventory valuation adjustment of $67 million ($42 million net of tax) in the first quarter of 2011.

Revenues and earnings of Allegheny included in FirstEnergy's Consolidated Statements of Income for the periods beginning on the February 25, 2011, merger date are as follows:

(In millions, except per share amounts)	February 25 - December 31, 2011	Year Ended December 31, 2012	Year Ended December 31, 2013
Total revenues	$ 3,966	$ 4,410	$ 4,331
Earnings (Losses) Available to FirstEnergy Corp.[(1)]	$ 147	$ 356	$ (31)
Basic Earnings (Losses) Per Share	$ 0.37	$ 0.85	$ (0.07)
Diluted Earnings (Losses) Per Share	$ 0.37	$ 0.85	$ (0.07)

(1) Includes Allegheny's after-tax merger costs of $58 million, $1 million and $1 million during 2011, 2012 and 2013, respectively.

Pro Forma Financial Information

The following unaudited pro forma financial information reflects the consolidated results of operations of FirstEnergy as if the merger with AE had taken place on January 1, 2010. The unaudited pro forma information was calculated after applying FirstEnergy's accounting policies and adjusting Allegheny's results to reflect the depreciation and amortization that would have been charged assuming fair value adjustments to property, plant and equipment, debt and intangible assets had been applied on January 1, 2010, together with the consequential tax effects.

FirstEnergy and Allegheny both incurred merger-related costs that have been included in the pro forma earnings presented below. Combined pre-tax transaction costs incurred were approximately $91 million in the year ended 2011. In addition, during 2011, $93 million of pre-tax merger integration costs and $36 million of pre-tax charges from merger settlements approved by regulatory agencies were recognized.

The unaudited pro forma financial information has been presented below for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger been completed on January 1, 2010, or the future consolidated results of operations of the combined company.

(Pro forma amounts in millions, except per share amounts)	**2011**
Revenues	$ 17,449
Earnings available to FirstEnergy	$ 979
Basic Earnings Per Share	$ 2.34
Diluted Earnings Per Share	$ 2.33

22. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2013 and 2012.

FirstEnergy

CONSOLIDATED STATEMENTS OF INCOME

(In millions, except per share amounts)	2013				2012			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Revenues	$ 3,647	$ 4,036	$ 3,511	$ 3,723	$ 3,493	$ 4,052	$ 3,746	$ 3,982
Other operating expense	948	877	886	882	1,163	861	920	816
Pensions and OPEB mark-to-market	(256)	—	—	—	609	—	—	—
Provision for depreciation	293	316	300	293	285	272	284	278
Impairment of long-lived assets	322	—	473	—	—	—	—	—
Operating Income (Loss)	401	512	46	648	(39)	902	549	740
Income (loss) from continuing operations before income taxes	208	286	(230)	306	(258)	729	307	522
Income taxes (benefits)	66	77	(62)	114	(105)	307	123	220
Income (loss) from continuing operations	142	209	(168)	192	(153)	422	184	302
Discontinued operations (net of income taxes)	—	9	4	4	5	3	4	4
Net Income (Loss)	142	218	(164)	196	(148)	425	188	306
Earnings (loss) available to FirstEnergy Corp.	142	218	(164)	196	(148)	425	187	306
Earnings (loss) per share of common stock-								
Basic - Continuing Operations	0.34	0.50	(0.40)	0.46	(0.36)	1.01	0.44	0.72
Basic - Discontinued Operations (Note 20)	—	0.02	0.01	0.01	0.01	0.01	0.01	0.01
Basic - Earnings Available to FirstEnergy Corp.	0.34	0.52	(0.39)	0.47	(0.35)	1.02	0.45	0.73
Diluted - Continuing Operations	0.34	0.50	(0.40)	0.46	(0.36)	1.00	0.44	0.72
Diluted - Discontinued Operations (Note 20)	—	0.02	0.01	0.01	0.01	0.01	0.01	0.01
Diluted - Earnings Available to FirstEnergy Corp.	0.34	0.52	(0.39)	0.47	(0.35)	1.01	0.45	0.73

FES

CONSOLIDATED STATEMENTS OF INCOME

(In millions)	2013				2012			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Revenues	$ 1,518	$ 1,679	$ 1,452	$ 1,524	$ 1,383	$ 1,550	$ 1,450	$ 1,511
Other operating expense	382	339	387	379	328	342	392	294
Pensions and OPEB mark-to-market	(81)	—	—	—	166	—	—	—
Provision for depreciation	75	80	76	75	72	70	68	62
Operating Income (Loss)	121	65	(39)	95	(56)	167	9	219
Income (loss) from continuing operations before income taxes	114	56	(117)	(1)	(74)	161	(6)	195
Income taxes (benefits)	25	23	(42)	—	(36)	65	(1)	75
Income (loss) from continuing operations	89	33	(75)	(1)	(38)	96	(5)	120
Discontinued operations (net of income taxes)	—	7	4	3	3	5	4	2
Net Income (Loss)	89	40	(71)	2	(35)	101	(1)	122

Executive Officers as of February 24, 2014

Name	Age	Positions Held During Past Five Years	Dates
A. J. Alexander	62	President and Chief Executive Officer (A)(B)	*-present
		Chief Executive Officer (F)	*-present
		President and Chief Executive Officer (G)	2011-present
L. M. Cavalier	62	Senior Vice President, Human Resources (B)	*-present
		Senior Vice President, Human Resources (G)	2011-present
M. J. Dowling	49	Senior Vice President, External Affairs (B)(G)	2011-present
		Vice President, External Affairs (B)	2010-2011
		Vice President, Communications (B)	* - 2010
B. L. Gaines	60	Senior Vice President, Corporate Services and Chief Information Officer (B)(G)	2012-present
		Vice President, Corporate Services and Chief Information Officer (B)(G)	2011-2012
		Vice President, Shared Services, Administration and Chief Information Officer (B)	2009-2011
		Vice President, Information Technology and Corporate Security and Chief Information Officer (B)	*-2009
C. E. Jones	58	Executive Vice President & President, FirstEnergy Utilities (A)(B)(G)	2014-present
		Senior Vice President & President, FirstEnergy Utilities (G)	2011-2013
		Senior Vice President & President, FirstEnergy Utilities (B)	2010-2013
		President (I)(J)	2011-present
		President (C)(D)	2010-present
		Senior Vice President & President, FirstEnergy Utilities (A)	2010-2011
		Senior Vice President, Energy Delivery & Customer Service (B)	2009-2010
		Senior Vice President (C)(D)	2009-2010
		President (E)	*-2009
J. H. Lash	63	President, FE Generation (B)(G)	2011-present
		President (H)(K)	2011-present
		Chief Nuclear Officer (F)	2011-2012
		President and Chief Nuclear Officer (F)	2010-2011
		President, FirstEnergy Nuclear Operating Company (B)	2010-2011
		Senior Vice President and Chief Operating Officer (F)	*-2010
J. F. Pearson	59	Senior Vice President and Chief Financial Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(K)	2013-present
		Senior Vice President and Treasurer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(K)	2012
		Vice President and Treasurer (A)(B)(C)(D)(E)(F)(K)	*-2012
		Vice President and Treasurer (G)(H)(I)(J)	2011-2012
D. R. Schneider	52	President (E)	2009-present
		Senior Vice President, Energy Delivery & Customer Service (B)	*-2009
		Senior Vice President (C)(D)	*-2009
K. J. Taylor	40	Vice President, Controller and Chief Accounting Officer (A)(B)(G)	2013-present
		Vice President and Controller (C)(D)(E)(F)(H)(I)(J)(K)	2013-present
		Vice President and Assistant Controller (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(K)	2012-2013
		Assistant Controller (A)(B)(C)(D)	2010-2012
		Assistant Controller (G)(I)(J)	2011-2012
		Assistant Controller (E)(F)(H)(K)	2012
		Manager, Financial Reporting & Technical Accounting (B)	2009-2010
L. L. Vespoli	54	Executive Vice President, Markets & Chief Legal Officer (A)(B)(C)(D)(E)(F)(G)(H)(I)(J)(K)	2014-present
		Executive Vice President and General Counsel (A)(B)(C)(D)(E)(F)(K)	*-2013
		Executive Vice President and General Counsel (G)(H)(I)(J)	2011-2013

* Indicates position held at least since January 1, 2009

(A) Denotes executive officer of FE
(B) Denotes executive officer of FESC
(C) Denotes executive officer of OE, CEI and TE
(D) Denotes executive officer of ME, PN and Penn
(E) Denotes executive officer of FES
(F) Denotes executive officer of FENOC
(G) Denotes executive officer of AESC
(H) Denotes executive officer of AGC
(I) Denotes executive officer of MP, PE and WP
(J) Denotes executive officer of TrAIL
(K) Denotes executive officer of FE Generation

SHAREHOLDER SERVICES

TRANSFER AGENT AND REGISTRAR

American Stock Transfer & Trust Company, LLC (AST), acts as the Transfer Agent and Registrar. Shareholders wanting to transfer stock, or who need assistance or information, can send their stock certificate(s) or write to FirstEnergy Corp., c/o American Stock Transfer & Trust Company, LLC, P.O. Box 2016, New York, NY 10272-2016. Shareholders also can call toll-free at 1-800-736-3402, between 8:00 a.m. and 8:00 p.m. Eastern time, Monday through Friday. For Internet access to general shareholder and account information, visit the AST website at www.amstock.com/company/firstenergy.asp.

STOCK INVESTMENT PLAN

Registered shareholders and employees of the company can participate in the Stock Investment Plan. To learn more about the company's Stock Investment Plan, visit AST's website at www.amstock.com/company/firstenergy.asp or contact AST toll-free at 1-800-736-3402.

DIRECT DIVIDEND DEPOSIT

Shareholders can have their dividend payments automatically deposited to checking, savings or credit union accounts at any financial institution that accepts electronic direct deposits. Using this free service ensures that payments will be available to you on the payment date, eliminating the possibility of mail delay or lost checks. Contact AST toll-free at 1-800-736-3402 to receive a Direct Dividend Deposit Authorization Agreement.

STOCK LISTING AND TRADING

The common stock of FirstEnergy is listed on the New York Stock Exchange under the symbol FE.

FORM 10-K ANNUAL REPORT

The Annual Report on Form 10-K, as filed with the Securities and Exchange Commission, including the financial statements and financial statement schedules, will be sent to you without charge upon written request to Rhonda S. Ferguson, Vice President and Corporate Secretary, FirstEnergy Corp., 76 South Main Street, Akron, Ohio 44308-1890. You also can view the Form 10-K by visiting the company's website at www.firstenergycorp.com/financialreports.

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METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-F-2:

"Supply projected capital requirements and sources of the filing utility, its parent and system – consolidated - for the test year and each of 3 comparable future years."

RESPONSE:

See ME Exhibit SRS-18 Attachment A for the test year.
The information is not available at this time for the 3 comparable future years.

Metropolitan Edison Company
Source and Application of Funds
(in millions)

	Forecast (TME) 4/30/2016
Application of Funds	
Construction	134
LT/ST Debt Interest	44
Maturities of Bonds & other Long Term Debt	0
Pension Contribution	0
Other	0
Total Applications	**178**
Sources of Funds	
Internal	
Depreciation & Amortization	102
Deferred Income Taxes	6
Dividend payments	(44)
Working Capital & Other	106
Total Internal Sources	169
External	
Bonds & other Long Term Debt	0
Short-term Debt/(Temp Investm	9
Total External Sources	9
Total Sources	**178**

*Forecast beyond 2016 is unavailable

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-F-3:

> "State what coverage requirements or capital structure ratios are required in the most restrictive of applicable indentures/charter tests and how these measures have been computed."

RESPONSE:

a.) Senior Note Indenture dated July 1, 1999

There are no coverage or capital structure ratio requirements in Metropolitan Edison's Senior Note Indenture. The Indenture does contain limitation on liens and limitations on sale leaseback transactions which are defined in the Indenture

b.) Amended and Restated Articles of Incorporation

The Board of Directors may adopt an amendment to these Articles of Incorporation determining, in whole or in part, the express terms, within the limits set forth in these Articles of Incorporation or the Pennsylvania Business Corporation Law, of any class of shares before the issuance of any shares of that class, or of one or more series within a class before the issuance of shares of that series; including, without limitation, division of shares into classes or into series within any class or classes, determination of the designation and the number of shares of any class or series, and the determination of the relative voting rights, preferences, limitations, rights to dividends, conversion rights, redemption rights, stated value, and other special rights of the shares of any class or series.

No Preferred Stock is currently outstanding.

c.) Credit Agreement, dated June 11, 2011, as amended on May 8, 2012, May 8, 2013, October 31, 2013 and March 31, 2014 among FirstEnergy Corp., The Cleveland Electric Illuminating Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, Jersey Central Power & Light Company, Monongahela Power Company, Pennsylvania Electric Company, The Potomac Edison Company and West Penn Power Company as borrowers.

Metropolitan Edison is a borrower under the Credit Agreement and must maintain a Debt to Capitalization Ratio of no more than 0.65 to 1.00 (determined as of the last day of each fiscal quarter). The calculation is defined in the Credit Agreement. The relevant definition are shown in Attachment A.

"***Debt to Capitalization Ratio***" means, for any Borrower, the ratio of Consolidated Debt of such Borrower to Total Capitalization of such Borrower.

"***Consolidated Debt***" means, with respect to any Borrower at any date of determination the aggregate Indebtedness of such Borrower and its Consolidated Subsidiaries determined on a consolidated basis in accordance with GAAP, but shall not include (i) Nonrecourse Indebtedness of such Borrower and any of its Subsidiaries, (ii) obligations under leases that shall have been or should be, in accordance with GAAP, recorded as operating leases in respect of which such Borrower or any of its Consolidated Subsidiaries is liable as a lessee, (iii) the aggregate principal and/or face amount of Attributable Securitization Obligations of such Borrower and its Consolidated Subsidiaries and (iv) the aggregate principal amount of Trust Preferred Securities and Junior Subordinated Deferred Interest Obligations not exceeding 15% of the Total Capitalization of such Borrower and its Consolidated Subsidiaries (determined, for purposes of such calculation, without regard to the amount of Trust Preferred Securities and Junior Subordinated Deferred Interest Debt Obligations outstanding of such Borrower); *provided* that the amount of any mandatory principal amortization or defeasance of Trust Preferred Securities or Junior Subordinated Deferred Interest Debt Obligations prior to the Termination Date shall be included in this definition of Consolidated Debt.

"***Indebtedness***" of any Person means at any date, without duplication, (i) all obligations of such Person for borrowed money, or with respect to deposits or advances of any kind, or for the deferred purchase price of property or services other than trade accounts payable, (ii) all obligations of such Person evidenced by bonds, debentures, notes or similar instruments, (iii) all obligations of such Person upon which interest charges are customarily paid, (iv) all obligations under leases that shall have been or should be, in accordance with GAAP, recorded as capital leases in respect of which such Person is liable as lessee, (v) withdrawal liability incurred under ERISA by such Person or any of its affiliates to any Multiemployer Plan, (vi) reimbursement obligations of such Person (whether contingent or otherwise) in respect of letters of credit, bankers acceptances, surety or other bonds and similar instruments, (vii) all Indebtedness of others secured by a Lien on any asset of such Person, whether or not such Indebtedness is assumed by such Person and (viii) obligations of such Person under direct or indirect guaranties in respect of, and obligations (contingent or otherwise) to purchase or otherwise acquire, or otherwise to assure a creditor against loss in respect of, indebtedness or obligations of others of the kinds referred to above.

"***Nonrecourse Indebtedness***" means, with respect to any Borrower and its Subsidiaries, (i) any Indebtedness that finances the acquisition, development, construction or improvement of an asset in respect of which the Person to which such Indebtedness is owed has no recourse whatsoever to such Borrower or any of its

Affiliates and (ii) any Indebtedness existing on the date of this Agreement that finances the ownership or operation of an asset in respect of which the Person to which such Indebtedness is owed has no recourse whatsoever to such Borrower or any of its Affiliates, in each case of clauses (i) and (ii), other than:

(A) recourse to the named obligor with respect to such Indebtedness (the "***Debtor***") for amounts limited to the cash flow or net cash flow (other than historic cash flow) from the asset; and

(B) recourse to the Debtor for the purpose only of enabling amounts to be claimed in respect of such Indebtedness in an enforcement of any security interest or lien given by the Debtor over the asset or the income, cash flow or other proceeds deriving from the asset (or given by any shareholder or the like in the Debtor over its shares or like interest in the capital of the Debtor) to secure the Indebtedness, but only if the extent of the recourse to the Debtor is limited solely to the amount of any recoveries made on any such enforcement; and

(C) recourse to the Debtor generally or indirectly to any Affiliate of the Debtor, under any form of assurance, undertaking or support, which recourse is limited to a claim for damages (other than liquidated damages and damages required to be calculated in a specified way) for a breach of an obligation (other than a payment obligation or an obligation to comply or to procure compliance by another with any financial ratios or other tests of financial condition) by the Person against which such recourse is available.

"***Total Capitalization***" means, with respect to any Borrower at any date of determination the sum, without duplication, of (i) Consolidated Debt of such Borrower, (ii) the capital stock (but excluding treasury stock and capital stock subscribed and unissued) and other equity accounts (including retained earnings and paid in capital but excluding accumulated other comprehensive income and loss) of such Borrower and its Consolidated Subsidiaries, (iii) consolidated equity of the preference stockholders of such Borrower and its Consolidated Subsidiaries, and (iv) the aggregate principal amount of Trust Preferred Securities and Junior Subordinated Deferred Interest Debt Obligations of such Borrower and its Consolidated Subsidiaries; *provided*, *however*, that, commencing with the fiscal quarter ended September 30, 2013 and for each fiscal quarter ending thereafter, '***Total Capitalization***' shall be determined subject to the following adjustments:

(A) as applicable, for the respective Borrowers, there shall be excluded in such determination the following after-tax effects resulting from non-cash write-downs and non-cash charges occurring and recognized for the periods indicated below as reflected in the consolidated financial statements of the applicable Borrowers for such periods:

(1) in respect of pension and other postemployment benefits occurring and recognized in fiscal years 2011 and 2012, which shall not exceed in the aggregate $691,600,000 for all Borrowers (without duplication but allowing for, as applicable, consolidation);

(2) in respect of asset impairments attributable to the Albright, Rivesville and Willow Island Plants owned by MP, the Armstrong and R. Paul Plants owned by AESC, and the Bay Shore (Units 2-4 only), Eastlake (Units 4-5 only), Fremont and Richland Plants owned by FirstEnergy Generation, LLC occurring and recognized in fiscal year 2011, which shall not exceed in the aggregate $255,400,000 for all Borrowers (without duplication but allowing for, as applicable, consolidation); and

(3) in respect of asset impairments attributable to the Hatfield's Ferry Power Station and the Mitchell Power Station owned by AESC occurring and recognized in fiscal year 2013 through September 30, 2013, which shall not exceed in the aggregate $317,300,000 for all Borrowers (without duplication but allowing for, as applicable, consolidation); and

(B) in addition to the adjustments described in clause (A) above, for the respective Borrowers there shall be excluded in such determination the after-tax effects resulting from non-cash write-downs and non-cash charges attributable or relating to the following: (1)(i) pension and other postemployment benefits, (ii) impairment of regulatory and other long-lived assets, (iii) disallowance of regulatory assets, and (iv) goodwill impairment, in each case, occurring and recognized during the fiscal quarter ending December 31, 2013 and in any fiscal quarter ending thereafter as reflected in the consolidated financial statements of the respective Borrowers for such periods, and (2) disallowance of regulatory assets consisting of marginal transmission line losses of Met-Ed and Penelec occurring during the period from January 11, 2007 through December 31, 2010 as described in the PPUC Order, in each case, occurring and recognized during the fiscal quarter ended September 30, 2013 as reflected in the consolidated financial statements of the respective Borrowers for such period, but such adjustments shall not exceed in the aggregate $1,500,000,000 for all Borrowers (without duplication but allowing for, as applicable, consolidation).

"***Trust Preferred Securities***" means any securities, however denominated, (i) issued by any Borrower or any Consolidated Subsidiary of any Borrower, (ii) that are not subject to mandatory redemption or the underlying securities, if any, of which are not subject to mandatory redemption, (iii) that are perpetual or mature no less than 30 years from the date of issuance, (iv) the indebtedness issued in connection with which, including any guaranty, is subordinate in right of payment to the unsecured and unsubordinated indebtedness of the issuer of such indebtedness or guaranty, and

(v) the terms of which permit the deferral of the payment of interest or distributions thereon to a date occurring after the Termination Date.

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-F-4:

"A schedule of comparative financial data shall be supplied for the test year, the most immediately available annual historical period, prior to the test year, and the 2 calendar years most immediately preceding the test year. Changes in Moody's/S&P ratings, noted on this schedule, shall be accompanied by the Moody's/S&P write up of such change, if available. The following financial data and ratios shall be supplied for the utility's parent, where applicable, if not available for the utility.

a. Times interest earned ratio – pre-tax and post-tax basis
b. Preferred stock dividend coverage ratio—post-tax basis.
c. Times fixed charges earned ratio—pre-tax basis.
d. Earnings per share.
e. Dividend per share.
f. Average dividend yield (52-week high/low common stock price).
g. Average book value per share.
h. Average market price per share.
i. Market price-book value ratio.
j. Earnings-book value ratio (per share basis, average book value).
k. Dividend payout ratio.
l. AFUDC as a % of earnings available for common equity.
m. Construction work in progress as a % of net utility plant.
n. Effective income tax rate.
o. Internal cash generations as a % of total capital requirements."

RESPONSE:

See ME Exhibit SRS-20 Attachment A and ME Exhibit SRS-20 Attachment B

Metropolitan Edison / FirstEnergy Corporation
Comparative Financial Data

	Times Interest Earned Ratio X	Preferred Stock Coverage Post-tax[3] X	Fixed Charges Earned X	Basic Earnings Per Share $	Dividends Per Share $	Average Dividend Yield %	Average Book Value $	Average Market Price $	Market To Book %	Earnings To Book %	Dividend Payout %	AFUDC as % of Earnings %	CWIP as % of Net Utility Plant %	Effective Income Tax Rate %	Internal Cash % of Total Cap. Rqts. %
Actual															
3/31/2013 - MET-ED	2.78		2.73									0.6%	3.6%	48.3%	212%
3/31/201 4 - MET-ED	0.14		0.18									-2.9%	1.4%	49.5%	112%
2013 Annual - FE				$0.94	$ 2.20	7.24%	$ 30.32	$ 30.37	100%	3.09%	234%				92%
Forecast															
3/31/2015 -MET-ED	3.78		3.63									4.1%	2.2%	40.9%	133%
4/30/2016 -MET-ED	2.88		2.79									3.8%	3.8%	43.4%	131%
2014 Annual - FE				$2.50 [1]	$ 1.44	4.63%	$ 30.03	$ 31.13 [2]	104%	8.33%	58%				90%

[1] Calculated as the midpoint of the 2014 non-GAAP EPS guidance of $2.40 to $2.60

[2] Based on a 90-day adjusted close average as of March 31,2014

[3] FE Corp. and Met-Ed do not have Preferred Stock Dividend Requirements

On July 15, 2014, Moody's made the following ratings actions on PA utilities:

- Upgraded Met-Ed's senior unsecured and issuer rating to Baa1 from Baa2.
- Upgraded Penn Power's issuer rating to Baa1 from Baa2; senior secured to A2 from A3.
- Upgraded West Penn Power's issuer rating to Baa1 from Baa2; senior secured to A2 from A3.
- Affirmed Penelec's Baa2 senior unsecured and issuer rating

Other than the changes above, no ratings changes have been made at the Pennsylvania utilities since 2011 other than removal of certain ratings that were no longer applicable due to:

- Met-Ed's senior secured rating was removed in 2011 after its $13.69M FMB was redeemed in April 2011.
- Penelec's senior secured rating was removed after its' FMB indenture was terminated in December 2010.
- West Penn's senior unsecured rating was removed in April 2012 after maturity of an $80M medium term note.

Moody's Investor Services		7/16/2014	12/31/2013	12/31/2012	12/31/2011	12/31/2010
Metropolitan Edison	Issuer Rating	Baa1	Baa2	Baa2	Baa2	Baa2
	Senior Secured	-	-	-	A3	A3
	Senior Unsecured	Baa1	Baa2	Baa2	Baa2	Baa2
	Outlook	stable	stable	stable	stable	stable
Pennsylvania Electric Co.	Issuer Rating	Baa2	Baa2	Baa2	Baa2	Baa2
	Senior Secured	-	-	-	A3	A3
	Senior Unsecured	Baa2	Baa2	Baa2	Baa2	Baa2
	Outlook	stable	stable	stable	stable	stable
Pennsylvania Power Co.	Issuer Rating	Baa1	Baa2	Baa2	Baa2	Baa2
	Senior Secured	A2	A3	A3	A3	A3
	Senior Unsecured	-	-	-	-	-
	Outlook	stable	stable	stable	stable	stable
West Penn Power Co.	Issuer Rating	Baa1	Baa2	Baa2	Baa2	Baa2
	Senior Secured	A2	A3	A3	A3	A3
	Senior Unsecured	-	-	-	Baa2	Baa2
	Outlook	stable	stable	stable	stable	stable

Standard & Poor's		7/16/2014	12/31/2013	12/31/2012	12/31/2011	12/31/2010
Metropolitan Edison	Issuer Rating	BBB-	BBB-	BBB-	BBB-	BBB-
	Senior Secured	-	-	-	BBB	BBB
	Senior Unsecured	BBB-	BBB-	BBB-	BBB-	BBB-
	Outlook	stable	stable	stable	stable	stable
Pennsylvania Electric Co.	Issuer Rating	BBB-	BBB-	BBB-	BBB-	BBB-
	Senior Secured	-	-	-	BBB	-
	Senior Unsecured	BBB-	BBB-	BBB-	BBB-	BBB-
	Outlook	stable	stable	stable	stable	stable
Pennsylvania Power Co.	Issuer Rating	BBB-	BBB-	BBB-	BBB-	BBB-
	Senior Secured	BBB+	BBB+	BBB+	BBB+	BBB+
	Senior Unsecured	-	-	-	-	-
	Outlook	stable	stable	stable	stable	stable

West Penn Power Co.	Issuer Rating	BBB-	BBB-	BBB-	BBB-	BBB-
	Senior Secured	BBB+	BBB+	BBB+	BBB+	BBB+
	Senior Unsecured	-	-	-	BBB-	BBB-
	Outlook	stable	stable	stable	stable	stable

METROPOLITAN EDISON COMPANY

FILING REQUIREMENT III-D-1:

"Provide a complete support for claimed common equity rate of return."

RESPONSE:

See the testimony and exhibits of Steven R Staub and Dr. Vilbert.

Metropolitan Edison Company
Capitalization & Capitalization Ratios
($000)

	Actuals at March 31, 2014		Forecast at March 31, 2015		Forecast at April 30, 2016	
	Amount Outstanding	Ratios Rate Making	Amount Outstanding	Ratios Rate Making	Amount Outstanding	Ratios Rate Making
Long Term Debt [1]	778,118	48.8%	849,661 [2]	50.4%	849,707 [2]	50.0%
Preferred Stock	0	0.0%	0	0.0%	0	0.0%
Common Equity	817,892	51.2%	834,704	49.6%	848,489	50.0%
Total Capital	1,596,010	100.0%	1,684,365	100.0%	1,698,196	100.0%

Notes:

[1] Includes current portion of long-term debt

[2] Reflects changes in long-term debt of:

New long-term debt issues	250,000	Issued in June 2014	0
Long-term debt paydown	(178,500)		0
Unamort discount on long-term debt	43		46

Met-Ed

Schedule of Long Term Debt Outstanding Projected at 4/30/2016

Title	Date of Offering	Date of Maturity	Principal Amount Issued	Amount Outstanding	Amount Retired	Amount Reacquired	Gain (Loss) on Reacquisition	Interest Rate	Prem / (Disc) & (Issuance) Expenses	Net Proceeds	Annual / Sinking Fund	Effective Rate	Total Average Weighted Effective Cost Rate
Senior Unsecured Notes													
4.000% Senior Notes	6/11/2014	4/15/2025	250,000,000	250,000,000				4.0000%	(2,874,442)	247,125,558		4.1321%	
3.50% Senior Notes	3/15/2013	3/15/2023	300,000,000	300,000,000				3.5000%	(426,000)	299,574,000		3.5170%	
7.70% Senior Notes	1/20/2009	1/15/2019	300,000,000	300,000,000				7.7000%	(1,950,000)	298,050,000		7.7950%	
			850,000,000	**850,000,000**	-				**(5,250,442)**	**844,749,558**			**5.2078%**

Met-Ed
Capital Cost Rates
4/30/2016

	($000)	Ratios	Cost Rate	Weighted Average Cost of Capital
Common Equity	848,489	49.96%	10.9%	5.44%
Preferred Stock	-			
Long-term Debt	849,707	50.04%	5.2078%	2.61%
Total Capitalization	1,698,196	100.00%		8.05%

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2014-2428745

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. R-2014-2428743

PENNSYLVANIA POWER COMPANY
DOCKET NO. R-2014-2428744

WEST PENN POWER COMPANY
DOCKET NO. R-2014-2428742

Direct Testimony
of
Hillary E. Stewart

List of Topics Addressed

Cost of Service Studies
Jurisdictional Separation Studies

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DIRECT TESTIMONY
OF
HILLARY E. STEWART

I. INTRODUCTION, QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q. Please state your name and business address.

A. My name is Hillary E. Stewart. My business address is 76 South Main Street, Akron, Ohio 44308.

Q. By whom are you employed and in what capacity?

A. I am a Rates Analyst in the Rates and Regulatory Affairs Department of FirstEnergy Service Company.

Q. What are your duties as a Rates Analyst?

A. My direct responsibilities involve analyzing customer behavior by performing various studies and surveys and, as part of this overall role, developing Cost of Service Studies ("COSSs") for submission in utility regulatory proceedings.

Q. What is your educational and professional background?

A. My educational and professional background is described in Appendix A of this testimony.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Metropolitan Edison Company (Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power"), and West Penn Power Company ("West Penn") (collectively, the

"Companies") for whom I prepared, and am sponsoring, COSSs for the fully projected future test year ending April 30, 2016. My testimony and accompanying COSSs are being submitted in support of the Companies' filings with the Pennsylvania Public Utility Commission ("Commission") to increase their distribution base rates.

Q. What is the purpose of your testimony in this proceeding?

A. I will explain the cost of service principles underlying the COSSs that I performed, the methods and procedures employed to perform those studies and the results those studies produced. To assure a common understanding of technical terms germane to the COSSs, I have provided a glossary of commonly used terms as Appendix C to my testimony. Terms defined in the glossary are denoted in the testimony with an asterisk (*). I will also provide the results of a jurisdictional separation study that was prepared under my supervision.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring Exhibits HES-1 and HES-2 for each of the Companies, which consist of the following:

Exhibits HES – 1 contain the COSS for each Company using the Non-coincident Peak Demand* allocation method. These studies were performed using the revenue requirements for the fully projected future test year and revenues at both existing and proposed revenues. They also provide details of the Federal Energy Regulatory Commission's ("FERC")

Uniform System of Accounts that were employed to record, by account, the components of revenue requirement that formed the basis for the studies.

Exhibits HES – 2 contain the supporting studies for functionalizing costs and developing allocation factors used in the COSSs. An explanation of the supporting studies is contained within Exhibits HES-2, and I provide an overview of those studies later in my testimony.

II. GENERAL DESCRIPTION OF COSS PROCESS

Q. Describe briefly the steps employed in performing a COSS.

A. Typically, a COSS follows the three basic steps prescribed in the *Electric Utility Cost Allocation Manual* published by the National Association of Regulatory Commissioners ("NARUC") for arranging accounting data into a format that facilitates assigning the total cost of service to individual rate schedules or service classifications within an electric utility's rate structure. These steps consist of the following:

1. **Functionalization** is the process of identifying the functions (e.g., generation, transmission, distribution) associated with a company's assets used, and expenses incurred, to furnish utility service in order to determine the particular rate schedules that should share responsibility for each of those assets and expenses. Within the distribution function, it may be

necessary to separate costs into sub-functions, as I explain later in my testimony.

2. **Classification** is the process of classifying costs as customer-related, demand-related, or energy-related in order to facilitate assigning such costs to rate schedules in accordance with identifiable characteristics. The way costs are classified will determine the manner in which they should be allocated to the rate schedules. Some facilities may serve more than one classification and, if so, the costs recorded in those accounts are divided between classifications accordingly.

3. **Allocation** is the process of assigning costs to rate schedules based upon measurable characteristics. For example, customer costs generally vary on the basis of the number of customers (or customer accounts) and, therefore, are allocated based on the number of customers (or customer accounts). In some cases, costs can be traced in company records in sufficient detail to directly assign them to a particular rate schedule. Street lighting fixtures are an example of a cost that can be directly assigned.

Q. Please describe the software you used in performing the Companies' COSSs.

A. The COSSs were prepared using a model developed internally by FirstEnergy Service Company employing Microsoft Excel as the underlying platform for manipulating the cost of service data and reporting the results of the COSSs.

Q. How are the results of the COSSs intended to be used in developing proposed rates?

A. As explained by Kevin M. Siedt in Met-Ed/Penelec/Penn Power/West Penn Statement No. 4, the COSS provides the starting point for the development of the Companies' Rate Design.* A COSS allocates a company's total cost of service to each of its rate schedules. The cost of service for each rate schedule is compared to the revenues produced, or projected to be produced, under existing rates. For purposes of my COSSs, pro forma revenues for the fully projected future test year were furnished by Mr. Siedt. From these inputs, the earnings level, typically expressed in the form of a class rate of return or Unitized Return,* is calculated for each rate schedule. These data indicate, based on a snapshot at a single point in time, whether a particular rate schedule is providing revenue that is less than, equal to, or more than the cost to furnish service to customers on that rate schedule.

As Mr. Siedt explains, the rate designer uses the results of the COSS along with various other factors and the exercise of professional judgment to determine the portion of the total revenue increase assigned to each rate schedule. Once the revenue increases, by rate schedule, are determined, the COSS is used to calculate the resulting rates of return, by rate schedule, under proposed rates. Comparing the results of the COSS under existing and proposed rates provides an indication of whether, and to what extent, the proposed increases move each rate schedule closer to its cost of service. Also, because the COSS provides a breakdown of costs by classification (e.g., customer-related or demand-related) for each rate

schedule, the results of the COSS are used to identify the level of costs that should be recovered in each component of a rate (e.g., customer charge or demand charge).

Q. What allocation method was used in the COSSs to allocate demand-related costs among rate schedules?

A. The Non-coincident Peak Demand* allocation method was used to allocate costs classified as demand-related. As its name implies, this method allocates demand costs among rate schedules in proportion to their Non-coincident Peak Demands. As employed by the Companies, this method allocates demand costs for certain large distribution plant accounts based on the Non-coincident Peak Demands of three groups of customers served by the Companies.

The first group, identified as "PRI" in the COSS, consists of customers that receive service at primary voltage and, therefore, use only the Primary Distribution* system. The second group, identified as "SEC" in the COSS, consists of those customers that receive service at secondary voltage but use both Primary Distribution* and Secondary Distribution* plant assets to obtain that service. The third group, identified as "PRI_SEC" in the COSS, consists of all customers using the distribution system or, in other words, the aggregate of the PRI and SEC groups. The manner in which these groupings are used to allocate sub-functionalized costs is discussed later in my testimony.

Q. Have you prepared a diagram that illustrates how customers in each of the three groups discussed above and the facilities serving them were identified?

A. Yes. Appendix B to my testimony is a realistic representation of a portion of a distribution system showing how primary and secondary facilities are used to serve each of the three groups of customers. As Appendix B shows: (1) portions of the Primary Distribution system serve only primary voltage customers; (2) portions of the Primary Distribution system serve both primary and secondary voltage customers; and (3) portions of the Primary Distribution system are used only to deliver power to the Secondary Distribution system and, therefore, serve only secondary voltage customers. Appendix B also shows that the Secondary Distribution system serves only secondary voltage customers.

III. DETAILED DESCRIPTION OF THE COSS PRESENTED IN THIS CASE

Q. Please describe Exhibits HES-1.

A. Exhibits HES-1 are divided into two sections, as follows:

Section 1 contains the COSS based on revenues at existing rates. Page 1 shows the calculation of each rate schedule's rate of return. The remainder of Section 1 shows in detail how each FERC account associated with the line items on page 1 was functionalized and how each functionalized cost was allocated among rate schedules.

Section 2 shows the results of the COSS based on revenues at proposed rates, as well at the revenues required for each rate schedule to produce a rate of return

equal to the applicable Company's claimed overall rate of return. Page 1 shows the calculation of each rate schedule's rate of return at proposed rates, and page 2 shows the calculation at rates of return equal to the applicable Company's claimed overall rate of return. Associated income taxes are also shown on each page.

Q. Please describe each Companies' Exhibit HES-2.

A. Exhibits HES-2 contain the supporting studies used to develop the COSS. A brief description of each supporting study is provided below. A more detailed description of each supporting schedule is provided in Exhibits HES-2.

Study No.	Title	Description
1	Demand Allocators	This study develops the allocation factors for distribution plant.
2	Plant Functionalization (Accounts 301-303, 389-398)	This study shows how General Plant was functionalized.
3	Customer Deposits Allocation	This study allocates among rate schedules customer deposits, which are treated as a rate base deduction in developing revenue requirement.
4	Customer Account and Information Expenses Allocation	This study allocates expenses in the applicable accounts to rate schedules based on straight or weighted customer counts.
5	Labor (O&M)	This study identifies the labor component of operation and maintenance expenses by FERC account.
6	Meter Plant Allocation (Account 370)	This study allocates the cost of metering equipment to rate schedules.
7	Minimum Grid and Primary/Secondary Studies	Two studies are set forth in this portion of Exhibit HES-2. The minimum grid study determines the cost of minimum-sized distribution facilities recorded in FERC Plant Accounts* 364-368. The primary/secondary study shows how the cost of distribution assets recorded in

		FERC Plant Accounts 364-367 was divided into two parts corresponding to: (1) the cost of distribution plant used to furnish service to customers that use only Primary Distribution facilities; and (2) the cost distribution plant used to furnish service to customers that use both Primary Distribution and Secondary Distribution facilities.
8	Street Lighting Study	This study allocates the costs recorded in FERC Plant Accounts 364 (distribution poles) to street lighting customers.
9	Allocation of Other Revenue	This study functionalizes Other Revenues.
10	Line Losses	This study shows the line losses that are stated in each Company's Supplier Tariff.

Q. Please describe the function(s) included in the COSSs.

A. Following the restructuring of the electric industry in Pennsylvania, the Companies ceased to own or operate generating facilities used to provide jurisdictional retail service in the state. Additionally, the transmission facilities of Met-Ed, Penelec and West Penn (Penn Power has no FERC jurisdictional transmission facilities) are subject to FERC jurisdiction and are under the operational control of PJM Interconnection LLC, which is the FERC-approved regional transmission organization for each Company's control area. Accordingly, the generation and transmission functions are excluded from the Pennsylvania jurisdictional costs that are used to determine the Companies' distribution rates. Therefore, the only function that is relevant for functionalizing costs for distribution service in the COSS is "distribution," which comprises the rate base and operating and maintenance expenses of the Companies' distribution systems, customer premises facilities and customer accounting, billing and information systems. All of the costs functionalized as distribution were derived

from the costs recorded in accounts that the Companies maintain in accordance with the FERC's Uniform System of Accounts.

Q. Was there a need to further divide the distribution function into sub-functions?

A. Yes. The functionalized distribution plant data did not provide adequate detail because customers take service at different voltage levels. Therefore, it was necessary to sub-functionalize distribution plant costs recorded in FERC Plant Accounts 361 – 368 based on voltage peak responsibility to properly allocate such costs among rate schedules. As previously mentioned, Supporting Study No. 7 includes the study conducted to sub-functionalize those accounts. This study sub-divided the plant accounts into amounts to be apportioned between primary service voltage rate schedules included in the PRI and SEC groups. The following table shows how cost responsibility is shared among the three groups I previously identified with respect to each of the aforementioned plant accounts:

ACCOUNT	DESCRIPTION	GROUP
361	Structures	PRI_SEC
362	Station Equipment	PRI_SEC
364P	Poles-Primary	PRI
364S	Poles-Secondary	SEC
364Z	Poles-Streetlight	SEC
365P	Primary Overhead Conductor	PRI
365S	Secondary Overhead Conductor	SEC
366P	Primary Underground Conduit	PRI
366S	Secondary Underground Conduit	SEC

367P	Primary Underground Conductor	PRI
367S	Secondary Underground Conductor	SEC
368	Transformers	SEC

Q. How was the sub-functionalization performed?

A. As more fully explained in Supporting Study No. 7, the sub-functionalization was done by tracing distribution circuits from primary power customers back to the substations that serve them and identifying the portions of the primary distribution facilities that are used by such primary power customers. The remainder of the primary distribution system, which is not used by these customers, serves only secondary voltage load.

Q. Please describe classification, which is the second step in the development of the COSS.

A. The Companies adhered to, and followed, the NARUC Cost Allocation Manual and the cost of service principles set forth therein to classify their distribution assets and operating costs. The NARUC Cost Allocation Manual (pp. 96-98) states that an electric utility's distribution-related facilities are, from a design and operational perspective, sized to meet the maximum kW load (demand) requirements of customers. In addition, the NARUC Cost Allocation Manual (p. 89) states that all distribution costs should be classified as either customer or demand related, or as a combination of those two factors. In accordance with NARUC's recommendations, the Companies sub-functionalized their facilities into primary and secondary voltage level components as discussed previously

and, with respect to distribution mass property accounts (Plant Accounts 364-369), identified the customer and demand-related components.

Q. How were the customer and demand components determined?

A. As the NARUC Cost Allocation Manual also recommends, the customer component was determined by a minimum grid study, which is set forth in Supporting Study No. 7. A minimum grid study identifies the costs of poles, conductors, transformers, and service drops of the minimum size that would be required to serve a customer. The remainder of the costs recorded in each account therefore comprise the demand component. The customer component is allocated to rate schedules based on the number of customer accounts. The demand component is allocated on the basis of Non-coincident Peak Demands.

Q. Please describe the process of allocation, which is the third step in the development of the COSS.

A. Sub-functionalized, classified costs are allocated among rate schedules based upon measurable characteristics. The method used to allocate costs in each account included in the COSSs is shown in Section No. 1 of each Company's Exhibit HES-1 on pages 40-43 for Met-Ed, pages 35-38 for Penelec, pages 42-46 for Penn Power and pages 34-37 for West Penn. In some cases, the allocation factor for a particular account is a factor developed by aggregating the allocation of a group of other accounts, which is referred to as a "pattern group." This is done when the account being allocated exhibits characteristics that are a blend of the various characteristics of each account in the pattern group. In some

instances, allocation is not used because the Companies have recorded costs in sufficient detail to be able to directly assign those costs to one or more rate schedules. This is the case with Plant Account 373, which is directly assigned to street lighting customers because the facilities represented by costs recorded in that account serve street lighting customers exclusively.

Q. Why was the Non-coincident Peak Demand method used to allocate demand-related distribution costs?

A. Load diversity affects system design and, therefore, consistent with cost-causation principles, it also influences how costs are allocated among rate schedules. At the very highest voltage levels of the electric grid – specifically, the bulk transmission portion – individual customer and customer class loads are consolidated within the totality of energy moving on the system. At this level, load is considered to be the most diverse because the peak loads of any individual customer or class are most likely occurring at times that do not coincide with the overall system peak. Moving down the delivery system from bulk transmission to the distribution of electricity to a customer location, load becomes less diverse; that is, the peak for total load on the distribution facilities is much more likely to coincide with customers' peak load. In other words, because distribution facilities serve load that is much more localized than the consolidated loads served at the bulk transmission level, distribution facilities must be sized to meet maximum demands that can be, and often are, imposed on them at any time of the year, not just at the time of the system coincident peak. This characteristic of the distribution system and the loads it carries warrants the use of Non-coincident

Peak Demand to allocate demand-related costs, as the NARUC Cost Allocation Manual (p. 97) expressly provides:

> Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities.

Q. How did the Companies determine Non-coincident Peak Demands?

A. The Load Data* available to the Companies make it possible for them to identify with reasonable accuracy the maximum Non-coincident Peak Demands of each rate schedule.

Q. How were costs allocated for Accounts 360, 369, 370, 371 and 373?

A. Costs recorded in Account 360 – Land and Land Rights were allocated using the distribution plant accounts 361 to 369 as a pattern group. That is, the costs in that account were allocated in proportion to the totality of those other plant costs. Costs recorded in Account 369 – Services were allocated on a customer basis to all secondary customers because each secondary customer has a service. Costs recorded in Account 370 were allocated based on a meter-cost weighting of the number of customers, as explained in more detail in Supporting Study No. 6. Costs recorded in Account 371 and 372 were directly assigned to the area lighting rate schedule. Costs recorded in Account 373 were directly assigned to the street lighting rate schedules, as I previously noted.

Q. Why were Met-Ed Rate Schedule TP (Transmission Power), Penelec Rate Schedule LP (Large Primary Power) and West Penn Rate Schedule PP (Primary Power) 40 assigned primary distribution costs?

A. Customers served under the terms and conditions of these rate schedules can take service at either distribution voltages or transmission voltages. Only the loads of those customers receiving primary distribution service were included in the demand allocation factors for these rate schedules.

Q. How were distribution costs assigned or allocated to Rate Schedules TP, LP, and PP40?

A. Met-Ed Rate Schedule TP was divided into sub-rate schedules TP_P and TP_A. Penelec Rate Schedule LP was divided into sub-rate schedules LP_P and LP_A. Sub-classes TP_P and LP_P formed the basis for allocating distribution plant to customers on Rate Schedules TP and LP that take service at distribution (primary) voltage. Sub-classes TP_A and LP_A formed the basis for allocating expenses and distribution plant used by both primary and transmission customers taking service under Rate Schedules TP or LP. Cost allocated to sub-classes TP_A and LP_A include, for example, Customer Account and Information expenses and Meters and associated expenses. The same approach was used for West Penn Rate Schedule PP40.

Q. Does Penelec provide retail electric service to customers located outside Pennsylvania?

A. Yes, it provides retail electric service to customers located in the Waverly District of New York. Penelec provides service in New York under and subject to the jurisdiction of the New York Public Service Commission.

Q. Were appropriate portions of Penelec's expenses and asset costs allocated to customers in the Waverly District?

A. Yes, they were. Penelec allocated expenses and plant assets to those customers in the same manner it allocated such costs to its customers in the Commonwealth of Pennsylvania. The Penelec COSS includes Waverly District rate schedules in the proper rate schedule groupings to ensure costs are allocated accurately across all customers with similar characteristics. The revenues, expenses, assets and other operating costs associated with Penelec's service to Waverly District customers were eliminated from Penelec's Pennsylvania jurisdictional revenue requirement developed by Richard A. D'Angelo as discussed in Met-Ed/Penelec/Penn Power/West Penn Statement No. 2.

Q. Please summarize the results of the COSS.

A. The rates of return and Unitized Returns for each rate schedule of each of the Companies at existing and proposed rates are summarized in the charts below:

Distribution Rates of Return												
COSS Rates of Return			COSS Rates of Return - Unitized			COSS Rates of Return			COSS Rates of Return - Unitized		
Rate	Existing	Proposed	Rate	Existing	Proposed	Rate	Existing	Proposed	Rate	Existing	Proposed
ME_RS	1.49%	7.67%	ME_RS	0.71	0.95	PP_RS	3.5%	8.2%	PP_RS	0.87	0.96
ME_GSV	11.54%	25.68%	ME_GSV	5.48	3.19	PP_GSR	8.5%	15.6%	PP_GSR	2.13	1.83
ME_GSS	-1.50%	2.97%	ME_GSS	(0.71)	0.37	PP_GSS	0.7%	2.0%	PP_GSS	0.17	0.23
ME_GSM	9.10%	14.53%	ME_GSM	4.33	1.80	PP_GSM	11.1%	16.3%	PP_GSM	2.78	1.92
ME_GSL	3.26%	8.26%	ME_GSL	1.55	1.03	PP_GSL	10.8%	16.2%	PP_GSL	2.72	1.91
ME_GP	-1.07%	5.46%	ME_GP	(0.51)	0.68	PP_GP	-5.3%	-0.6%	PP_GP	(1.32)	(0.07)
ME_TP	-0.01%	4.94%	ME_TP	(0.01)	0.61	PP_OH	6.1%	0.3%	PP_OH	1.54	0.04
ME_BRD	2.85%	8.48%	ME_BRD	1.35	1.05	PP_PNP	6.8%	8.5%	PP_PNP	1.71	1.00
ME_MS	16.32%	30.43%	ME_MS	7.76	3.78	PP_POL	-0.9%	1.3%	PP_POL	(0.24)	0.15
ME_POL	1.86%	5.23%	ME_POL	0.88	0.65	PP_STLT	6.9%	8.7%	PP_STLT	1.74	1.02
ME_STLT	8.55%	9.81%	ME_STLT	4.06	1.22	PP_GT	24.7%	34.7%	PP_GT	6.21	4.08
Meted Total	2.10%	8.05%	Meted Total	1.00	1.00	Penn Power Total	4.0%	8.5%	Penn Power Total	1.00	1.00
PN_RS	3.1%	7.67%	PN_RS	0.77	0.92	WP_RS	3.7%	7.5%	WP_RS	0.77	0.92
PN_GSV	10.8%	18.69%	PN_GSV	2.69	2.25	WP_GS10	12.1%	17.7%	WP_GS10	2.54	2.18
PN_GSS	-1.5%	1.77%	PN_GSS	(0.38)	0.21	WP_GSS	-4.0%	-0.9%	WP_GSS	(0.84)	(0.11)
PN_GSM	13.6%	19.05%	PN_GSM	3.40	2.29	WP_GSM	15.4%	16.7%	WP_GSM	3.22	2.05
PN_GSL	11.9%	12.02%	PN_GSL	2.98	1.45	WP_PP40	-1.4%	4.9%	WP_PP40	(0.29)	0.60
PN_GP	1.0%	4.60%	PN_GP	0.26	0.55	WP_GSL	11.4%	12.0%	WP_GSL	2.38	1.48
PN_LP	5.0%	8.40%	PN_LP	1.24	1.01	WP_POL	20.2%	34.9%	WP_POL	4.24	4.28
PN_BRD	20.7%	24.95%	PN_BRD	5.17	3.00	WP_PSU	6.5%	11.7%	WP_PSU	1.36	1.43
PN_H	15.9%	17.31%	PN_H	3.96	2.08	WP_PP44	-4.2%	1.4%	WP_PP44	(0.87)	0.17
PN_POL	11.3%	15.41%	PN_POL	2.83	1.85	WP_PP46	-0.8%	4.6%	WP_PP46	(0.16)	0.56
PN_STLT	-3.8%	-2.73%	PN_STLT	(0.95)	(0.33)	WP_AGS	21.7%	71.0%	WP_AGS	4.54	8.72
PA JURIS	4.0%	8.31%	PA JURIS	1.00	1.00	WP_STLT	5.0%	0.8%	WP_STLT	1.04	0.09
NY JURIS	5.2%		NY JURIS	1.29		West Penn Total	4.8%	8.1%	West Penn Total	1.00	1.00
Penelec Total	4.0%		Penelec Total	1.00							

IV. FERC JURISDICTIONAL SEPARATION STUDIES

Q. Did you prepare separation studies for the purpose of identifying the portions of the plant in service and labor expenses of each of the Companies that relate to the provision of FERC jurisdictional transmission service?

A. Yes. Under my supervision, Met-Ed, Penelec and West Penn performed detailed analyses of their non-jurisdictional labor expenses and plant in service similar to the analyses performed for purposes of Met-Ed's and Penelec's 2006 base rate cases to identify the portions of each Companies' O&M expenses and plant costs that relate to FERC-jurisdictional service. A separation study is not required for Penn Power because it does not provide FERC jurisdictional transmission service and, therefore, all of its assets and operating costs are associated with Pennsylvania jurisdictional service. For Met-Ed, Penelec and West Penn, the percentage allocations to FERC jurisdictional service are shown below:

	Labor Allocation	Plant Allocation
Met-Ed	10.43%	22.30%
Penelec	4.83%	23.60%
West Penn	9.00%	19.58%

Q. Does this conclude your direct testimony?

A. Yes, it does.

Appendix A

Hillary E. Stewart
Rates Analyst
FirstEnergy Corporation
76 South Main Street
Akron, Ohio 44308
330.252.1499

SUMMARY

I am a rate analyst in Forecasting & Load Evaluation, where I have been responsible for developing and preparing the load and revenue forecast for Meted, Penelec, and Penn Power. Additionally, I have been responsible for several projects related to customer behavior, regulatory financial analysis, load research and forecasting, and energy efficiency.

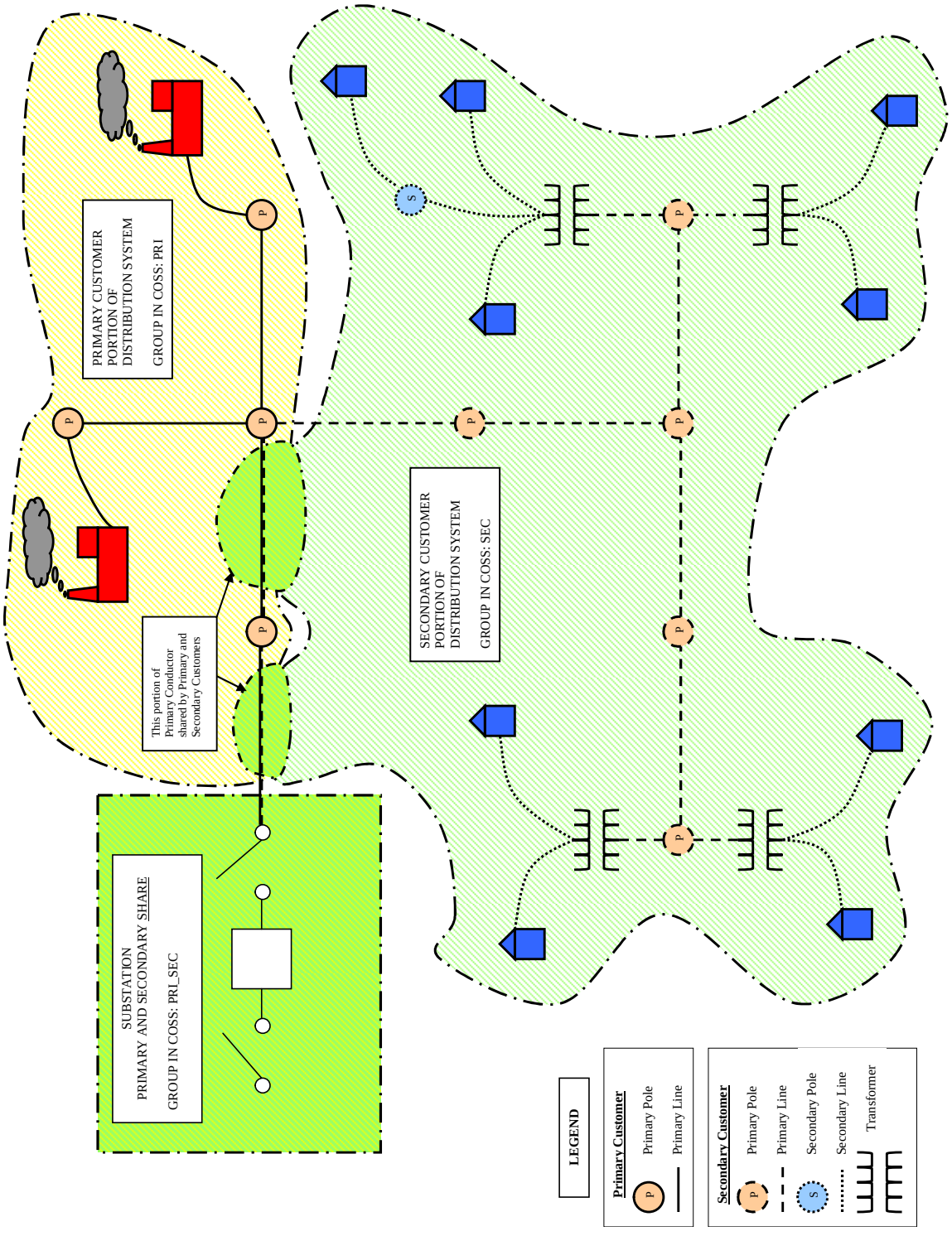
PROFESSIONAL EMPLOYMENT

2008 to Present	**FirstEnergy Service Company** Rates Analyst – Rates and Regulatory Affairs

EDUCATION / CERTIFICATIONS

University of Akron, BS, Applied Mathematics, 2007
University of Akron, MA, Economics, 2008
University of Akron, MS, Statistics, 2014 (Expected)

Appendix B


PRIMARY CUSTOMER
PORTION OF
DISTRIBUTION SYSTEM
GROUP IN COSS: PRI
SECONDARY CUSTOMER
PORTION OF
DISTRIBUTION SYSTEM
GROUP IN COSS: SEC
This portion of
Primary Conductor
shared by Primary and
Secondary Customers
SUBSTATION
PRIMARY AND SECONDARY SHARE
GROUP IN COSS: PRI_SEC
P
S
LEGEND
Primary Customer
Primary Pole
Primary Line
Secondary Customer
Primary Pole
Primary Line
Secondary Pole
Secondary Line
Transformer

Appendix C

Glossary of Terms

Allocation Method – A theoretical basis for apportioning a cost that is incurred to provide service to all customers or a sub-set of customers.

Annual Average Demand – the kWh of a rate schedule or group of rate schedules divided by 8,760 (the number of hours in a year).

Coincident Peak Demand – the demand of a rate schedule at the time of the Company's maximum hourly demand.

Load Data –Typically expressed is Megawatt Hours or Kilowatt Hours, this represents the amount of peak demand or total energy consumption imposed on a utility system by a customer group or rate schedule.

Load Factor - As used in this COSS, load factor is the ratio of the Company's annual average demand divided by the Company's maximum hourly demand.

Non-coincident Peak Demand – the maximum demand of a rate schedule at any time. This demand may or may not be at the time of the coincident peak demand.

Plant Account –A component of the accounting system under which property used to provide utility service is grouped for accounting purposes according to a defined set of common characteristics.

Primary Distribution – The portion of the electric distribution system that consists of conductors, poles, transformers and associated plant that distributes service at voltage levels lower than transmission facilities and higher than secondary distribution facilities.

Rate Design – The development of tariff rates that, when applied to billing determinants, produce a total authorized revenue requirement.

Sales Forecast –A projection of future levels of demand and energy consumption by customers on a Megawatt Hour or Kilowatt Hour basis for a given period of time.

Secondary Distribution – The portion of the electric distribution system that consists of conductors, poles, transformers and associated plant that distributes service at voltage levels lower than Primary Distribution Facilities.

Standard Filing Requirements –The data filed by a public utility pursuant to the Pennsylvania Public Utility Commission regulations specifying the supporting data required in rate change filings.

Appendix C

Glossary of Terms

Unitized Return – The ratio of the individual rate schedule rate of the return to the Company overall rate of return.

Voltage Peak Demand – the maximum hourly demand of a group of rate schedules being served by the voltages specified for the group.

Met-Ed
Exhibit HES – 1
Witness: H. E. Stewart

Cost of Service Study

Met-Ed Exhibit HES – 1
Table of Contents

Met-Ed

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METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - TOTAL SUMMARY
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
PRESENT RATES, $1,000s

	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	BRD	MS	POL	STLT
RATE BASE												
Plant in Service	2,265,855	1,612,628	1,521	111,200	241,923	57,068	177,827	24,250	198	1,837	8,146	29,257
Depreciation Reserve	751,301	530,752	499	36,317	79,845	18,913	61,713	9,006	64	605	4,011	9,575
Net Plant	1,514,554	1,081,875	1,022	74,884	162,077	38,155	116,113	15,244	134	1,232	4,135	19,682
Rate Base Additions	281,079	199,600	190	13,810	30,387	7,198	22,305	3,051	25	231	911	3,370
Rate Base Deductions	382,669	268,196	261	22,261	41,728	9,782	29,989	4,047	32	301	1,324	4,746
Rate Base Other Total	(101,589)	(68,596)	(72)	(8,450)	(11,341)	(2,584)	(7,684)	(996)	(7)	(70)	(413)	(1,376)
Rate Base Total	1,412,965	1,013,279	950	66,434	150,737	35,571	108,429	14,248	126	1,162	3,722	18,306
INCOME STATEMENT												
Revenue												
Tariff Revenue Total	266,346	186,054	344	8,972	43,400	5,985	13,382	2,395	22	479	668	4,644
Other Revenue Total	18,593	14,476	11	1,095	1,385	238	913	131	1	9	30	304
Retail Total	284,939	200,530	356	10,067	44,785	6,223	14,294	2,526	23	488	698	4,948
Expenses												
Total Operation & Maintenance Expense	105,570	82,757	64	5,220	7,556	1,435	6,619	1,017	5	48	134	716
Depreciation Expense	76,168	54,812	58	4,122	7,470	1,607	6,001	920	7	60	277	834
Other Expenses Amortization Expense Total	22,089	15,539	15	1,071	2,431	581	1,804	247	2	19	82	298
Taxes Other than Income Taxes Excl GRT	6,110	4,482	4	317	581	125	441	74	0	4	13	68
Gross Receipts Tax	15,714	10,977	20	529	2,561	353	790	141	1	28	39	274
Total Operating Expense	225,652	168,567	162	11,259	20,598	4,101	15,654	2,399	16	159	545	2,190
Income Before Taxes	59,287	31,962	194	(1,192)	24,187	2,122	(1,360)	127	7	329	153	2,758
Income taxes												
Current State Income Tax	6,318	3,498	20	(86)	2,435	212	(111)	23	1	33	17	277
Current Federal Income Tax	19,923	11,030	62	(270)	7,680	668	(351)	71	2	104	54	873
Provision for Deferred Income Taxes	3,598	2,560	2	177	384	91	282	39	0	3	13	46
Investent Tax Credit Adjustments	(283)	(201)	(0)	(14)	(31)	(7)	(22)	(3)	(0)	(0)	(1)	(4)
Total Income Tax	29,556	16,888	84	(193)	10,469	964	(203)	129	3	139	83	1,193
Net Income After Tax	29,731	15,074	110	(998)	13,718	1,158	(1,157)	(2)	4	190	69	1,565
Rate of Return	2.10%	1.49%	11.54%	-1.50%	9.10%	3.26%	-1.07%	-0.01%	2.85%	16.32%	1.86%	8.55%

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
PLANT IN SERVICE, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
Intangible Plant																
301	Organization	DIST_CUST	84	67	0	6	3	0	6	0	0	0	0	0	0	1
		DIST_DEMAND	40	21	0	1	10	3	3	1	0	1	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	124	88	0	6	13	3	10	1	0	1	0	0	0	2
302	Franchise and Consents	DIST_CUST	112	89	0	7	4	0	8	0	0	0	0	0	0	2
		DIST_DEMAND	53	29	0	1	13	4	4	1	0	1	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	165	118	0	8	18	4	13	2	0	2	0	0	0	2
303	Intangible Plant	DIST_CUST	52,176	44,480	23	2,799	1,805	67	2,496	133	57	76	2	7	66	297
		DIST_DEMAND	9,111	4,563	10	135	2,138	659	1,177	372	0	372	1	18	8	32
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	61,287	49,042	33	2,935	3,943	726	3,673	505	57	448	3	24	74	329
	Int Original Cost Plant	**DIST_CUST**	52,372	44,636	23	2,812	1,813	67	2,511	133	57	77	2	7	67	300
		DIST_DEMAND	9,204	4,613	10	137	2,161	666	1,184	375	0	374	1	18	8	32
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	61,576	49,248	33	2,949	3,974	733	3,695	508	57	451	3	24	75	333
Distribution Plant																
360	P - Land	DIST_CUST	21,494	17,284	9	1,415	844	12	1,637	56	0	56	2	5	37	192
		DIST_DEMAND	10,643	5,655	12	167	2,653	817	962	304	0	304	1	22	10	40
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	32,137	22,940	22	1,582	3,496	830	2,599	360	0	360	3	27	47	232
361	P - Structures	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	13,112	6,086	13	180	2,855	880	2,295	726	0	726	1	24	11	43
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	13,112	6,086	13	180	2,855	880	2,295	726	0	726	1	24	11	43
362	P - Station	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	216,798	100,629	217	2,971	47,199	14,546	37,945	12,005	0	12,005	16	389	177	704
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	216,798	100,629	217	2,971	47,199	14,546	37,945	12,005	0	12,005	16	389	177	704
364P	P - Primary Poles	DIST_CUST	17,959	0	0	0	0	0	17,366	593	0	593	0	0	0	0
		DIST_DEMAND	5,065	0	0	0	0	0	3,848	1,217	0	1,217	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	23,024	0	0	0	0	0	21,214	1,810	0	1,810	0	0	0	0
364S	P - Secondary Poles	DIST_CUST	250,038	220,159	121	18,028	10,747	156	0	0	0	0	25	60	477	267
		DIST_DEMAND	70,523	42,534	92	1,256	19,950	6,149	0	0	0	0	7	165	75	297
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	320,561	262,692	213	19,283	30,697	6,304	0	0	0	0	32	224	552	564

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
PLANT IN SERVICE, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
364Z	P - Streetlight Poles	DIST_CUST	10,626	0	0	0	0	0	0	0	0	0	0	0	0	10,626
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	10,626	0	0	0	0	0	0	0	0	0	0	0	0	10,626
365P	P - OH Prim. Conductors	DIST_CUST	46,249	0	0	0	0	0	44,722	1,527	0	1,527	0	0	0	0
		DIST_DEMAND	8,744	0	0	0	0	0	6,642	2,102	0	2,102	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	54,993	0	0	0	0	0	51,365	3,628	0	3,628	0	0	0	0
365S	P - OH Sec. Conductors	DIST_CUST	374,195	329,479	181	26,979	16,083	233	0	0	0	0	37	89	714	399
		DIST_DEMAND	70,745	42,668	92	1,260	20,013	6,168	0	0	0	0	7	165	75	298
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	444,940	372,147	273	28,239	36,096	6,401	0	0	0	0	44	254	789	698
366P	P - U Prim. Conduit	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	2,696	0	0	0	0	0	2,048	648	0	648	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,696	0	0	0	0	0	2,048	648	0	648	0	0	0	0
366S	P - U Sec. Conduit	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	27,600	16,646	36	491	7,808	2,406	0	0	0	0	3	64	29	116
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	27,600	16,646	36	491	7,808	2,406	0	0	0	0	3	64	29	116
367P	P - U Prim. Conductors	DIST_CUST	40,778	0	0	0	0	0	39,432	1,346	0	1,346	0	0	0	0
		DIST_DEMAND	5,351	0	0	0	0	0	4,065	1,286	0	1,286	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	46,129	0	0	0	0	0	43,497	2,632	0	2,632	0	0	0	0
367S	P - U Sec. Conductors	DIST_CUST	138,861	122,268	67	10,012	5,968	87	0	0	0	0	14	33	265	148
		DIST_DEMAND	18,222	10,990	24	324	5,155	1,589	0	0	0	0	2	43	19	77
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	157,083	133,257	91	10,336	11,123	1,675	0	0	0	0	15	76	284	225
368	P - XFMRs	DIST_CUST	284,784	250,753	138	20,533	12,240	177	0	0	0	0	28	68	543	304
		DIST_DEMAND	217,481	131,166	283	3,872	61,522	18,961	0	0	0	0	21	507	230	917
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	502,265	381,919	421	24,405	73,762	19,138	0	0	0	0	49	575	774	1,221
369	P - Services	DIST_CUST	169,525	149,267	82	12,223	7,286	106	0	0	0	0	17	40	323	181
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	169,525	149,267	82	12,223	7,286	106	0	0	0	0	17	40	323	181
370	P - Meters	DIST_CUST	11,620	8,316	17	961	965	104	975	270	270	0	2	12	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	11,620	8,316	17	961	965	104	975	270	270	0	2	12	0	0
371	P - Customer Premises	DIST_CUST	4,520	0	0	0	0	0	0	0	0	0	0	0	4,520	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
PLANT IN SERVICE, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
		Total	4,520	0	0	0	0	0	0	0	0	0	0	0	4,520	0
372	P - Leased Property Cust. Prem.	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
373	P - Streetlight	DIST_CUST	12,289	0	0	0	0	0	0	0	0	0	0	0	0	12,289
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	12,289	0	0	0	0	0	0	0	0	0	0	0	0	12,289
	Dist Original Cost Plant	**DIST_CUST**	1,382,938	1,097,525	614	90,150	54,133	875	104,132	3,791	270	3,521	124	307	6,880	24,406
		DIST_DEMAND	666,980	356,374	769	10,521	167,153	51,516	57,805	18,288	-	18,288	57	1,379	626	2,492
		DIST_ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Total	2,049,918	1,453,899	1,383	100,671	221,286	52,390	161,937	22,080	270	21,810	181	1,686	7,506	26,898
General Plant																
389	P - Land	DIST_CUST	1,813	1,439	1	118	71	1	137	5	0	5	0	0	9	32
		DIST_DEMAND	875	467	1	14	219	68	76	24	0	24	0	2	1	3
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,688	1,906	2	132	290	69	212	29	0	29	0	2	10	35
390	P - Structures	DIST_CUST	56,136	44,551	25	3,659	2,197	35	4,227	154	11	143	5	12	279	991
		DIST_DEMAND	27,074	14,466	31	427	6,785	2,091	2,346	742	0	742	2	56	25	101
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	83,210	59,016	56	4,086	8,982	2,127	6,573	896	11	885	7	68	305	1,092
391	P - Office Equipment	DIST_CUST	21,531	17,087	10	1,404	843	14	1,621	59	4	55	2	5	107	380
		DIST_DEMAND	10,384	5,548	12	164	2,602	802	900	285	0	285	1	21	10	39
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	31,915	22,636	22	1,567	3,445	816	2,521	344	4	340	3	26	117	419
392	P - Transportation	DIST_CUST	2,912	2,311	1	190	114	2	219	8	1	7	0	1	14	51
		DIST_DEMAND	1,404	750	2	22	352	108	122	39	0	39	0	3	1	5
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	4,316	3,061	3	212	466	110	341	46	1	46	0	4	16	57
393	P - Stores Equipment	DIST_CUST	793	629	0	52	31	1	60	2	0	2	0	0	4	14
		DIST_DEMAND	382	204	0	6	96	30	33	10	0	10	0	1	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	1,175	833	1	58	127	30	93	13	0	13	0	1	4	15

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
PLANT IN SERVICE, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
394	P - Tools & Garage Equip.	DIST_CUST	6,578	5,220	3	429	257	4	495	18	1	17	1	1	33	116
		DIST_DEMAND	3,172	1,695	4	50	795	245	275	87	0	87	0	7	3	12
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	9,750	6,915	7	479	1,052	249	770	105	1	104	1	8	36	128
395	P - Laboratory	DIST_CUST	1,712	1,358	1	112	67	1	129	5	0	4	0	0	9	30
		DIST_DEMAND	825	441	1	13	207	64	72	23	0	23	0	2	1	3
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,537	1,799	2	125	274	65	200	27	0	27	0	2	9	33
396	P - Power Equipment	DIST_CUST	422	335	0	28	17	0	32	1	0	1	0	0	2	7
		DIST_DEMAND	204	109	0	3	51	16	18	6	0	6	0	0	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	626	444	0	31	68	16	49	7	0	7	0	1	2	8
397	P - Communication Equipment	DIST_CUST	10,788	8,562	5	703	422	7	812	30	2	27	1	2	54	190
		DIST_DEMAND	5,203	2,780	6	82	1,304	402	451	143	0	143	0	11	5	19
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	15,991	11,342	11	785	1,726	409	1,263	172	2	170	1	13	59	210
398	P - Misc. Equipment	DIST_CUST	1,452	1,153	1	95	57	1	109	4	0	4	0	0	7	26
		DIST_DEMAND	701	374	1	11	176	54	61	19	0	19	0	1	1	3
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,153	1,527	1	106	232	55	170	23	0	23	0	2	8	28
	Gen Original Cost Plant	**DIST_CUST**	104,137	82,645	46	6,788	4,076	66	7,841	285	20	265	9	23	518	1,838
		DIST_DEMAND	50,224	26,835	58	792	12,587	3,879	4,353	1,377	0	1,377	4	104	47	188
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	154,361	109,480	104	7,581	16,663	3,945	12,194	1,663	20	1,642	14	127	565	2,025
TOTAL PLANT IN SERVICE																
	Rate Base - Plant in Service	**DIST_CUST**	1,539,447	1,224,806	684	99,751	60,022	1,007	114,485	4,210	347	3,863	136	337	7,465	26,544
		DIST_DEMAND	726,408	387,822	837	11,450	181,901	56,061	63,342	20,040	0	20,040	62	1,500	681	2,712
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,265,855	1,612,628	1,521	111,200	241,923	57,068	177,827	24,250	347	23,903	198	1,837	8,146	29,257

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
DEPRECIATION RESERVE, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
Intangible Plant																
108_302	AD - Franchise & Consents	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
108_303	AD - Intangible	DIST_CUST	26,685	22,749	12	1,432	923	34	1,277	68	29	39	1	3	34	152
		DIST_DEMAND	4,660	2,333	5	69	1,093	337	602	190	0	190	0	9	4	16
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	31,345	25,083	17	1,501	2,016	371	1,879	258	29	229	1	12	38	168
	Rate Base - Intangible Plant Accumulated Depreciation Total	**DIST_CUST**	**26,685**	**22,749**	**12**	**1,432**	**923**	**34**	**1,277**	**68**	**29**	**39**	**1**	**3**	**34**	**152**
		DIST_DEMAND	**4,660**	**2,333**	**5**	**69**	**1,093**	**337**	**602**	**190**	**0**	**190**	**0**	**9**	**4**	**16**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**31,345**	**25,083**	**17**	**1,501**	**2,016**	**371**	**1,879**	**258**	**29**	**229**	**1**	**12**	**38**	**168**
Distribution Plant																
108_360	AD - Land	DIST_CUST	10,051	8,082	4	662	395	6	765	26	0	26	1	2	18	90
		DIST_DEMAND	4,976	2,644	6	78	1,240	382	450	142	0	142	0	10	5	18
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	15,027	10,726	10	740	1,635	388	1,215	168	0	168	1	12	22	108
108_361	AD - Structures	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	6,600	3,063	7	90	1,437	443	1,155	365	0	365	0	12	5	21
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	6,600	3,063	7	90	1,437	443	1,155	365	0	365	0	12	5	21
108_362	AD - Station	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	76,801	35,648	77	1,052	16,720	5,153	13,442	4,253	0	4,253	6	138	63	249
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	76,801	35,648	77	1,052	16,720	5,153	13,442	4,253	0	4,253	6	138	63	249
108_364	AD - Poles	DIST_CUST	88,957	70,291	39	5,756	3,431	50	5,544	189	0	189	8	19	152	3,478
		DIST_DEMAND	25,090	13,463	29	397	6,315	1,946	2,102	665	0	665	2	52	24	94
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			114,047	83,754	68	6,153	9,746	1,996	7,647	854	0	854	10	71	176	3,572
108_365	AD - Conductors	DIST_CUST	91,397	71,623	39	5,865	3,496	51	9,722	332	0	332	8	19	155	87
		DIST_DEMAND	17,280	9,275	20	274	4,350	1,341	1,444	457	0	457	1	36	16	65
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	108,677	80,898	59	6,139	7,847	1,391	11,166	789	0	789	10	55	171	152
108_366	AD - Underground Conduit	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	11,950	6,566	14	194	3,080	949	808	256	0	256	1	25	12	46
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	11,950	6,566	14	194	3,080	949	808	256	0	256	1	25	12	46
108_367	AD - Underground Conductors	DIST_CUST	69,210	47,106	26	3,857	2,299	33	15,192	519	0	519	5	13	102	57
		DIST_DEMAND	9,082	4,234	9	125	1,986	612	1,566	495	0	495	1	16	7	30
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	78,292	51,340	35	3,982	4,285	645	16,758	1,014	0	1,014	6	29	109	87
108_368	AD - XFMRs	DIST_CUST	75,396	66,387	36	5,436	3,241	47	0	0	0	0	7	18	144	80
		DIST_DEMAND	57,578	34,726	75	1,025	16,288	5,020	0	0	0	0	6	134	61	243

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
DEPRECIATION RESERVE, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	132,974	101,113	111	6,461	19,528	5,067	0	0	0	0	13	152	205	323
108_369	AD - Services	DIST_CUST	72,633	63,953	35	5,237	3,122	45	0	0	0	0	7	17	139	77
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	72,633	63,953	35	5,237	3,122	45	0	0	0	0	7	17	139	77
108_370	AD - Meters	DIST_CUST	499	357	1	41	41	4	42	12	12	0	0	1	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	499	357	1	41	41	4	42	12	12	0	0	1	0	0
108_371	AD - Customer Premises	DIST_CUST	2,719	0	0	0	0	0	0	0	0	0	0	0	2,719	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,719	0	0	0	0	0	0	0	0	0	0	0	2,719	0
108_372	AD - Leased Property Cust. Prem.	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
108_373	AD - Streetlights	DIST_CUST	3,508	0	0	0	0	0	0	0	0	0	0	0	0	3,508
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	3,508	0	0	0	0	0	0	0	0	0	0	0	0	3,508
	Rate Base Accumulated Depreciation Distribution Plant	**DIST_CUST**	**414,370**	**327,800**	**180**	**26,854**	**16,025**	**236**	**31,266**	**1,077**	**12**	**1,066**	**37**	**89**	**3,428**	**7,377**
		DIST_DEMAND	**209,357**	**109,620**	**236**	**3,236**	**51,416**	**15,846**	**20,967**	**6,634**	**0**	**6,634**	**18**	**424**	**193**	**767**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**623,727**	**437,420**	**417**	**30,090**	**67,441**	**16,082**	**52,233**	**7,711**	**12**	**7,700**	**54**	**513**	**3,621**	**8,144**
General Plant																
108_389	AD - Land	DIST_CUST	9	7	0	1	0	0	1	0	0	0	0	0	0	0
		DIST_DEMAND	4	2	0	0	1	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	13	9	0	1	1	0	1	0	0	0	0	0	0	0

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
DEPRECIATION RESERVE, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
108_390	AD - Structures	DIST_CUST	32,048	25,434	14	2,089	1,254	20	2,413	88	6	82	3	7	159	566
		DIST_DEMAND	15,457	8,259	18	244	3,874	1,194	1,340	424	0	424	1	32	15	58
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	47,505	33,693	32	2,333	5,128	1,214	3,753	512	6	505	4	39	174	623
108_391	AD - Office Equipment	DIST_CUST	15,650	12,420	7	1,020	613	10	1,178	43	3	40	1	3	78	276
		DIST_DEMAND	7,548	4,033	9	119	1,892	583	654	207	0	207	1	16	7	28
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	23,198	16,453	16	1,139	2,504	593	1,833	250	3	247	2	19	85	304
108_392	AD - Transportation	DIST_CUST	414	328	0	27	16	0	31	1	0	1	0	0	2	7
		DIST_DEMAND	199	107	0	3	50	15	17	5	0	5	0	0	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	613	435	0	30	66	16	48	7	0	7	0	1	2	8
108_393	AD - Stores Equip.	DIST_CUST	793	629	0	52	31	1	60	2	0	2	0	0	4	14
		DIST_DEMAND	382	204	0	6	96	30	33	10	0	10	0	1	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	1,175	833	1	58	127	30	93	13	0	13	0	1	4	15
108_394	AD - Tools & Garage Equip.	DIST_CUST	4,357	3,458	2	284	171	3	328	12	1	11	0	1	22	77
		DIST_DEMAND	2,101	1,123	2	33	527	162	182	58	0	58	0	4	2	8
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	6,458	4,580	4	317	697	165	510	70	1	69	1	5	24	85
108_395	AD - Laboratory	DIST_CUST	1,712	1,358	1	112	67	1	129	5	0	4	0	0	9	30
		DIST_DEMAND	825	441	1	13	207	64	72	23	0	23	0	2	1	3
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,537	1,799	2	125	274	65	200	27	0	27	0	2	9	33
108_396	AD - Power Equipment	DIST_CUST	349	277	0	23	14	0	26	1	0	1	0	0	2	6
		DIST_DEMAND	169	90	0	3	42	13	15	5	0	5	0	0	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	518	367	0	25	56	13	41	6	0	6	0	0	2	7
108_397	AD - Communication Equip.	DIST_CUST	8,135	6,456	4	530	318	5	613	22	2	21	1	2	40	144
		DIST_DEMAND	3,924	2,096	5	62	983	303	340	108	0	108	0	8	4	15
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	12,059	8,553	8	592	1,302	308	953	130	2	128	1	10	44	158
108_398	AD - Misc. Equipment	DIST_CUST	1,452	1,153	1	95	57	1	109	4	0	4	0	0	7	26
		DIST_DEMAND	701	374	1	11	176	54	61	19	0	19	0	1	1	3
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,153	1,527	1	106	232	55	170	23	0	23	0	2	8	28
	Rate Base Total Accumulated Depreciation General Plant	**DIST_CUST**	**64,919**	**51,521**	**29**	**4,232**	**2,541**	**41**	**4,888**	**178**	**13**	**165**	**6**	**14**	**323**	**1,146**
		DIST_DEMAND	**31,310**	**16,729**	**36**	**494**	**7,847**	**2,418**	**2,714**	**859**	**0**	**859**	**3**	**65**	**29**	**117**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**96,229**	**68,250**	**65**	**4,726**	**10,388**	**2,459**	**7,602**	**1,036**	**13**	**1,024**	**9**	**79**	**352**	**1,263**

TOTAL PLANT ACCUMULATED DEPRECIATION

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
DEPRECIATION RESERVE, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
	Rate Base Total Accumulated Depreciation	DIST_CUST	505,974	402,070	221	32,517	19,489	312	37,431	1,323	53	1,270	44	107	3,785	8,675
		DIST_DEMAND	245,327	128,683	278	3,799	60,356	18,601	24,283	7,683	0	7,682	21	498	226	900
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	751,301	530,752	499	36,317	79,845	18,913	61,713	9,006	53	8,953	64	605	4,011	9,575

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
RATE BASE ADJUSTMENTS, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
RATE BASE ADDITIONS																
ADJ_RB_5	RB Adj. M&S	DIST_CUST	9,778	7,760	4	637	383	6	736	27	2	25	1	2	49	173
		DIST_DEMAND	4,716	2,520	5	74	1,182	364	409	129	0	129	0	10	4	18
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	14,493	10,279	10	712	1,565	370	1,145	156	2	154	1	12	53	190
CWC	Cash Working Capital	DIST_CUST	99,729	79,147	44	6,501	3,904	63	7,509	273	19	254	9	22	496	1,760
		DIST_DEMAND	48,099	25,700	55	759	12,054	3,715	4,169	1,319	0	1,319	4	99	45	180
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	147,828	104,847	100	7,260	15,958	3,778	11,678	1,592	19	1,573	13	122	541	1,940
ADJ_RB_6	RB Adj. Storm Damage Normalization	DIST_CUST	43,827	34,782	19	2,857	1,716	28	3,300	120	9	112	4	10	218	773
		DIST_DEMAND	21,137	11,294	24	333	5,297	1,633	1,832	580	0	580	2	44	20	79
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	64,964	46,076	44	3,190	7,013	1,660	5,132	700	9	691	6	53	238	852
ADJ_RB_7	RB Adj. Adjustment for Retired Legacy Meters	DIST_CUST	35,979	28,932	16	2,369	1,412	20	2,740	94	0	94	3	8	63	322
		DIST_DEMAND	17,814	9,466	20	279	4,440	1,368	1,610	509	0	509	2	37	17	66
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		PWR_SUP_E	53,794	38,399	36	2,649	5,852	1,389	4,350	603	0	603	5	44	79	388
	Rate Base Additions	**DIST_CUST**	**189,313**	**150,621**	**84**	**12,365**	**7,414**	**117**	**14,286**	**514**	**30**	**484**	**17**	**42**	**825**	**3,028**
		DIST_DEMAND	**91,766**	**48,979**	**106**	**1,446**	**22,973**	**7,080**	**8,019**	**2,537**	**0**	**2,537**	**8**	**189**	**86**	**343**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**281,079**	**199,600**	**190**	**13,810**	**30,387**	**7,198**	**22,305**	**3,051**	**30**	**3,021**	**25**	**231**	**911**	**3,370**
RATE BASE SUBTRACTIONS																
235	Customer Deposits	DIST_CUST	20,925	11,625	17	4,496	2,680	537	1,414	151	151	0	0	4	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	20,925	11,625	17	4,496	2,680	537	1,414	151	151	0	0	4	0	0
252	Customer Advances	DIST_CUST	19	19	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	19	19	0	0	0	0	0	0	0	0	0	0	0	0
RB_DIT_LIB	Deferred Tax - Liberalized Depreciation	DIST_CUST	243,688	193,395	108	15,885	9,539	154	18,349	668	48	621	22	54	1,212	4,301
		DIST_DEMAND	117,529	62,797	135	1,854	29,454	9,078	10,186	3,223	0	3,223	10	243	110	439
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	361,217	256,192	244	17,739	38,993	9,232	28,535	3,891	48	3,843	32	297	1,323	4,740
RB_OP_RES	Operating Reserves	DIST_CUST	342	272	0	22	13	0	26	1	0	1	0	0	2	6
		DIST_DEMAND	165	88	0	3	41	13	14	5	0	5	0	0	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	508	360	0	25	55	13	40	5	0	5	0	0	2	7
	Rate Base Deductions	**DIST_CUST**	**264,975**	**205,311**	**126**	**20,404**	**12,233**	**692**	**19,789**	**820**	**199**	**621**	**22**	**58**	**1,214**	**4,307**
		DIST_DEMAND	**117,694**	**62,885**	**136**	**1,856**	**29,495**	**9,090**	**10,200**	**3,227**	**0**	**3,227**	**10**	**243**	**110**	**440**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**382,669**	**268,196**	**261**	**22,261**	**41,728**	**9,782**	**29,989**	**4,047**	**199**	**3,849**	**32**	**301**	**1,324**	**4,746**
TOTAL RATE BASE ADJUSTMENTS																

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
RATE BASE ADJUSTMENTS, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
	Rate Base Total	DIST_CUST	957,811	768,046	421	59,194	35,714	122	71,551	2,581	125	2,456	87	214	3,291	16,591
		DIST_DEMAND	455,154	245,233	529	7,240	115,023	35,449	36,878	11,667	0	11,667	39	949	431	1,715
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	1,412,965	1,013,279	950	66,434	150,737	35,571	108,429	14,248	125	14,123	126	1,162	3,722	18,306

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
REVENUE, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
Tariff Revenue																
400_D	Distribution Revenue w/o USR	DIST_CUST	191,078	154,558	180	8,434	12,730	296	8,865	1,084	866	218	16	102	610	4,204
		DIST_DEMAND	75,268	31,496	165	538	30,671	5,689	4,517	1,310	1	1,309	6	377	58	440
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	266,346	186,054	344	8,972	43,400	5,985	13,382	2,395	868	1,527	22	479	668	4,644
	Tariff Revenue Total	**DIST_CUST**	**191,078**	**154,558**	**180**	**8,434**	**12,730**	**296**	**8,865**	**1,084**	**866**	**218**	**16**	**102**	**610**	**4,204**
		DIST_DEMAND	**75,268**	**31,496**	**165**	**538**	**30,671**	**5,689**	**4,517**	**1,310**	**1**	**1,309**	**6**	**377**	**58**	**440**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**266,346**	**186,054**	**344**	**8,972**	**43,400**	**5,985**	**13,382**	**2,395**	**868**	**1,527**	**22**	**479**	**668**	**4,644**
Other Revenues																
450	OR - Forefeited Discount Revenue	DIST_CUST	3,229	2,843	2	234	138	2	3	0	0	0	0	0	6	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	3,229	2,843	2	234	138	2	3	0	0	0	0	0	6	0
451	OR - Misc. Service Revenues	DIST_CUST	1,903	1,676	1	137	82	1	0	0	0	0	0	0	4	2
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	1,903	1,676	1	137	82	1	0	0	0	0	0	0	4	2
454POLE	OR - Pole Rent	DIST_CUST	6,121	4,837	3	396	236	3	382	13	0	13	1	1	10	239
		DIST_DEMAND	1,727	926	2	27	435	134	145	46	0	46	0	4	2	6
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	7,848	5,763	5	423	671	137	526	59	0	59	1	5	12	246
454RENT	OR - Lease Rent	DIST_CUST	4,300	3,537	3	280	196	6	203	16	10	6	0	1	6	51
		DIST_DEMAND	1,270	626	1	19	293	90	177	56	0	56	0	2	1	4
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	5,570	4,163	4	298	489	97	380	72	10	61	0	3	7	56
456MISC	OR - Misc. Revenue	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
456AECNITS	OR - AEC wheeling NITS	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
456SCRAP	OR - NUG/TMI	DIST_CUST	29	23	0	2	1	0	2	0	0	0	0	0	0	0
		DIST_DEMAND	14	8	0	0	4	1	1	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	43	31	0	2	5	1	3	0	0	0	0	0	0	0
	Other Revenue Total	**DIST_CUST**	**15,582**	**12,916**	**8**	**1,049**	**653**	**13**	**590**	**29**	**11**	**19**	**1**	**3**	**27**	**293**
		DIST_DEMAND	**3,011**	**1,560**	**3**	**46**	**731**	**225**	**323**	**102**	**0**	**102**	**0**	**6**	**3**	**11**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**18,593**	**14,476**	**11**	**1,095**	**1,385**	**238**	**913**	**131**	**11**	**121**	**1**	**9**	**30**	**304**
TOTAL REVENUE																

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
REVENUE, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
	Retail Total Revenue	DIST_CUST	206,660	167,474	188	9,483	13,383	309	9,455	1,114	877	237	17	104	637	4,497
		DIST_DEMAND	78,279	33,056	168	585	31,402	5,914	4,840	1,412	1	1,411	6	383	61	451
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	284,939	200,530	356	10,067	44,785	6,223	14,294	2,526	878	1,648	23	488	698	4,948

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
O & M EXPENSES, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
Distribution																
580	OP - Supv. & Engineering	DIST_CUST	58	46	0	4	3	0	5	0	0	0	0	0	0	1
		DIST_DEMAND	39	22	0	1	8	2	4	1	0	1	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	97	68	0	5	10	2	8	2	1	1	0	0	0	1
581	OP - Dispatching	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	339	157	0	5	74	23	59	19	0	19	0	1	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	339	157	0	5	74	23	59	19	0	19	0	1	0	1
582	OP - Station expenses	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	615	285	1	8	134	41	108	34	0	34	0	1	1	2
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	615	285	1	8	134	41	108	34	0	34	0	1	1	2
583	OP - Overhead Line	DIST_CUST	31	24	0	2	1	0	3	0	0	0	0	0	0	0
		DIST_DEMAND	6	3	0	0	1	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	37	28	0	2	3	0	4	0	0	0	0	0	0	0
584	OP - Underground lines expenses	DIST_CUST	509	347	0	28	17	0	112	4	0	4	0	0	1	0
		DIST_DEMAND	67	31	0	1	15	5	12	4	0	4	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		PWR_SUP_E	576	378	0	29	32	5	123	7	0	7	0	0	1	1
586	OP - Meter	DIST_CUST	771	552	1	64	64	7	65	18	18	0	0	1	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	771	552	1	64	64	7	65	18	18	0	0	1	0	0
588	OP - Misc. Expenses	DIST_CUST	3,339	2,650	1	218	131	2	251	9	1	9	0	1	17	59
		DIST_DEMAND	1,610	860	2	25	404	124	140	44	0	44	0	3	2	6
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	4,949	3,510	3	243	534	126	391	53	1	53	0	4	18	65
589	MN - Rents	DIST_CUST	365	290	0	24	14	0	27	1	0	1	0	0	2	6
		DIST_DEMAND	176	94	0	3	44	14	15	5	0	5	0	0	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	541	384	0	27	58	14	43	6	0	6	0	0	2	7
590	MN - Supv. & Engineering	DIST_CUST	282	216	0	18	12	0	29	1	1	1	0	0	0	4
		DIST_DEMAND	108	54	0	2	25	8	15	5	0	5	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	390	270	0	20	37	8	44	6	1	6	0	0	1	4
591	MN - Structures	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	16	7	0	0	3	1	3	1	0	1	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	16	7	0	0	3	1	3	1	0	1	0	0	0	0
592	MN - Station	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	4,043	1,877	4	55	880	271	708	224	0	224	0	7	3	13

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
O & M EXPENSES, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	4,043	1,877	4	55	880	271	708	224	0	224	0	7	3	13
593	MN - OH Concuctors	DIST_CUST	17,016	13,334	7	1,092	651	9	1,810	62	0	62	1	4	29	16
		DIST_DEMAND	3,217	1,727	4	51	810	250	269	85	0	85	0	7	3	12
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	20,233	15,061	11	1,143	1,461	259	2,079	147	0	147	2	10	32	28
594	MN - UG Concuctors	DIST_CUST	1,810	1,232	1	101	60	1	397	14	0	14	0	0	3	1
		DIST_DEMAND	238	111	0	3	52	16	41	13	0	13	0	0	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,048	1,343	1	104	112	17	438	27	0	27	0	1	3	2
595	MN - XFMRs	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
596	MN - Streetlights	DIST_CUST	250	0	0	0	0	0	0	0	0	0	0	0	0	250
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	250	0	0	0	0	0	0	0	0	0	0	0	0	250
597	MN - Meters	DIST_CUST	1,645	1,177	2	136	137	15	138	38	38	0	0	2	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	1,645	1,177	2	136	137	15	138	38	38	0	0	2	0	0
598	MN - Maintenance of miscellaneous	DIST_CUST	963	765	0	63	38	1	73	3	0	2	0	0	5	17
		DIST_DEMAND	465	248	1	7	116	36	40	13	0	13	0	1	0	2
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		#REF!	1,428	1,013	1	70	154	36	113	15	0	15	0	1	5	19
ADJ_IS_4a	IS Adj. Distribution Payroll	DIST_CUST	209	158	0	14	10	0	19	2	1	1	0	0	0	5
		DIST_DEMAND	120	59	0	2	28	9	17	5	0	5	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	329	218	0	16	37	9	36	7	1	6	0	0	1	5

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
O & M EXPENSES, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
ADJ_IS_4c	IS Adj. Distribution Reaquired Debt	DIST_CUST	54	43	0	4	2	0	4	0	0	0	0	0	0	1
		DIST_DEMAND	26	14	0	0	7	2	2	1	0	1	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	81	57	0	4	9	2	6	1	0	1	0	0	0	1
	Total Distribution Expense	**DIST_CUST**	**27,303**	**20,834**	**14**	**1,767**	**1,139**	**36**	**2,933**	**152**	**59**	**93**	**3**	**8**	**57**	**361**
		DIST_DEMAND	**11,084**	**5,551**	**12**	**165**	**2,601**	**801**	**1,432**	**453**	**0**	**453**	**1**	**21**	**10**	**39**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**38,387**	**26,384**	**26**	**1,932**	**3,739**	**837**	**4,365**	**605**	**59**	**546**	**3**	**29**	**67**	**400**
Customer Accounts																
902	Customer Account Supervision	DIST_CUST	5,026	4,152	5	484	372	5	8	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	5,026	4,152	5	484	372	5	8	0	0	0	0	0	0	0
903	Customer Account Collections	DIST_CUST	5,858	5,158	3	425	251	4	5	0	0	0	0	0	12	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	5,858	5,158	3	425	251	4	5	0	0	0	0	0	12	0
904	Customer Account Uncollectables	DIST_CUST	4,733	4,168	2	344	203	3	4	0	0	0	0	0	9	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	4,733	4,168	2	344	203	3	4	0	0	0	0	0	9	0
905	Customer Account Accounts	DIST_CUST	251	221	0	18	11	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	251	221	0	18	11	0	0	0	0	0	0	0	0	0
ADJ_IS_5a	IS Adj. Customer Accounts Payroll	DIST_CUST	191	162	0	17	12	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	191	162	0	17	12	0	0	0	0	0	0	0	0	0
ADJ_IS_5b	IS Adj. Customer Accounts Deposits	DIST_CUST	1,256	698	1	270	161	32	85	9	9	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	1,256	698	1	270	161	32	85	9	9	0	0	0	0	0
ADJ_IS_5c	IS Adj. Customer Accounts Uncollectables	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
O & M EXPENSES, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
ADJ_IS_5d	IS Adj. Customer Accounts No. of Cust.	DIST_CUST	10	9	0	1	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		#REF!	10	9	0	1	0	0	0	0	0	0	0	0	0	0
	Total Customer Account Expense	**DIST_CUST**	**17,325**	**14,567**	**11**	**1,558**	**1,009**	**45**	**103**	**10**	**10**	**0**	**0**	**0**	**22**	**0**
		DIST_DEMAND	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**17,325**	**14,567**	**11**	**1,558**	**1,009**	**45**	**103**	**10**	**10**	**0**	**0**	**0**	**22**	**0**
Customer Information																
907	Customer Info Supervision	DIST_CUST	304	298	0	4	2	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	304	298	0	4	2	0	0	0	0	0	0	0	0	0
908	Customer Info Assistance Dist.	DIST_CUST	12,834	12,834	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	12,834	12,834	0	0	0	0	0	0	0	0	0	0	0	0
909	Customer Info Advertising Dist.	DIST_CUST	130	114	0	9	6	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	130	114	0	9	6	0	0	0	0	0	0	0	0	0
910	Customer Info Misc. Expense	DIST_CUST	5,510	5,400	3	65	39	1	1	0	0	0	0	0	2	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	5,510	5,400	3	65	39	1	1	0	0	0	0	0	2	0
ADJ_IS_6	IS Adj. Customer Service Payroll	DIST_CUST	44	43	0	1	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	44	43	0	1	0	0	0	0	0	0	0	0	0	0
	Total Customer Service and Info Expense	**DIST_CUST**	**18,822**	**18,690**	**3**	**79**	**47**	**1**	**1**	**0**	**0**	**0**	**0**	**0**	**2**	**0**
		DIST_DEMAND	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**18,822**	**18,690**	**3**	**79**	**47**	**1**	**1**	**0**	**0**	**0**	**0**	**0**	**2**	**0**

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
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O & M EXPENSES, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
Sales																
913	Advertising expenses	DIST_CUST	25	22	0	2	1	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	25	22	0	2	1	0	0	0	0	0	0	0	0	0
	Total Sales Expense	**DIST_CUST**	**25**	**22**	**0**	**2**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		DIST_DEMAND	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**25**	**22**	**0**	**2**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Administrative and General																
920	A&G Salaries	DIST_CUST	(405)	(333)	(0)	(26)	(18)	(1)	(19)	(2)	(1)	(1)	(0)	(0)	(1)	(5)
		DIST_DEMAND	(119)	(59)	(0)	(2)	(28)	(8)	(17)	(5)	(0)	(5)	(0)	(0)	(0)	(0)
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	(524)	(392)	(0)	(28)	(46)	(9)	(36)	(7)	(1)	(6)	(0)	(0)	(1)	(5)
921	A&G Office Supplies	DIST_CUST	2,436	2,003	2	158	111	4	115	9	6	3	0	0	4	29
		DIST_DEMAND	719	355	1	11	166	51	100	32	0	32	0	1	1	2
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	3,155	2,358	2	169	277	55	215	41	6	35	0	2	4	32
922	A&G Admin. Expenses	DIST_CUST	(2,379)	(1,957)	(2)	(155)	(108)	(3)	(113)	(9)	(6)	(3)	(0)	(0)	(3)	(28)
		DIST_DEMAND	(703)	(346)	(1)	(10)	(162)	(50)	(98)	(31)	(0)	(31)	(0)	(1)	(1)	(2)
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	(3,082)	(2,304)	(2)	(165)	(271)	(53)	(210)	(40)	(6)	(34)	(0)	(2)	(4)	(31)
923	A&G Outside Services	DIST_CUST	8,550	7,033	6	556	390	13	405	32	21	11	0	2	12	102
		DIST_DEMAND	2,525	1,245	3	37	583	180	351	111	0	111	0	5	2	9
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	11,075	8,278	8	593	973	192	756	143	21	122	1	6	15	111
924	A&G Property Insurance	DIST_CUST	163	129	0	11	6	0	12	0	0	0	0	0	1	3
		DIST_DEMAND	79	42	0	1	20	6	7	2	0	2	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	242	171	0	12	26	6	19	3	0	3	0	0	1	3
925	A&G Injury and Damages	DIST_CUST	718	591	0	47	33	1	34	3	2	1	0	0	1	9
		DIST_DEMAND	212	105	0	3	49	15	29	9	0	9	0	0	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	930	695	1	50	82	16	63	12	2	10	0	1	1	9
926	A&G Pension and Benefits	DIST_CUST	(575)	(473)	(0)	(37)	(26)	(1)	(27)	(2)	(1)	(1)	(0)	(0)	(1)	(7)
		DIST_DEMAND	(170)	(84)	(0)	(2)	(39)	(12)	(24)	(7)	(0)	(7)	(0)	(0)	(0)	(1)
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	(745)	(557)	(1)	(40)	(65)	(13)	(51)	(10)	(1)	(8)	(0)	(0)	(1)	(7)
928	Regulatory Commission Expense	DIST_CUST	2,032	1,671	1	132	93	3	96	8	5	3	0	0	3	24
		DIST_DEMAND	600	296	1	9	138	43	83	26	0	26	0	1	1	2
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,632	1,967	2	141	231	46	180	34	5	29	0	2	3	26
930_1	A&G General Advertising	DIST_CUST	8	6	0	1	0	0	0	0	0	0	0	0	0	0

Total - Summary

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O & M EXPENSES, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
		DIST_DEMAND	2	1	0	0	1	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	10	7	0	1	1	0	1	0	0	0	0	0	0	0
930_2	A&G Misc. Expense	DIST_CUST	539	443	0	35	25	1	25	2	1	1	0	0	1	6
		DIST_DEMAND	159	78	0	2	37	11	22	7	0	7	0	0	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	698	522	1	37	61	12	48	9	1	8	0	0	1	7
931	A&G Misc. Rent	DIST_CUST	1,244	1,024	1	81	57	2	59	5	3	2	0	0	2	15
		DIST_DEMAND	368	181	0	5	85	26	51	16	0	16	0	1	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	1,612	1,205	1	86	142	28	110	21	3	18	0	1	2	16
935	A&G Maint. Of General Plant	DIST_CUST	540	429	0	35	21	0	41	1	0	1	0	0	3	10
		DIST_DEMAND	261	139	0	4	65	20	23	7	0	7	0	1	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	801	568	1	39	86	20	63	9	0	9	0	1	3	11
ADJ_IS_7a	IS Adj. Cash Pension	DIST_CUST	10,843	8,919	7	705	494	16	513	40	26	14	1	2	16	129
		DIST_DEMAND	3,203	1,579	3	47	739	228	445	141	0	141	0	6	3	11
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	14,046	10,498	11	752	1,233	244	959	181	26	155	1	8	18	141
ADJ_IS_7b	IS Adj. Other Employee Benefit Costs	DIST_CUST	2,581	2,123	2	168	118	4	122	10	6	3	0	0	4	31
		DIST_DEMAND	762	376	1	11	176	54	106	34	0	34	0	1	1	3
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	3,343	2,498	3	179	294	58	228	43	6	37	0	2	4	33
ADJ_IS_7c	IS Adj. A&G Non-Juris. Expense	DIST_CUST	(2,054)	(1,689)	(1)	(134)	(94)	(3)	(97)	(8)	(5)	(3)	(0)	(0)	(3)	(25)
		DIST_DEMAND	(607)	(299)	(1)	(9)	(140)	(43)	(84)	(27)	(0)	(27)	(0)	(1)	(1)	(2)
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	(2,660)	(1,988)	(2)	(142)	(234)	(46)	(182)	(34)	(5)	(29)	(0)	(2)	(3)	(27)
ADJ_IS_7d	IS Adj. A&G Rate Case Expense	DIST_CUST	(388)	(319)	(0)	(25)	(18)	(1)	(18)	(1)	(1)	(1)	(0)	(0)	(1)	(5)
		DIST_DEMAND	(115)	(56)	(0)	(2)	(26)	(8)	(16)	(5)	(0)	(5)	(0)	(0)	(0)	(0)
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	(502)	(375)	(0)	(27)	(44)	(9)	(34)	(6)	(1)	(6)	(0)	(0)	(1)	(5)
ADJ_IS_7e	IS Adj. A&G Legacy Meters	DIST_CUST	(330)	(290)	(0)	(24)	(14)	(0)	(0)	(0)	(0)	0	(0)	(0)	(1)	(0)
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	(330)	(290)	(0)	(24)	(14)	(0)	(0)	(0)	(0)	0	(0)	(0)	(1)	(0)
ADJ_IS_7f	IS Adj. Accelerated Switching	DIST_CUST	238	196	0	15	11	0	12	1	1	0	0	0	0	3
		DIST_DEMAND	73	36	0	1	17	5	10	3	0	3	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	311	232	0	17	28	6	21	4	1	3	0	0	0	3
	Total A & G Expense	**DIST_CUST**	**23,761**	**19,505**	**16**	**1,543**	**1,080**	**34**	**1,160**	**89**	**57**	**32**	**1**	**5**	**37**	**291**
		DIST_DEMAND	**7,250**	**3,588**	**8**	**107**	**1,680**	**518**	**991**	**313**	**0**	**313**	**1**	**14**	**6**	**25**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**31,011**	**23,094**	**23**	**1,650**	**2,759**	**552**	**2,150**	**402**	**57**	**345**	**2**	**18**	**43**	**316**

Total - Summary

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FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
O & M EXPENSES, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
	Total O & M Expense	DIST_CUST	87,236	73,618	44	4,949	3,275	116	4,197	251	126	125	4	12	118	653
		DIST_DEMAND	18,334	9,139	20	271	4,281	1,319	2,422	766	1	766	1	35	16	64
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	105,570	82,757	64	5,220	7,556	1,435	6,619	1,017	126	891	5	48	134	716

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
DEPRECIATION & AMORTIZATION, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
Depreciation																
403_303	DE - Intangible	DIST_CUST	6,869	5,856	3	369	238	9	329	17	7	10	0	1	9	39
		DIST_DEMAND	1,200	601	1	18	281	87	155	49	0	49	0	2	1	4
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	8,069	6,457	4	386	519	96	484	67	7	59	0	3	10	43
403_360	DE - Land	DIST_CUST	6	5	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	3	2	0	0	1	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	9	6	0	0	1	0	1	0	0	0	0	0	0	0
403_361	DE - Structures	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	310	144	0	4	67	21	54	17	0	17	0	1	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	310	144	0	4	67	21	54	17	0	17	0	1	0	1
403_362	DE - Station	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	3,382	1,570	3	46	736	227	592	187	0	187	0	6	3	11
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	3,382	1,570	3	46	736	227	592	187	0	187	0	6	3	11
403_364	DE - Poles	DIST_CUST	3,647	2,882	2	236	141	2	227	8	0	8	0	1	6	143
		DIST_DEMAND	1,029	552	1	16	259	80	86	27	0	27	0	2	1	4
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	4,676	3,434	3	252	400	82	314	35	0	35	0	3	7	146
403_365	DE - OH Conductors	DIST_CUST	6,979	5,469	3	448	267	4	742	25	0	25	1	1	12	7
		DIST_DEMAND	1,320	708	2	21	332	102	110	35	0	35	0	3	1	5
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	8,299	6,178	5	469	599	106	853	60	0	60	1	4	13	12
403_366	DE - Underground Conduit	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	527	290	1	9	136	42	36	11	0	11	0	1	1	2
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	527	290	1	9	136	42	36	11	0	11	0	1	1	2
403_367	DE - Underground Conductors	DIST_CUST	5,120	3,485	2	285	170	2	1,124	38	0	38	0	1	8	4
		DIST_DEMAND	672	313	1	9	147	45	116	37	0	37	0	1	1	2
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	5,792	3,798	3	295	317	48	1,240	75	0	75	0	2	8	6

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
DEPRECIATION & AMORTIZATION, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
403_368	DE - XFMRs	DIST_CUST	6,094	5,366	3	439	262	4	0	0	0	0	1	1	12	7
		DIST_DEMAND	4,654	2,807	6	83	1,317	406	0	0	0	0	0	11	5	20
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	10,748	8,173	9	522	1,578	410	0	0	0	0	1	12	17	26
403_369	DE - Services	DIST_CUST	3,816	3,360	2	275	164	2	0	0	0	0	0	1	7	4
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	3,816	3,360	2	275	164	2	0	0	0	0	0	1	7	4
403_370	DE - Meters	DIST_CUST	775	555	1	64	64	7	65	18	18	0	0	1	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	775	555	1	64	64	7	65	18	18	0	0	1	0	0
403_371	DE - Customer Premises	DIST_CUST	144	0	0	0	0	0	0	0	0	0	0	0	144	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	144	0	0	0	0	0	0	0	0	0	0	0	144	0
403_372	DE - Leased Property Cust. Prem.	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
403_373	DE - Streetlight	DIST_CUST	340	0	0	0	0	0	0	0	0	0	0	0	0	340
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	340	0	0	0	0	0	0	0	0	0	0	0	0	340
403_389	DE - Land	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
403_390	DE - Structures	DIST_CUST	1,450	1,151	1	95	57	1	109	4	0	4	0	0	7	26
		DIST_DEMAND	700	374	1	11	175	54	61	19	0	19	0	1	1	3
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,150	1,525	1	106	232	55	170	23	0	23	0	2	8	28
403_391	DE - Office Equipment	DIST_CUST	1,813	1,439	1	118	71	1	137	5	0	5	0	0	9	32
		DIST_DEMAND	875	467	1	14	219	68	76	24	0	24	0	2	1	3
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,688	1,906	2	132	290	69	212	29	0	29	0	2	10	35

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
DEPRECIATION & AMORTIZATION, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
403_392	DE - Transportation	DIST_CUST	138	110	0	9	5	0	10	0	0	0	0	0	1	2
		DIST_DEMAND	67	36	0	1	17	5	6	2	0	2	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	205	145	0	10	22	5	16	2	0	2	0	0	1	3
403_393	DE - Stores Equipment	DIST_CUST	7	5	0	0	0	0	1	0	0	0	0	0	0	0
		DIST_DEMAND	3	2	0	0	1	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	10	7	0	0	1	0	1	0	0	0	0	0	0	0
403_394	DE - Tools & Garage Equip.	DIST_CUST	276	219	0	18	11	0	21	1	0	1	0	0	1	5
		DIST_DEMAND	133	71	0	2	33	10	12	4	0	4	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	409	290	0	20	44	10	32	4	0	4	0	0	1	5
403_395	DE - Laboratory	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
403_396	DE - Power Equipment	DIST_CUST	7	6	0	0	0	0	1	0	0	0	0	0	0	0
		DIST_DEMAND	4	2	0	0	1	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	11	8	0	1	1	0	1	0	0	0	0	0	0	0
403_397	DE - Communications Equipment	DIST_CUST	324	258	0	21	13	0	24	1	0	1	0	0	2	6
		DIST_DEMAND	157	84	0	2	39	12	14	4	0	4	0	0	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	481	341	0	24	52	12	38	5	0	5	0	0	2	6
403_398	DE - Misc. Equipment	DIST_CUST	27	21	0	2	1	0	2	0	0	0	0	0	0	0
		DIST_DEMAND	13	7	0	0	3	1	1	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	40	28	0	2	4	1	3	0	0	0	0	0	0	1
404_5	Amortization and depletion of utility plant	DIST_CUST	3,200	2,546	1	207	125	2	238	9	1	8	0	1	16	55
		DIST_DEMAND	1,510	806	2	24	378	117	132	42	0	42	0	3	1	6
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	4,710	3,352	3	231	503	119	370	50	1	50	0	4	17	61
ADJ_IS_8a	IS Adj - Cost of Removal/Salvage	DIST_CUST	(136)	(108)	(0)	(9)	(5)	(0)	(10)	(0)	(0)	(0)	(0)	(0)	(1)	(2)
		DIST_DEMAND	(65)	(35)	(0)	(1)	(16)	(5)	(6)	(2)	0	(2)	(0)	(0)	(0)	(0)
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	(201)	(143)	(0)	(10)	(22)	(5)	(16)	(2)	(0)	(2)	(0)	(0)	(1)	(3)

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
DEPRECIATION & AMORTIZATION, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
ADJ_IS_8c	IS Adj - Average net Salvage	DIST_CUST	5,410	4,294	2	353	212	3	407	15	1	14	0	1	27	95
		DIST_DEMAND	2,609	1,394	3	41	654	202	226	72	0	72	0	5	2	10
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	8,020	5,688	5	394	866	205	634	86	1	85	1	7	29	105
ADJ_IS_8d	IS Adj - DE Accelerated Dep. Legacy Meters	DIST_CUST	10,759	7,699	15	890	893	96	903	250	250	0	2	11	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	10,759	7,699	15	890	893	96	903	250	250	0	2	11	0	0
	Depreciation Expense	**DIST_CUST**	**57,069**	**44,618**	**36**	**3,821**	**2,689**	**134**	**4,330**	**391**	**278**	**113**	**6**	**21**	**259**	**763**
		DIST_DEMAND	**19,100**	**10,193**	**22**	**301**	**4,781**	**1,473**	**1,671**	**529**	**0**	**528**	**2**	**39**	**18**	**71**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**76,168**	**54,812**	**58**	**4,122**	**7,470**	**1,607**	**6,001**	**920**	**278**	**642**	**7**	**60**	**277**	**834**
Amortization																
407_Dist	Amortization - Rate Case Expense	DIST_CUST	(750)	(660)	(0)	(54)	(32)	(0)	(1)	(0)	(0)	0	(0)	(0)	(1)	(1)
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	(750)	(660)	(0)	(54)	(32)	(0)	(1)	(0)	(0)	0	(0)	(0)	(1)	(1)
407_SMT	Amortization - Smart Meter	DIST_CUST	104	74	0	9	9	1	9	2	2	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	104	74	0	9	9	1	9	2	2	0	0	0	0	0
407_SMIP	Amortization - SMIP Legacy Meters	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
407_WAV	Amortization - Waverly	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
DEPRECIATION & AMORTIZATION, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
411_10	Investment Tax Credit	DIST_CUST	33	26	0	2	1	0	3	0	0	0	0	0	0	1
		DIST_DEMAND	16	8	0	0	4	1	1	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	49	35	0	2	5	1	4	0	0	0	0	0	0	1
ADJ_IS_9	IS Adj - Amortization Expense	DIST_CUST	15,305	12,146	7	998	599	10	1,152	42	3	39	1	3	76	270
		DIST_DEMAND	7,381	3,944	9	116	1,850	570	640	202	0	202	1	15	7	28
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	22,686	16,090	15	1,114	2,449	580	1,792	244	3	241	2	19	83	298
	Total Amortization Expense	**DIST_CUST**	**14,692**	**11,587**	**7**	**954**	**577**	**10**	**1,163**	**44**	**5**	**39**	**1**	**3**	**75**	**270**
		DIST_DEMAND	**7,397**	**3,952**	**9**	**117**	**1,854**	**571**	**641**	**203**	**0**	**203**	**1**	**15**	**7**	**28**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**22,089**	**15,539**	**15**	**1,071**	**2,431**	**581**	**1,804**	**247**	**5**	**242**	**2**	**19**	**82**	**298**

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
TAXES OTHER THAN INCOME, $1,000s

ACCOUNT	DESCRIPTION	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
408_1GRT	OT - Gross Receipts Tax	DIST_CUST	11,274	9,119	11	498	751	17	523	64	51	13	1	6	36	248
		DIST_DEMAND	4,441	1,858	10	32	1,810	336	267	77	0	77	0	22	3	26
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	15,714	10,977	20	529	2,561	353	790	141	51	90	1	28	39	274
408_1LND	OT - Property Tax	DIST_CUST	1,432	1,139	1	93	56	1	106	4	0	4	0	0	7	25
		DIST_DEMAND	675	361	1	11	169	52	59	19	0	19	0	1	1	3
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,107	1,500	1	103	225	53	165	23	0	22	0	2	8	27
408_1PAY	OT - Payroll Tax	DIST_CUST	3,624	2,981	2	236	165	5	171	14	9	5	0	1	5	43
		DIST_DEMAND	1,070	528	1	16	247	76	149	47	0	47	0	2	1	4
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	4,694	3,508	4	251	412	81	320	61	9	52	0	3	6	47
408_1CAP	OT - Capital Stock Tax	DIST_CUST	101	81	0	7	4	0	8	0	0	0	0	0	0	2
		DIST_DEMAND	48	26	0	1	12	4	4	1	0	1	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	149	106	0	7	16	4	12	2	0	2	0	0	1	2
408_1MISC	OT - Misc. Tax	DIST_CUST	77	61	0	5	3	0	6	0	0	0	0	0	0	1
		DIST_DEMAND	36	19	0	1	9	3	3	1	0	1	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	113	80	0	6	12	3	9	1	0	1	0	0	0	1
ADJ_IS_10a	IS Adj. Payroll Tax	DIST_CUST	(347)	(285)	(0)	(23)	(16)	(1)	(16)	(1)	(1)	(0)	(0)	(0)	(1)	(4)
		DIST_DEMAND	(102)	(51)	(0)	(2)	(24)	(7)	(14)	(5)	(0)	(5)	(0)	(0)	(0)	(0)
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	(450)	(336)	(0)	(24)	(39)	(8)	(31)	(6)	(1)	(5)	(0)	(0)	(1)	(4)
ADJ_IS_10b	IS Adj. Other Tax	DIST_CUST	(388)	(319)	(0)	(25)	(18)	(1)	(18)	(1)	(1)	(1)	(0)	(0)	(1)	(5)
		DIST_DEMAND	(115)	(57)	(0)	(2)	(26)	(8)	(16)	(5)	(0)	(5)	(0)	(0)	(0)	(0)
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	(503)	(376)	(0)	(27)	(44)	(9)	(34)	(6)	(1)	(6)	(0)	(0)	(1)	(5)
	Total Taxes Other than Income Taxes	**DIST_CUST**	**15,771**	**12,775**	**13**	**790**	**945**	**23**	**779**	**79**	**58**	**21**	**1**	**7**	**48**	**310**
		DIST_DEMAND	**6,053**	**2,684**	**11**	**56**	**2,197**	**455**	**451**	**136**	**0**	**136**	**0**	**25**	**5**	**32**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**21,825**	**15,460**	**25**	**846**	**3,142**	**478**	**1,231**	**215**	**59**	**156**	**2**	**32**	**53**	**342**

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - INCOME TAXES
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
PRESENT RATES, $1,000s

DESCRIPTION	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
Distribution														
Distribution Revenue	191,078	154,558	180	8,434	12,730	296	8,865	1,084	866	218	16	102	610	4,204
Total Operating Expense	87,236	73,618	44	4,949	3,275	116	4,197	251	126	125	4	12	118	653
Income Before Taxes	22,465	5,557	169	(2,923)	20,259	1,195	(4,185)	(244)	407	(651)	3	298	56	2,281
Tax Deductions	40,777	29,457	29	2,065	4,119	927	3,070	469	30	439	3	30	116	491
State Taxable Income	63,242	35,013	198	(858)	24,378	2,122	(1,115)	225	437	(212)	6	329	172	2,772
Current State Income Tax	6,318	3,498	20	(86)	2,435	212	(111)	23	44	(21)	1	33	17	277
Federal Taxable Income	56,924	31,516	178	(772)	21,942	1,910	(1,004)	203	393	(190)	6	296	155	2,495
Current Federal Income Tax	19,923	11,030	62	(270)	7,680	668	(351)	71	138	(67)	2	104	54	873
Provision for Deferred Income Taxes	3,598	2,560	2	177	384	91	282	39	1	38	0	3	13	46
Investent Tax Credit Adjustments	(283)	(201)	(0)	(14)	(31)	(7)	(22)	(3)	(0)	(3)	(0)	(0)	(1)	(4)
Total Income Tax	29,556	16,888	84	(193)	10,469	964	(203)	129	182	(53)	3	139	83	1,193

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - LABOR
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
PRESENT RATES, $1,000s

ACCOUNT	DESCRIPTION		TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
580L	OP - Supv. & Engineering Labor	DIST_CUST	51	39	0	3	2	0	4	0	0	0	0	0	0	1
		DIST_DEMAND	33	19	0	1	7	2	3	1	0	1	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	84	59	0	5	9	2	7	1	0	1	0	0	0	1
581L	OP - Dispatching Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	274	127	0	4	60	18	48	15	0	15	0	0	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	274	127	0	4	60	18	48	15	0	15	0	0	0	1
582L	OP- Distribution Expense Station Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	397	184	0	5	86	27	69	22	0	22	0	1	0	1
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	397	184	0	5	86	27	69	22	0	22	0	1	0	1
583L	OP - Overhead Line Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
586L	OP - Meter Labor	DIST_CUST	561	401	1	46	47	5	47	13	13	0	0	1	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	561	401	1	46	47	5	47	13	13	0	0	1	0	0
588L	OP - Misc. Expenses	DIST_CUST	2,504	1,987	1	163	98	2	189	7	0	6	0	1	12	44
		DIST_DEMAND	1,208	645	1	19	303	93	105	33	0	33	0	2	1	5
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	3,712	2,633	3	182	401	95	293	40	0	39	0	3	14	49
590L	MN- Supv. & Engineering Labor	DIST_CUST	179	137	0	12	7	0	18	1	0	1	0	0	0	3
		DIST_DEMAND	69	34	0	1	16	5	9	3	0	3	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	248	172	0	13	23	5	28	4	0	4	0	0	0	3
591L	MN - Structures Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	8	4	0	0	2	1	1	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	8	4	0	0	2	1	1	0	0	0	0	0	0	0
592L	MN - Station Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	2,430	1,128	2	33	529	163	425	135	0	135	0	4	2	8
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,430	1,128	2	33	529	163	425	135	0	135	0	4	2	8

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - LABOR
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
PRESENT RATES, $1,000s

ACCOUNT	DESCRIPTION		TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
593L	MN - OH Conductors Labor	DIST_CUST	4,446	3,484	2	285	170	2	473	16	0	16	0	1	8	4
		DIST_DEMAND	840	451	1	13	212	65	70	22	0	22	0	2	1	3
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	5,286	3,935	3	299	382	68	543	38	0	38	0	3	8	7
595L	MN - XFMRs Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
596L	MN - Streetlights Labor	DIST_CUST	161	0	0	0	0	0	0	0	0	0	0	0	0	161
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	161	0	0	0	0	0	0	0	0	0	0	0	0	161
597L	MN - Meters Labor	DIST_CUST	1,235	884	2	102	103	11	104	29	29	0	0	1	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	1,235	884	2	102	103	11	104	29	29	0	0	1	0	0
	Labor Expense - Distribution	**DIST_CUST**	**9,137**	**6,933**	**6**	**612**	**427**	**20**	**834**	**66**	**43**	**23**	**1**	**3**	**20**	**213**
		DIST_DEMAND	**5,259**	**2,593**	**6**	**77**	**1,214**	**374**	**732**	**231**	**0**	**231**	**0**	**10**	**5**	**18**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**14,396**	**9,526**	**11**	**689**	**1,641**	**394**	**1,566**	**297**	**43**	**254**	**1**	**13**	**25**	**231**
902L	Customer Account Supervision - Labor	DIST_CUST	3,645	3,011	3	351	270	4	6	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	3,645	3,011	3	351	270	4	6	0	0	0	0	0	0	0
903L	Customer Account Collections - Labor	DIST_CUST	2,058	1,812	1	149	88	1	2	0	0	0	0	0	4	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,058	1,812	1	149	88	1	2	0	0	0	0	0	4	0
905L	Customer Account Accounts - Labor	DIST_CUST	176	155	0	13	8	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	176	155	0	13	8	0	0	0	0	0	0	0	0	0

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - LABOR
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
PRESENT RATES, $1,000s

ACCOUNT	DESCRIPTION		TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
	Labor Expense - Customer Accounts	**DIST_CUST**	**5,879**	**4,978**	**4**	**513**	**365**	**5**	**8**	**0**	**0**	**0**	**0**	**0**	**4**	**0**
		DIST_DEMAND	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**5,879**	**4,978**	**4**	**513**	**365**	**5**	**8**	**0**	**0**	**0**	**0**	**0**	**4**	**0**
907L	Customer Info Supervision Labor	DIST_CUST	271	266	0	3	2	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	271	266	0	3	2	0	0	0	0	0	0	0	0	0
908L	Customer Info Assistance Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
909L	Customer Info Advertising Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
910L	Customer Info Misc. Expense Labor	DIST_CUST	2,521	2,471	1	30	18	0	0	0	0	0	0	0	1	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	2,521	2,471	1	30	18	0	0	0	0	0	0	0	1	0
	Labor Expense - Customer Information	**DIST_CUST**	**2,792**	**2,736**	**2**	**33**	**20**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**0**
		DIST_DEMAND	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**2,792**	**2,736**	**2**	**33**	**20**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**0**
	Labor Expense - less A & G	**DIST_CUST**	**17,808**	**14,648**	**12**	**1,158**	**812**	**26**	**843**	**66**	**43**	**23**	**1**	**3**	**26**	**213**
		DIST_DEMAND	**5,259**	**2,593**	**6**	**77**	**1,214**	**374**	**732**	**231**	**0**	**231**	**0**	**10**	**5**	**18**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**23,067**	**17,241**	**17**	**1,235**	**2,026**	**400**	**1,574**	**298**	**43**	**254**	**1**	**13**	**30**	**231**
920L	A&G Salaries Labor	DIST_CUST	9	8	0	1	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	3	1	0	0	1	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	12	9	0	1	1	0	1	0	0	0	0	0	0	0

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - LABOR
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
PRESENT RATES, $1,000s

ACCOUNT	DESCRIPTION		TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
921L	A&G Office Supplies Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
922L	A&G Admin. Expenses Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
923L	A&G Outside Services Labor	DIST_CUST	3,936	3,238	3	256	179	6	186	15	10	5	0	1	6	47
		DIST_DEMAND	1,163	573	1	17	268	83	162	51	0	51	0	2	1	4
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	5,099	3,811	4	273	448	88	348	66	10	56	0	3	7	51
924L	A&G Property Insurance Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
925L	A&G Injury and Damages Labor	DIST_CUST	70	58	0	5	3	0	3	0	0	0	0	0	0	1
		DIST_DEMAND	21	10	0	0	5	1	3	1	0	1	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	91	68	0	5	8	2	6	1	0	1	0	0	0	1
926L	A&G Pension and Benefits Labor	DIST_CUST	(289)	(237)	(0)	(19)	(13)	(0)	(14)	(1)	(1)	(0)	(0)	(0)	(0)	(3)
		DIST_DEMAND	(85)	(42)	(0)	(1)	(20)	(6)	(12)	(4)	(0)	(4)	(0)	(0)	(0)	(0)
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	(374)	(280)	(0)	(20)	(33)	(6)	(26)	(5)	(1)	(4)	(0)	(0)	(0)	(4)
930_1L	A&G General Advertising Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
930_2L	A&G Misc. Expense Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
931L	A&G Rent Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - LABOR
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
PRESENT RATES, $1,000s

ACCOUNT	DESCRIPTION		TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
935L	A&G Maint. Of General Plant Labor	DIST_CUST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		DIST_ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Labor Expense - A & G	**DIST_CUST**	**3,727**	**3,066**	**2**	**242**	**170**	**5**	**176**	**14**	**9**	**5**	**0**	**1**	**5**	**45**
		DIST_DEMAND	**1,101**	**543**	**1**	**16**	**254**	**78**	**153**	**48**	**0**	**48**	**0**	**2**	**1**	**4**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**4,828**	**3,609**	**4**	**259**	**424**	**84**	**329**	**62**	**9**	**53**	**0**	**3**	**6**	**48**
	Labor Expense - Total	**DIST_CUST**	**21,535**	**17,714**	**14**	**1,401**	**982**	**31**	**1,019**	**80**	**52**	**28**	**1**	**4**	**31**	**257**
		DIST_DEMAND	**6,360**	**3,136**	**7**	**93**	**1,468**	**452**	**885**	**280**	**0**	**280**	**1**	**12**	**5**	**22**
		DIST_ENERGY	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Total	**27,895**	**20,849**	**21**	**1,494**	**2,450**	**484**	**1,904**	**360**	**52**	**308**	**2**	**16**	**37**	**279**

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
ALLOCATION METHODS

METHOD	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
Collections Expense	DIST_CUST	100.0%	88.1%	0.0%	7.3%	4.3%	0.1%	0.1%	0.0%	0.0%				0.2%	
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	88.1%	0.0%	7.3%	4.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%
Customer Accounting Expenses	DIST_CUST	100.0%	88.1%	0.0%	7.3%	4.3%	0.1%	0.1%	0.0%	0.0%				0.2%	
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	88.1%	0.0%	7.3%	4.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%
Customer Information Assistance	DIST_CUST	100.0%	100.0%												
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Customer Information Expenses	DIST_CUST	100.0%	98.0%	0.1%	1.2%	0.7%	0.0%	0.0%	0.0%	0.0%				0.0%	
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	98.0%	0.1%	1.2%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Customers - POL	DIST_CUST	100.0%												100.0%	
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Customers - Residential	DIST_CUST	100.0%	99.9%	0.1%											
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	99.9%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Customers - Secondary	DIST_CUST	100.0%	88.1%	0.0%	7.2%	4.3%	0.1%					0.0%	0.0%	0.2%	0.1%
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	88.1%	0.0%	7.2%	4.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.1%
Customers - STLT	DIST_CUST	100.0%													100.0%
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Customers - Total	DIST_CUST	100.0%	88.0%	0.0%	7.2%	4.3%	0.1%	0.1%	0.0%	0.0%		0.0%	0.0%	0.2%	0.1%
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	88.0%	0.0%	7.2%	4.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.1%

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
ALLOCATION METHODS

METHOD	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
D & G Net Plant	DIST_CUST	67.9%	54.0%	0.0%	4.4%	2.7%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.2%	1.2%
	DIST_DEMAND	32.1%	17.3%	0.0%	0.5%	8.1%	2.5%	2.6%	0.8%		0.8%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	71.3%	0.1%	4.9%	10.8%	2.5%	7.7%	1.0%	0.0%	1.0%	0.0%	0.1%	0.3%	1.3%
D & G Original Cost Plant	DIST_CUST	67.9%	54.1%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.1%	17.1%	0.0%	0.5%	8.0%	2.5%	2.8%	0.9%	0.0%	0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	71.2%	0.1%	4.9%	10.7%	2.5%	7.8%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
D Original Cost Plant, 360 Accounts	DIST_CUST	66.9%	53.8%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%		0.2%	0.0%	0.0%	0.1%	0.6%
	DIST_DEMAND	33.1%	17.6%	0.0%	0.5%	8.3%	2.5%	3.0%	0.6%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	71.4%	0.1%	4.9%	10.9%	2.6%	8.1%	0.8%	0.0%	1.1%	0.0%	0.1%	0.1%	0.7%
D Original Cost Plant, 360 OH	DIST_CUST	84.1%	65.9%	0.0%	5.4%	3.2%	0.0%	8.9%	0.3%		0.3%	0.0%	0.0%	0.1%	0.1%
	DIST_DEMAND	15.9%	8.5%	0.0%	0.3%	4.0%	1.2%	1.3%	0.4%		0.4%	0.0%	0.0%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	74.4%	0.1%	5.6%	7.2%	1.3%	10.3%	0.7%	0.0%	0.7%	0.0%	0.1%	0.2%	0.1%
D Original Cost Plant, 580 Accounts	DIST_CUST	60.3%	47.0%	0.0%	4.1%	2.9%	0.1%	4.7%	0.4%	0.3%	0.1%	0.0%	0.0%	0.2%	0.9%
	DIST_DEMAND	39.7%	22.9%	0.0%	1.4%	7.9%	2.2%	3.8%	1.2%	0.3%	0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	69.9%	0.1%	5.5%	10.8%	2.4%	8.5%	1.6%	0.5%	1.0%	0.0%	0.1%	0.3%	1.0%
D Original Cost Plant, 590 Accounts	DIST_CUST	72.2%	55.4%	0.0%	4.7%	3.0%	0.1%	7.4%	0.4%	0.1%	0.2%	0.0%	0.0%	0.1%	1.0%
	DIST_DEMAND	27.8%	13.8%	0.0%	0.4%	6.5%	2.0%	3.7%	1.2%		1.2%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	69.2%	0.1%	5.1%	9.5%	2.1%	11.2%	1.6%	0.1%	1.4%	0.0%	0.1%	0.1%	1.1%
Demand - Non-Concident Peak	DIST_CUST														
	DIST_DEMAND	100.0%	46.4%	0.1%	1.4%	21.8%	6.7%	17.5%	5.5%		5.5%	0.0%	0.2%	0.1%	0.3%
	DIST_ENERGY														
	Total	100.0%	46.4%	0.1%	1.4%	21.8%	6.7%	17.5%	5.5%	0.0%	5.5%	0.0%	0.2%	0.1%	0.3%
Deposits	DIST_CUST	100.0%	55.6%	0.1%	21.5%	12.8%	2.6%	6.8%	0.7%	0.7%			0.0%		
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	55.6%	0.1%	21.5%	12.8%	2.6%	6.8%	0.7%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%
Direct Assignment - Waverly	DIST_CUST														
	DIST_DEMAND														
	DIST_ENERGY	100.0%													
	Total	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
ALLOCATION METHODS

METHOD	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
Dist Net Plant	DIST_CUST	67.2%	53.3%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.4%	1.2%
	DIST_DEMAND	32.8%	17.4%	0.0%	0.5%	8.2%	2.5%	2.9%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.7%	0.1%	4.9%	10.8%	2.6%	8.0%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Dist Original Cost Plant	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Expense - Total A & G Less Adj.	DIST_CUST	76.6%	62.9%	0.0%	5.0%	3.5%	0.1%	3.7%	0.3%	0.2%	0.1%	0.0%	0.0%	0.1%	0.9%
	DIST_DEMAND	23.4%	11.6%	0.0%	0.3%	5.4%	1.7%	3.2%	1.0%	0.0%	1.0%	0.0%	0.0%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	74.5%	0.1%	5.3%	8.9%	1.8%	6.9%	1.3%	0.2%	1.1%	0.0%	0.1%	0.1%	1.0%
Expense - Total Less A & G	DIST_CUST	85.1%	72.6%	0.0%	4.6%	2.9%	0.1%	4.1%	0.2%	0.1%	0.1%	0.0%	0.0%	0.1%	0.5%
	DIST_DEMAND	14.9%	7.4%	0.0%	0.2%	3.5%	1.1%	1.9%	0.6%	0.0%	0.6%	0.0%	0.0%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	80.0%	0.1%	4.8%	6.4%	1.2%	6.0%	0.8%	0.1%	0.7%	0.0%	0.0%	0.1%	0.5%
Forfeited Discounts	DIST_CUST	100.0%	88.1%	0.0%	7.3%	4.3%	0.1%	0.1%	0.0%	0.0%				0.2%	
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	88.1%	0.0%	7.3%	4.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%
Gen Original Cost Plant	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Labor Expense - Customer Accounts	DIST_CUST	100.0%	84.7%	0.1%	8.7%	6.2%	0.1%	0.1%	0.0%	0.0%				0.1%	
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	84.7%	0.1%	8.7%	6.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%
Labor Expense - Customer Information	DIST_CUST	100.0%	98.0%	0.1%	1.2%	0.7%	0.0%	0.0%	0.0%	0.0%				0.0%	
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	98.0%	0.1%	1.2%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Labor Expense - Distribution	DIST_CUST	63.5%	48.2%	0.0%	4.3%	3.0%	0.1%	5.8%	0.5%	0.3%	0.2%	0.0%	0.0%	0.1%	1.5%
	DIST_DEMAND	36.5%	18.0%	0.0%	0.5%	8.4%	2.6%	5.1%	1.6%	0.0%	1.6%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	66.2%	0.1%	4.8%	11.4%	2.7%	10.9%	2.1%	0.3%	1.8%	0.0%	0.1%	0.2%	1.6%
Labor Expense - less A & G	DIST_CUST	77.2%	63.5%	0.1%	5.0%	3.5%	0.1%	3.7%	0.3%	0.2%	0.1%	0.0%	0.0%	0.1%	0.9%
	DIST_DEMAND	22.8%	11.2%	0.0%	0.3%	5.3%	1.6%	3.2%	1.0%	0.0%	1.0%	0.0%	0.0%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	74.7%	0.1%	5.4%	8.8%	1.7%	6.8%	1.3%	0.2%	1.1%	0.0%	0.1%	0.1%	1.0%
Labor Expense - Total	DIST_CUST	77.2%	63.5%	0.1%	5.0%	3.5%	0.1%	3.7%	0.3%	0.2%	0.1%	0.0%	0.0%	0.1%	0.9%
	DIST_DEMAND	22.8%	11.2%	0.0%	0.3%	5.3%	1.6%	3.2%	1.0%	0.0%	1.0%	0.0%	0.0%	0.0%	0.1%

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
ALLOCATION METHODS

METHOD	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
	DIST_ENERGY														
	Total	100.0%	74.7%	0.1%	5.4%	8.8%	1.7%	6.8%	1.3%	0.2%	1.1%	0.0%	0.1%	0.1%	1.0%
Meter Plant	DIST_CUST	100.0%	71.6%	0.1%	8.3%	8.3%	0.9%	8.4%	2.3%	2.3%		0.0%	0.1%		
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	71.6%	0.1%	8.3%	8.3%	0.9%	8.4%	2.3%	2.3%	0.0%	0.0%	0.1%	0.0%	0.0%
Meter Reading Expense	DIST_CUST	100.0%	82.6%	0.1%	9.6%	7.4%	0.1%	0.2%	0.0%	0.0%					
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	82.6%	0.1%	9.6%	7.4%	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
OH Conductors - Primary	DIST_CUST	0.1%						0.1%	0.0%		0.0%				
	DIST_DEMAND	99.9%						75.9%	24.0%		24.0%				
	DIST_ENERGY														
	Total	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	76.0%	24.0%	0.0%	24.0%	0.0%	0.0%	0.0%	0.0%
OH Conductors - Secondary	DIST_CUST	17.7%	15.6%	0.0%	1.3%	0.8%	0.0%					0.0%	0.0%	0.0%	0.0%
	DIST_DEMAND	82.3%	49.7%	0.1%	1.5%	23.3%	7.2%					0.0%	0.2%	0.1%	0.3%
	DIST_ENERGY														
	Total	100.0%	65.2%	0.1%	2.7%	24.0%	7.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.1%	0.4%
Plant - Account 302 (Intangible Plant)	DIST_CUST	67.9%	54.0%	0.0%	4.4%	2.7%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.2%	1.2%
	DIST_DEMAND	32.1%	17.3%	0.0%	0.5%	8.1%	2.5%	2.6%	0.8%		0.8%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	71.3%	0.1%	4.9%	10.8%	2.5%	7.7%	1.0%	0.0%	1.0%	0.0%	0.1%	0.3%	1.3%
Plant - Account 303 (Intangible Plant)	DIST_CUST	85.1%	72.6%	0.0%	4.6%	2.9%	0.1%	4.1%	0.2%	0.1%	0.1%	0.0%	0.0%	0.1%	0.5%
	DIST_DEMAND	14.9%	7.4%	0.0%	0.2%	3.5%	1.1%	1.9%	0.6%	0.0%	0.6%	0.0%	0.0%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	80.0%	0.1%	4.8%	6.4%	1.2%	6.0%	0.8%	0.1%	0.7%	0.0%	0.0%	0.1%	0.5%
Plant - Account 360 (Land)	DIST_CUST	66.9%	53.8%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%		0.2%	0.0%	0.0%	0.1%	0.6%
	DIST_DEMAND	33.1%	17.6%	0.0%	0.5%	8.3%	2.5%	3.0%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	71.4%	0.1%	4.9%	10.9%	2.6%	8.1%	1.1%	0.0%	1.1%	0.0%	0.1%	0.1%	0.7%
Plant - Account 361 (Structures)	DIST_CUST														
	DIST_DEMAND	100.0%	46.4%	0.1%	1.4%	21.8%	6.7%	17.5%	5.5%		5.5%	0.0%	0.2%	0.1%	0.3%
	DIST_ENERGY														
	Total	100.0%	46.4%	0.1%	1.4%	21.8%	6.7%	17.5%	5.5%	0.0%	5.5%	0.0%	0.2%	0.1%	0.3%
Plant - Account 362 (Station)	DIST_CUST														
	DIST_DEMAND	100.0%	46.4%	0.1%	1.4%	21.8%	6.7%	17.5%	5.5%		5.5%	0.0%	0.2%	0.1%	0.3%
	DIST_ENERGY														
	Total	100.0%	46.4%	0.1%	1.4%	21.8%	6.7%	17.5%	5.5%	0.0%	5.5%	0.0%	0.2%	0.1%	0.3%
Plant - Account 364 (Poles)	DIST_CUST	77.9%	61.5%	0.0%	5.0%	3.0%	0.0%	4.9%	0.2%		0.2%	0.0%	0.0%	0.1%	3.0%
	DIST_DEMAND	22.1%	11.9%	0.0%	0.4%	5.6%	1.7%	1.9%			0.6%	0.0%	0.0%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	73.4%	0.1%	5.4%	8.6%	1.8%	6.7%	0.2%	0.0%	0.8%	0.0%	0.1%	0.2%	3.1%

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
ALLOCATION METHODS

METHOD	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
Plant - Account 365 (OH Conductors)	DIST_CUST	84.1%	65.9%	0.0%	5.4%	3.2%	0.0%	8.9%	0.3%		0.3%	0.0%	0.0%	0.1%	0.1%
	DIST_DEMAND	15.9%	8.5%	0.0%	0.3%	4.0%	1.2%	1.3%			0.4%	0.0%	0.0%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	74.4%	0.1%	5.6%	7.2%	1.3%	10.3%	0.3%	0.0%	0.7%	0.0%	0.1%	0.2%	0.1%
Plant - Account 366 (UG Conduits)	DIST_CUST														
	DIST_DEMAND	100.0%	54.9%	0.1%	1.6%	25.8%	7.9%	6.8%			2.1%	0.0%	0.2%	0.1%	0.4%
	DIST_ENERGY														
	Total	100.0%	54.9%	0.1%	1.6%	25.8%	7.9%	6.8%	0.0%	0.0%	2.1%	0.0%	0.2%	0.1%	0.4%
Plant - Account 367 (UG Conductors)	DIST_CUST	88.4%	60.2%	0.0%	4.9%	2.9%	0.0%	19.4%	0.7%		0.7%	0.0%	0.0%	0.1%	0.1%
	DIST_DEMAND	11.6%	5.4%	0.0%	0.2%	2.5%	0.8%	2.0%			0.6%	0.0%	0.0%	0.0%	0.0%
	DIST_ENERGY														
	Total	100.0%	65.6%	0.0%	5.1%	5.5%	0.8%	21.4%	0.7%	0.0%	1.3%	0.0%	0.0%	0.1%	0.1%
Plant - Account 368 (Transformers)	DIST_CUST	56.7%	49.9%	0.0%	4.1%	2.4%	0.0%					0.0%	0.0%	0.1%	0.1%
	DIST_DEMAND	43.3%	26.1%	0.1%	0.8%	12.2%	3.8%					0.0%	0.1%	0.0%	0.2%
	DIST_ENERGY														
	Total	100.0%	76.0%	0.1%	4.9%	14.7%	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.2%
Plant - Account 369 (Services)	DIST_CUST	100.0%	88.1%	0.0%	7.2%	4.3%	0.1%					0.0%	0.0%	0.2%	0.1%
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	88.1%	0.0%	7.2%	4.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.1%
Plant - Account 370 (Meters)	DIST_CUST	100.0%	71.6%	0.1%	8.3%	8.3%	0.9%	8.4%	2.3%	2.3%		0.0%	0.1%		
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	71.6%	0.1%	8.3%	8.3%	0.9%	8.4%	2.3%	2.3%	0.0%	0.0%	0.1%	0.0%	0.0%
Plant - Account 371 (Cust Premises)	DIST_CUST	100.0%												100.0%	
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Plant - Account 372 (Leased Propery - Cust Prem.)	DIST_CUST														
	DIST_DEMAND														
	DIST_ENERGY														
	Total	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Plant - Account 373 (Streetlight)	DIST_CUST	100.0%													100.0%
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Plant - Account 389 (Land - Misc)	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Plant - Account 390 (Structures - Misc)	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
ALLOCATION METHODS

METHOD	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Plant - Account 391 (Office Equipment)	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Plant - Account 392 (Transportation)	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Plant - Account 393 (Stores)	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Plant - Account 394 (Tools & Garage Equipment)	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Plant - Account 395 (Laboratory)	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Plant - Account 396 (Power Equipment)	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Plant - Account 397 (Communications Equipment)	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Plant - Account 398 (Misc. Equipment)	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Expense - Account 580 (OP - Supv. & Engineering)	DIST_CUST	60.3%	47.0%	0.0%	4.1%	2.9%	0.1%	4.7%	0.4%	0.3%	0.1%	0.0%	0.0%	0.2%	0.9%
	DIST_DEMAND	39.7%	22.9%	0.0%	1.4%	7.9%	2.2%	3.8%	1.2%	0.3%	0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	69.9%	0.1%	5.5%	10.8%	2.4%	8.5%	1.6%	0.5%	1.0%	0.0%	0.1%	0.3%	1.0%
Expense - Account 581 (OP - Dispatching)	DIST_CUST														
	DIST_DEMAND	100.0%	46.4%	0.1%	1.4%	21.8%	6.7%	17.5%	5.5%		5.5%	0.0%	0.2%	0.1%	0.3%
	DIST_ENERGY														
	Total	100.0%	46.4%	0.1%	1.4%	21.8%	6.7%	17.5%	5.5%	0.0%	5.5%	0.0%	0.2%	0.1%	0.3%
Expense - Account 583 (OP - Overhead Line)	DIST_CUST	84.1%	65.9%	0.0%	5.4%	3.2%	0.0%	8.9%	0.3%		0.3%	0.0%	0.0%	0.1%	0.1%

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
ALLOCATION METHODS

METHOD	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
	DIST_DEMAND	15.9%	8.5%	0.0%	0.3%	4.0%	1.2%	1.3%	0.4%		0.4%	0.0%	0.0%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	74.4%	0.1%	5.6%	7.2%	1.3%	10.3%	0.7%	0.0%	0.7%	0.0%	0.1%	0.2%	0.1%
Expense - Account 586 (OP - Meter)	DIST_CUST	100.0%	71.6%	0.1%	8.3%	8.3%	0.9%	8.4%	2.3%	2.3%		0.0%	0.1%		
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	71.6%	0.1%	8.3%	8.3%	0.9%	8.4%	2.3%	2.3%	0.0%	0.0%	0.1%	0.0%	0.0%
Expense - Account 588 (OP - Misc. Expense)	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Expense - Account 590 (MN - Supv. & Engineering)	DIST_CUST	72.2%	55.4%	0.0%	4.7%	3.0%	0.1%	7.4%	0.4%	0.1%	0.2%	0.0%	0.0%	0.1%	1.0%
	DIST_DEMAND	27.8%	13.8%	0.0%	0.4%	6.5%	2.0%	3.7%	1.2%		1.2%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	69.2%	0.1%	5.1%	9.5%	2.1%	11.2%	1.6%	0.1%	1.4%	0.0%	0.1%	0.1%	1.1%
Expense - Account 591 (MN - Structures)	DIST_CUST														
	DIST_DEMAND	100.0%	46.4%	0.1%	1.4%	21.8%	6.7%	17.5%	5.5%		5.5%	0.0%	0.2%	0.1%	0.3%
	DIST_ENERGY														
	Total	100.0%	46.4%	0.1%	1.4%	21.8%	6.7%	17.5%	5.5%	0.0%	5.5%	0.0%	0.2%	0.1%	0.3%
Expense - Account 592 (MN - Station)	DIST_CUST														
	DIST_DEMAND	100.0%	46.4%	0.1%	1.4%	21.8%	6.7%	17.5%	5.5%		5.5%	0.0%	0.2%	0.1%	0.3%
	DIST_ENERGY														
	Total	100.0%	46.4%	0.1%	1.4%	21.8%	6.7%	17.5%	5.5%	0.0%	5.5%	0.0%	0.2%	0.1%	0.3%
Expense - Account 593 (MN - OH Conductors)	DIST_CUST	84.1%	65.9%	0.0%	5.4%	3.2%	0.0%	8.9%	0.3%		0.3%	0.0%	0.0%	0.1%	0.1%
	DIST_DEMAND	15.9%	8.5%	0.0%	0.3%	4.0%	1.2%	1.3%	0.4%		0.4%	0.0%	0.0%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	74.4%	0.1%	5.6%	7.2%	1.3%	10.3%	0.7%	0.0%	0.7%	0.0%	0.1%	0.2%	0.1%
Expense - Account 595 (MN - XFMRs)	DIST_CUST														
	DIST_DEMAND														
	DIST_ENERGY														
	Total	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Expense - Account 596 (MN - Streetlights)	DIST_CUST	100.0%													100.0%
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Expense - Account 597 (MN - Meters)	DIST_CUST	100.0%	71.6%	0.1%	8.3%	8.3%	0.9%	8.4%	2.3%	2.3%		0.0%	0.1%		
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	71.6%	0.1%	8.3%	8.3%	0.9%	8.4%	2.3%	2.3%	0.0%	0.0%	0.1%	0.0%	0.0%
Expense - Account 902 (Cust Acct Supervision)	DIST_CUST	100.0%	82.6%	0.1%	9.6%	7.4%	0.1%	0.2%	0.0%	0.0%					
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	82.6%	0.1%	9.6%	7.4%	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
ALLOCATION METHODS

METHOD	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
Expense - Account 903 (Cust Acct Collections)	DIST_CUST	100.0%	88.1%	0.0%	7.3%	4.3%	0.1%	0.1%	0.0%	0.0%				0.2%	
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	88.1%	0.0%	7.3%	4.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%
Expense - Account 905 (Cust Acct Accounts)	DIST_CUST	100.0%	88.1%	0.0%	7.3%	4.3%	0.1%	0.1%	0.0%	0.0%				0.2%	
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	88.1%	0.0%	7.3%	4.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%
Expense - Account 907 (Cust Info Supervision)	DIST_CUST	100.0%	98.0%	0.1%	1.2%	0.7%	0.0%	0.0%	0.0%	0.0%				0.0%	
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	98.0%	0.1%	1.2%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Expense - Account 908 (Cust Info Assistance)	DIST_CUST	100.0%	100.0%												
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Expense - Account 909 (Cust Info Advertising)	DIST_CUST	100.0%	88.1%	0.0%	7.2%	4.3%	0.1%					0.0%	0.0%	0.2%	0.1%
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	88.1%	0.0%	7.2%	4.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.1%
Expense - Account 910 (Cust Info Misc. Expense)	DIST_CUST	100.0%	98.0%	0.1%	1.2%	0.7%	0.0%	0.0%	0.0%	0.0%				0.0%	
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	98.0%	0.1%	1.2%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Expense - Account 935 (A&G Maint. General Plant)	DIST_CUST	67.5%	53.5%	0.0%	4.4%	2.6%	0.0%	5.1%	0.2%	0.0%	0.2%	0.0%	0.0%	0.3%	1.2%
	DIST_DEMAND	32.5%	17.4%	0.0%	0.5%	8.2%	2.5%	2.8%	0.9%		0.9%	0.0%	0.1%	0.0%	0.1%
	DIST_ENERGY														
	Total	100.0%	70.9%	0.1%	4.9%	10.8%	2.6%	7.9%	1.1%	0.0%	1.1%	0.0%	0.1%	0.4%	1.3%
Poles - Primary	DIST_CUST	0.1%						0.1%	0.0%		0.0%				
	DIST_DEMAND	99.9%						75.9%	24.0%		24.0%				
	DIST_ENERGY														
	Total	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	76.0%	24.0%	0.0%	24.0%	0.0%	0.0%	0.0%	0.0%
Poles - Secondary	DIST_CUST	17.7%	15.6%	0.0%	1.3%	0.8%	0.0%					0.0%	0.0%	0.0%	0.0%
	DIST_DEMAND	82.3%	49.7%	0.1%	1.5%	23.3%	7.2%					0.0%	0.2%	0.1%	0.3%
	DIST_ENERGY														
	Total	100.0%	65.2%	0.1%	2.7%	24.0%	7.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.1%	0.4%
Transformers	DIST_CUST	17.7%	15.6%	0.0%	1.3%	0.8%	0.0%					0.0%	0.0%	0.0%	0.0%
	DIST_DEMAND	82.3%	49.7%	0.1%	1.5%	23.3%	7.2%					0.0%	0.2%	0.1%	0.3%
	DIST_ENERGY														
	Total	100.0%	65.2%	0.1%	2.7%	24.0%	7.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.1%	0.4%
UG Conductors - Primary	DIST_CUST	0.1%						0.1%	0.0%		0.0%				
	DIST_DEMAND	99.9%						75.9%	24.0%		24.0%				

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - DETAILED ACCOUNTS
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
ALLOCATION METHODS

METHOD	DETAILED ACCOUNT	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	TP_A	TP_P	BRD	MS	POL	STLT
	DIST_ENERGY														
	Total	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	76.0%	24.0%	0.0%	24.0%	0.0%	0.0%	0.0%	0.0%
UG Conductors - Secondary	DIST_CUST	17.7%	15.6%	0.0%	1.3%	0.8%	0.0%					0.0%	0.0%	0.0%	0.0%
	DIST_DEMAND	82.3%	49.7%	0.1%	1.5%	23.3%	7.2%					0.0%	0.2%	0.1%	0.3%
	DIST_ENERGY														
	Total	100.0%	65.2%	0.1%	2.7%	24.0%	7.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.1%	0.4%
UG Conduits - Primary	DIST_CUST	0.1%						0.1%	0.0%		0.0%				
	DIST_DEMAND	99.9%						75.9%	24.0%		24.0%				
	DIST_ENERGY														
	Total	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	76.0%	24.0%	0.0%	24.0%	0.0%	0.0%	0.0%	0.0%
UG Conduits - Secondary	DIST_CUST	17.7%	15.6%	0.0%	1.3%	0.8%	0.0%					0.0%	0.0%	0.0%	0.0%
	DIST_DEMAND	82.3%	49.7%	0.1%	1.5%	23.3%	7.2%					0.0%	0.2%	0.1%	0.3%
	DIST_ENERGY														
	Total	100.0%	65.2%	0.1%	2.7%	24.0%	7.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.1%	0.4%
Uncollectibles	DIST_CUST	100.0%	88.1%	0.0%	7.3%	4.3%	0.1%	0.1%	0.0%	0.0%				0.2%	
	DIST_DEMAND														
	DIST_ENERGY														
	Total	100.0%	88.1%	0.0%	7.3%	4.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY
OVERVIEW OF ACCOUNTS

Type	Section	FERC Account	Account Description	Source of Total Dollars	Met-Ed Allocation Method	Method Description	Method Source
Rate Base	Plant in Service	301	Organization	RAD 46 Attach B p 1-2	D & G Net Plant	Allocation follows Distribution and General Net Plant	Plant in Service / Depreciation Reserve
Rate Base	Plant in Service	302	Franchise and Consents	RAD 46 Attach B p 1-2	D & G Net Plant	Allocation follows Distribution and General Net Plant	Plant in Service / Depreciation Reserve
Rate Base	Plant in Service	303	Intangible Plant	RAD 46 Attach B p 1-2	Expense - Total Less A & G	Allocation follows Total O & M Expense, less A & G expenses	O & M
Rate Base	Plant in Service	360	P - Land	RAD 46 Attach B p 1-2	D Original Cost Plant, 360 Accounts	Allocation follows Distribution Original Cost Plant, Accounts 361 to 369	Plant in Service
Rate Base	Plant in Service	361	P - Structures	RAD 46 Attach B p 1-2	Demand - Non-Concident Peak	Non-Coincident Peak Contribution to Zonal Peak (1NCP)	HES Exhibit 2, Study # 01
Rate Base	Plant in Service	362	P - Station	RAD 46 Attach B p 1-2	Demand - Non-Concident Peak	Non-Coincident Peak Contribution to Zonal Peak (1NCP)	HES Exhibit 2, Study # 01
Rate Base	Plant in Service	368	P - XFMRs	RAD 46 Attach B p 1-2	Transformers	Transformer Allocation - Uses Minimum Grid Study to assign customer and demand charges, then allocates customer charges to all customers based on count, and allocates demand charges based on the NCP	HES Exhibit 2, Study # 07 / KBS Exhibit 2 / HES Exhibit 2, Study # 01
Rate Base	Plant in Service	369	P - Services	RAD 46 Attach B p 1-2	Customers - Secondary	Allocates to customer charge, based on secondary customer counts	KMS Exhibit 2
Rate Base	Plant in Service	370	P - Meters	RAD 46 Attach B p 1-2	Meter Plant	Customer Component, All Customers - Weighted for Meter Plant Costs	HES Exhibit 2, Study # 08
Rate Base	Plant in Service	371	P - Customer Premises	RAD 46 Attach B p 1-2	Customers - POL	Direct Assignment to POL customer component	NA
Rate Base	Plant in Service	372	P - Leased Property Cust. Prem.	RAD 46 Attach B p 1-2	Customers - POL	Direct Assignment to POL customer component	NA
Rate Base	Plant in Service	373	P - Streetlight	RAD 46 Attach B p 1-2	Customers - STLT	Direct Assignment to STLT customer component	NA
Rate Base	Plant in Service	389	P - Land	RAD 46 Attach B p 1-2	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Plant in Service	390	P - Structures	RAD 46 Attach B p 1-2	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Plant in Service	391	P - Office Equipment	RAD 46 Attach B p 1-2	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Plant in Service	392	P - Transportation	RAD 46 Attach B p 1-2	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Plant in Service	393	P - Stores Equipment	RAD 46 Attach B p 1-2	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Plant in Service	394	P - Tools & Garage Equip.	RAD 46 Attach B p 1-2	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Plant in Service	395	P - Laboratory	RAD 46 Attach B p 1-2	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Plant in Service	396	P - Power Equipment	RAD 46 Attach B p 1-2	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Plant in Service	397	P - Communication Equipment	RAD 46 Attach B p 1-2	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Plant in Service	398	P - Misc. Equipment	RAD 46 Attach B p 1-2	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Plant in Service	364P	P - Primary Poles	RAD 46 Attach B p 1-2	Poles - Primary	Pole Plant Allocation (Primary) - Uses Minimum Grid and Primary / Secondary Study to assign customer and demand charges, then allocates customer charges to all customers based on count, and allocates demand charges based on the NCP	HES Exhibit 2, Study # 07 / KBS Exhibit 2 / HES Exhibit 2, Study # 01
Rate Base	Plant in Service	364S	P - Secondary Poles	RAD 46 Attach B p 1-2	Poles - Secondary	Pole Plant Allocation (Secondary) - Uses Minimum Grid and Primary / Secondary Study to assign customer and demand charges, then allocates customer charges to all customers based on count, and allocates demand charges based on the NCP	HES Exhibit 2, Study # 07 / KBS Exhibit 2 / HES Exhibit 2, Study # 01
Rate Base	Plant in Service	364Z	P - Streetlight Poles	RAD 46 Attach B p 1-2	Customers - STLT	Direct Assignment to STLT customer component	NA
Rate Base	Plant in Service	365P	P - OH Prim. Conductors	RAD 46 Attach B p 1-2	OH Conductors - Primary	Overhead Conductors Allocation (Primary) - Uses Minimum Grid and Primary / Secondary Study to assign customer and demand charges, then allocates customer charges to all customers based on count, and allocates demand charges based on the NCP	HES Exhibit 2, Study # 07 / KBS Exhibit 2 / HES Exhibit 2, Study # 01
Rate Base	Plant in Service	365S	P - OH Sec. Conductors	RAD 46 Attach B p 1-2	OH Conductors - Secondary	Overhead Conductors Allocation (Secondary) - Uses Minimum Grid and Primary / Secondary Study to assign customer and demand charges, then allocates customer charges to all customers based on count, and allocates demand charges based on the NCP	HES Exhibit 2, Study # 07 / KBS Exhibit 2 / HES Exhibit 2, Study # 01
Rate Base	Plant in Service	366P	P - U Prim. Conduit	RAD 46 Attach B p 1-2	UG Conduits - Primary	Underground Conduits Allocation (Primary) - Uses Primary / Secondary Study to assign primary portion, then allocates customer charges to all customers based on count, and allocates demand charges based on the NCP	HES Exhibit 2, Study # 07 / HES Exhibit 2, Study # 01
Rate Base	Plant in Service	366S	P - U Sec. Conduit	RAD 46 Attach B p 1-2	UG Conduits - Secondary	Underground Conduits Allocation (Secondary) - Uses Primary / Secondary Study to assign primary portion, then allocates customer charges to all customers based on count, and allocates demand charges based on the NCP	HES Exhibit 2, Study # 07 / HES Exhibit 2, Study # 01

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY
OVERVIEW OF ACCOUNTS

Type	Section	FERC Account	Account Description	Source of Total Dollars	Met-Ed Allocation Method	Method Description	Method Source
Rate Base	Plant in Service	367P	P - U Prim. Conductors	RAD 46 Attach B p 1-2	UG Conductors - Primary	Underground Conductors Allocation (Primary) - Uses Minimum Grid and Primary / Secondary Study to assign customer and demand charges, then allocates customer charges to all customers based on count, and allocates demand charges based on the NCP	HES Exhibit 2, Study # 07 / KBS Exhibit 2 / HES Exhibit 2, Study # 01
Rate Base	Plant in Service	367S	P - U Sec. Conductors	RAD 46 Attach B p 1-2	UG Conductors - Secondary	Underground Conductors Allocation (Secondary) -Uses Minimum Grid and Primary / Secondary Study to assign customer and demand charges, then allocates customer charges to all customers based on count, and allocates demand charges based on the NCPdemand charges	HES Exhibit 2, Study # 07 / KBS Exhibit 2 / HES Exhibit 2, Study # 01
Rate Base	Depreciation Reserve	108_302	AD - Franchise & Consents	RAD 46 Att B p 3	Plant - Account 302 (Intangible Plant)	Allocation follows Original Cost Plant of 302 Account	Plant in Service
Rate Base	Depreciation Reserve	108_303	AD - Intangible	RAD 46 Att B p 3	Plant - Account 303 (Intangible Plant)	Allocation follows Original Cost Plant of 303 Account	Plant in Service
Rate Base	Depreciation Reserve	108_360	AD - Land	RAD 46 Att B p 3	D Original Cost Plant, 360 Accounts	Allocation follows Distribution Original Cost Plant, Accounts 361 to 369	Plant in Service
Rate Base	Depreciation Reserve	108_361	AD - Structures	RAD 46 Att B p 3	Plant - Account 361 (Structures)	Allocation follows Original Cost Plant of 361 Account	Plant in Service
Rate Base	Depreciation Reserve	108_362	AD - Station	RAD 46 Att B p 3	Plant - Account 362 (Station)	Allocation follows Original Cost Plant of 362 Account	Plant in Service
Rate Base	Depreciation Reserve	108_364	AD - Poles	RAD 46 Att B p 3	Plant - Account 364 (Poles)	Allocation follows Original Cost Plant of 363 Account	Plant in Service
Rate Base	Depreciation Reserve	108_365	AD - Conductors	RAD 46 Att B p 3	Plant - Account 365 (OH Conductors)	Allocation follows Original Cost Plant of 365 Account	Plant in Service
Rate Base	Depreciation Reserve	108_366	AD - Underground Conduit	RAD 46 Att B p 3	Plant - Account 366 (UG Conduits)	Allocation follows Original Cost Plant of 366 Account	Plant in Service
Rate Base	Depreciation Reserve	108_367	AD - Underground Conductors	RAD 46 Att B p 3	Plant - Account 367 (UG Conductors)	Allocation follows Original Cost Plant of 367 Account	Plant in Service
Rate Base	Depreciation Reserve	108_368	AD - XFMRs	RAD 46 Att B p 3	Plant - Account 368 (Transformers)	Allocation follows Original Cost Plant of 368 Account	Plant in Service
Rate Base	Depreciation Reserve	108_369	AD - Services	RAD 46 Att B p 3	Plant - Account 369 (Services)	Allocation follows Original Cost Plant of 369 Account	Plant in Service
Rate Base	Depreciation Reserve	108_370	AD - Meters	RAD 46 Att B p 3	Plant - Account 370 (Meters)	Allocation follows Original Cost Plant of 370 Account	Plant in Service
Rate Base	Depreciation Reserve	108_371	AD - Customer Premises	RAD 46 Att B p 3	Plant - Account 371 (Cust Premises)	Allocation follows Original Cost Plant of 371 Account	Plant in Service
Rate Base	Depreciation Reserve	108_372	AD - Leased Property Cust. Prem.	RAD 46 Att B p 3	Plant - Account 372 (Leased Propery - Cust Prem.)	Allocation follows Original Cost Plant of 372 Account	Plant in Service
Rate Base	Depreciation Reserve	108_373	AD - Streetlights	RAD 46 Att B p 3	Plant - Account 373 (Streetlight)	Allocation follows Original Cost Plant of 373 Account	Plant in Service
Rate Base	Depreciation Reserve	108_389	AD - Land	RAD 46 Att B p 3	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Depreciation Reserve	108_390	AD - Structures	RAD 46 Att B p 3	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Depreciation Reserve	108_391	AD - Office Equipment	RAD 46 Att B p 3	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Depreciation Reserve	108_392	AD - Transportation	RAD 46 Att B p 3	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Depreciation Reserve	108_393	AD - Stores Equip.	RAD 46 Att B p 3	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Depreciation Reserve	108_394	AD - Tools & Garage Equip.	RAD 46 Att B p 3	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Depreciation Reserve	108_395	AD - Laboratory	RAD 46 Att B p 3	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Depreciation Reserve	108_396	AD - Power Equipment	RAD 46 Att B p 3	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Depreciation Reserve	108_397	AD - Communication Equip.	RAD 46 Att B p 3	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Depreciation Reserve	108_398	AD - Misc. Equipment	RAD 46 Att B p 3	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Rate Base Adjustments	235	Customer Deposits	RAD 01 Rate Base	Deposits	Customer Component, All Customers - Weighted for Deposits	HES Exhibit 2, Study # 03
Rate Base	Rate Base Adjustments	252	Customer Advances	RAD 01 Rate Base	Customers - Residential	Allocates to customer charge, based on residential accounts	KMS Exhibit 2
Rate Base	Rate Base Adjustments	ADJ_RB_2	RB Adj. Plant Held for Future Use	RAD 01 Rate Base	D Original Cost Plant, 360 Accounts	Allocation follows Distribution Original Cost Plant, Accounts 361 to 369	Plant in Service
Rate Base	Rate Base Adjustments	ADJ_RB_5	RB Adj. M&S	RAD 01 Rate Base	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Rate Base Adjustments	ADJ_RB_6	RB Adj. Storm Damage Normalization	RAD 01 Rate Base	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Rate Base Adjustments	ADJ_RB_7	RB Adj. Adjustment for Retired Legacy Meters	RAD 01 Rate Base	D Original Cost Plant, 360 Accounts	Allocation follows Distribution Original Cost Plant, Accounts 361 to 369	Plant in Service
Rate Base	Rate Base Adjustments	ADJ_RB_9	RB Adj. Operating Reserves	RAD 01 Rate Base	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Rate Base Adjustments	CWC	Cash Working Capital	RAD 01 Rate Base	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Rate Base Adjustments	RB_DIT_LIB	Deferred Tax - Liberalized Depreciation	RAD 01 Rate Base	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Rate Base	Rate Base Adjustments	RB_OP_RES	Operating Reserves	RAD 01 Rate Base	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Revenue	Revenue	450	OR - Forefeited Discount Revenue	Other Revenues 450-454	Forfeited Discounts	Customer Component, All Customers - Weighted for Forfeited Discounts	HES Exhibit 2, Study # 04
Revenue	Revenue	451	OR - Misc. Service Revenues	Other Revenues 450-454	Customers - Secondary	Allocates to customer charge, based on secondary customer counts	KMS Exhibit 2
Revenue	Revenue	454POLE	OR - Pole Rent	HES Exhibit 2, Study # 09	Plant - Account 364 (Poles)	Allocation follows Original Cost Plant of 363 Account	Plant in Service
Revenue	Revenue	454RENT	OR - Lease Rent	HES Exhibit 2, Study # 09	Labor Expense - Total	Allocation follows Total Labor Expense	HES Exhibit 2, Study # 05
Revenue	Revenue	456AECNITS	OR - AEC wheeling NITS	HES Exhibit 2, Study # 09	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Revenue	Revenue	456MISC	OR - Misc. Revenue	HES Exhibit 2, Study # 09	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Revenue	Revenue	456SCRAP	OR - NUG/TMI	HES Exhibit 2, Study # 09	D Original Cost Plant, 360 Accounts	Allocation follows Distribution Original Cost Plant, Accounts 361 to 369	Plant in Service
Expense	O & M Expenses	580	OP - Supv. & Engineering	RAD 55 P&L Summary	D Original Cost Plant, 580 Accounts	Allocation follows Distribution Original Cost Plant, Accounts 581 to 589	O & M

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY
OVERVIEW OF ACCOUNTS

Met-Ed

Type	Section	FERC Account	Account Description	Source of Total Dollars	Allocation Method	Method Description	Method Source
Expense	O & M Expenses	581	OP - Dispatching	RAD 55 P&L Summary	Demand - Non-Concident Peak	Non-Coincident Peak Contribution to Zonal Peak (1NCP)	HES Exhibit 2, Study # 01
Expense	O & M Expenses	582	OP - Station expenses	RAD 55 P&L Summary	Plant - Account 362 (Station)	Allocation follows Original Cost Plant of 362 Account	Plant in Service
Expense	O & M Expenses	583	OP - Overhead Line	RAD 55 P&L Summary	D Original Cost Plant, 360 OH	Allocation follows Distribution Original Cost Plant, Account 365	Plant in Service
Expense	O & M Expenses	584	OP - Underground lines expenses	RAD 55 P&L Summary	Plant - Account 367 (UG Conductors)	Allocation follows Original Cost Plant of 367 Account	Plant in Service
Expense	O & M Expenses	586	OP - Meter	RAD 55 P&L Summary	Plant - Account 370 (Meters)	Allocation follows Original Cost Plant of 370 Account	Plant in Service
Expense	O & M Expenses	588	OP - Misc. Expenses	RAD 55 P&L Summary	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Expense	O & M Expenses	589	MN - Rents	RAD 55 P&L Summary	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Expense	O & M Expenses	590	MN - Supv. & Engineering	RAD 55 P&L Summary	D Original Cost Plant, 590 Accounts	Allocation follows Distribution Original Cost Plant, Accounts 591 to 599	O & M
Expense	O & M Expenses	591	MN - Structures	RAD 55 P&L Summary	Plant - Account 361 (Structures)	Allocation follows Original Cost Plant of 361 Account	Plant in Service
Expense	O & M Expenses	592	MN - Station	RAD 55 P&L Summary	Plant - Account 362 (Station)	Allocation follows Original Cost Plant of 362 Account	Plant in Service
Expense	O & M Expenses	593	MN - OH Concuctors	RAD 55 P&L Summary	Plant - Account 365 (OH Conductors)	Allocation follows Original Cost Plant of 365 Account	Plant in Service
Expense	O & M Expenses	594	MN - UG Concuctors	RAD 55 P&L Summary	Plant - Account 367 (UG Conductors)	Allocation follows Original Cost Plant of 367 Account	Plant in Service
Expense	O & M Expenses	595	MN - XFMRs	RAD 55 P&L Summary	Plant - Account 368 (Transformers)	Allocation follows Original Cost Plant of 368 Account	Plant in Service
Expense	O & M Expenses	596	MN - Streetlights	RAD 55 P&L Summary	Plant - Account 373 (Streetlight)	Allocation follows Original Cost Plant of 373 Account	Plant in Service
Expense	O & M Expenses	597	MN - Meters	RAD 55 P&L Summary	Plant - Account 370 (Meters)	Allocation follows Original Cost Plant of 370 Account	Plant in Service
Expense	O & M Expenses	598	MN - Maintenance of miscellaneous	RAD 55 P&L Summary	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Expense	O & M Expenses	902	Customer Account Supervision	RAD 55 P&L Summary	Meter Reading Expense	Customer Component, All Customers - Weighted for Meter Reading Expense	HES Exhibit 2, Study # 04
Expense	O & M Expenses	903	Customer Account Collections	RAD 55 P&L Summary	Collections Expense	Customer Component, All Customers - Weighted for Collections Expenses	HES Exhibit 2, Study # 04
Expense	O & M Expenses	904	Customer Account Uncollectables	RAD 55 P&L Summary	Uncollectibles	Customer Component, All Customers - Weighted for Uncollectibles Expenses	HES Exhibit 2, Study # 04
Expense	O & M Expenses	905	Customer Account Accounts	RAD 55 P&L Summary	Customer Accounting Expenses	Customer Component, All Customers - Weighted for Misc. Customer Acctg Expenses	HES Exhibit 2, Study # 04
Expense	O & M Expenses	907	Customer Info Supervision	RAD 55 P&L Summary	Customer Information Expenses	Customer Component, All Customers - Weighted for Information Assistance Expenses	HES Exhibit 2, Study # 04
Expense	O & M Expenses	908	Customer Info Assistance Dist.	RAD 55 P&L Summary	Customer Information Assistance	Customer Component, All Customers - Weighted for Information Expenses	HES Exhibit 2, Study # 04
Expense	O & M Expenses	909	Customer Info Advertising Dist.	RAD 55 P&L Summary	Customers - Secondary	Allocates to customer charge, based on secondary customer counts	KMS Exhibit 2
Expense	O & M Expenses	910	Customer Info Misc. Expense	RAD 55 P&L Summary	Customer Information Expenses	Customer Component, All Customers - Weighted for Information Assistance Expenses	HES Exhibit 2, Study # 04
Expense	O & M Expenses	913	Advertising expenses	RAD 55 P&L Summary	Customers - Total	Allocates to customer charge, based on total customer counts	KMS Exhibit 2
Expense	O & M Expenses	920	A&G Salaries	RAD 55 P&L Summary	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	921	A&G Office Supplies	RAD 55 P&L Summary	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	922	A&G Admin. Expenses	RAD 55 P&L Summary	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	923	A&G Outside Services	RAD 55 P&L Summary	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	924	A&G Property Insurance	RAD 55 P&L Summary	Dist Net Plant	Allocation follows Distribution Net Plant	Plant in Service / Depreciation Reserve
Expense	O & M Expenses	925	A&G Injury and Damages	RAD 55 P&L Summary	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	926	A&G Pension and Benefits	RAD 55 P&L Summary	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	928	Regulatory Commission Expense	RAD 55 P&L Summary	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	931	A&G Misc. Rent	RAD 55 P&L Summary	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	935	A&G Maint. Of General Plant	RAD 55 P&L Summary	Gen Original Cost Plant	General Plant, Original Cost	Plant in Service
Expense	O & M Expenses	930_1	A&G General Advertising	RAD 55 P&L Summary	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	930_2	A&G Misc. Expense	RAD 55 P&L Summary	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	ADJ_IS_4a	IS Adj. Distribution Payroll	RAD 02 Income Statement	Labor Expense - Distribution	Allocation follows Distribution Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	ADJ_IS_4c	IS Adj. Distribution Reaquired Debt	RAD 02 Income Statement	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Expense	O & M Expenses	ADJ_IS_5a	IS Adj. Customer Accounts Payroll	RAD 02 Income Statement	Labor Expense - Customer Accounts	Allocation follows Customer Accounts Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	ADJ_IS_5b	IS Adj. Customer Accounts Deposits	RAD 02 Income Statement	Deposits	Customer Component, All Customers - Weighted for Deposits	HES Exhibit 2, Study # 03
Expense	O & M Expenses	ADJ_IS_5c	IS Adj. Customer Accounts Uncollectables	RAD 02 Income Statement	Customers - Residential	Allocates to customer charge, based on residential accounts	KMS Exhibit 2
Expense	O & M Expenses	ADJ_IS_5d	IS Adj. Customer Accounts No. of Cust.	RAD 02 Income Statement	Customers - Total	Allocates to customer charge, based on total customer counts	KMS Exhibit 2
Expense	O & M Expenses	ADJ_IS_6	IS Adj. Customer Service Payroll	RAD 02 Income Statement	Labor Expense - Customer Information	Allocation follows Customer Information Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	ADJ_IS_7a	IS Adj. Cash Pension	RAD 02 Income Statement	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	ADJ_IS_7b	IS Adj. Other Employee Benefit Costs	RAD 02 Income Statement	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	ADJ_IS_7c	IS Adj. A&G Non-Juris. Expense	RAD 02 Income Statement	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Expense	O & M Expenses	ADJ_IS_7d	IS Adj. A&G Rate Case Expense	RAD 02 Income Statement	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY
OVERVIEW OF ACCOUNTS

Met-Ed

Type	Section	FERC Account	Account Description	Source of Total Dollars	Allocation Method	Method Description	Method Source
Expense	O & M Expenses	ADJ_IS_7e	IS Adj. A&G Legacy Meters	RAD 02 Income Statement	Customers - Total	Allocates to customer charge, based on total customer counts	KMS Exhibit 2
Expense	O & M Expenses	ADJ_IS_7e	IS Adj. A&G Accelerated Switching Expense	RAD 02 Income Statement	Customers - Total	Allocates to customer charge, based on total customer counts	KMS Exhibit 2
Expense	O & M Expenses	ADJ_IS_7f	IS Adj. Accelerated Switching	RAD 02 Income Statement	Expense - Total A & G Less Adj.	Allocation follows Total O & M Expense, less adjustments to O & M	O & M
Other Expense	Depreciation & Amortization	403_303	DE - Intangible	RAD 53 Attach A	Plant - Account 303 (Intangible Plant)	Allocation follows Original Cost Plant of 303 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_360	DE - Land	RAD 53 Attach A	Plant - Account 360 (Land)	Allocation follows Original Cost Plant of 360 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_361	DE - Structures	RAD 53 Attach A	Plant - Account 361 (Structures)	Allocation follows Original Cost Plant of 361 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_362	DE - Station	RAD 53 Attach A	Plant - Account 362 (Station)	Allocation follows Original Cost Plant of 362 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_364	DE - Poles	RAD 53 Attach A	Plant - Account 364 (Poles)	Allocation follows Original Cost Plant of 363 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_365	DE - OH Conductors	RAD 53 Attach A	Plant - Account 365 (OH Conductors)	Allocation follows Original Cost Plant of 365 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_366	DE - Underground Conduit	RAD 53 Attach A	Plant - Account 366 (UG Conduits)	Allocation follows Original Cost Plant of 366 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_367	DE - Underground Conductors	RAD 53 Attach A	Plant - Account 367 (UG Conductors)	Allocation follows Original Cost Plant of 367 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_368	DE - XFMRs	RAD 53 Attach A	Plant - Account 368 (Transformers)	Allocation follows Original Cost Plant of 368 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_369	DE - Services	RAD 53 Attach A	Plant - Account 369 (Services)	Allocation follows Original Cost Plant of 369 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_370	DE - Meters	RAD 53 Attach A	Plant - Account 370 (Meters)	Allocation follows Original Cost Plant of 370 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_371	DE - Customer Premises	RAD 53 Attach A	Plant - Account 371 (Cust Premises)	Allocation follows Original Cost Plant of 371 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_372	DE - Leased Property Cust. Prem.	RAD 53 Attach A	Plant - Account 372 (Leased Propery - Cust Prem.)	Allocation follows Original Cost Plant of 372 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_373	DE - Streetlight	RAD 53 Attach A	Plant - Account 373 (Streetlight)	Allocation follows Original Cost Plant of 373 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_389	DE - Land	RAD 53 Attach A	Plant - Account 389 (Land - Misc)	Allocation follows Original Cost Plant of 389 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_390	DE - Structures	RAD 53 Attach A	Plant - Account 390 (Structures - Misc)	Allocation follows Original Cost Plant of 390 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_391	DE - Office Equipment	RAD 53 Attach A	Plant - Account 391 (Office Equipment)	Allocation follows Original Cost Plant of 391 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_392	DE - Transportation	RAD 53 Attach A	Plant - Account 392 (Transportation)	Allocation follows Original Cost Plant of 392 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_393	DE - Stores Equipment	RAD 53 Attach A	Plant - Account 393 (Stores)	Allocation follows Original Cost Plant of 393 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_394	DE - Tools & Garage Equip.	RAD 53 Attach A	Plant - Account 394 (Tools & Garage Equipment)	Allocation follows Original Cost Plant of 394 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_395	DE - Laboratory	RAD 53 Attach A	Plant - Account 395 (Laboratory)	Allocation follows Original Cost Plant of 395 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_396	DE - Power Equipment	RAD 53 Attach A	Plant - Account 396 (Power Equipment)	Allocation follows Original Cost Plant of 396 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_397	DE - Communications Equipment	RAD 53 Attach A	Plant - Account 397 (Communications Equipment)	Allocation follows Original Cost Plant of 397 Account	Plant in Service
Other Expense	Depreciation & Amortization	403_398	DE - Misc. Equipment	RAD 53 Attach A	Plant - Account 398 (Misc. Equipment)	Allocation follows Original Cost Plant of 398 Account	Plant in Service
Other Expense	Depreciation & Amortization	404_5	Amortization and depletion of utility plant	RAD 55 P&L Summary	D & G Original Cost Plant	Allocation follows Distribution and General Original Cost Plant	Plant in Service
Other Expense	Depreciation & Amortization	407_Dist	Amortization - Rate Case Expense	Amortization UIP	Customers - Total	Allocates to customer charge, based on total customer counts	KMS Exhibit 2
Other Expense	Depreciation & Amortization	407_SMIP	Amortization - SMIP Legacy Meters	Amortization UIP	Meter Plant	Customer Component, All Customers - Weighted for Meter Plant Costs	HES Exhibit 2, Study # 08
Other Expense	Depreciation & Amortization	407_SMT	Amortization - Smart Meter	Amortization UIP	Meter Plant	Customer Component, All Customers - Weighted for Meter Plant Costs	HES Exhibit 2, Study # 08
Other Expense	Depreciation & Amortization	407_WAV	Amortization - Waverly	Amortization UIP	Direct Assignment - Waverly	Direct Assignment to Waverly customer component	NA
Other Expense	Depreciation & Amortization	411_1	Accretion expense	RAD 55 P&L Summary	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Other Expense	Depreciation & Amortization	ADJ_IS_8a	IS Adj - Cost of Removal/Salvage	RAD 02 Income Statement	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Other Expense	Depreciation & Amortization	ADJ_IS_8c	IS Adj - Average net Salvage	RAD 02 Income Statement	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Other Expense	Depreciation & Amortization	ADJ_IS_8d	IS Adj - DE Accelerated Dep. Legacy Meters	RAD 02 Income Statement	Meter Plant	Customer Component, All Customers - Weighted for Meter Plant Costs	HES Exhibit 2, Study # 08
Other Expense	Depreciation & Amortization	ADJ_IS_9	IS Adj - Amortization Expense	RAD 02 Income Statement	Dist Original Cost Plant	Allocation Follows Distribution Original Cost Plant	Plant in Service
Other Expense	Taxes other than Income	408_1CAP	OT - Capital Stock Tax	RAD 32 Tax OTI	D & G Original Cost Plant	Allocation follows Distribution and General Original Cost Plant	Plant in Service
Other Expense	Taxes other than Income	408_1LND	OT - Property Tax	RAD 32 Tax OTI	D & G Original Cost Plant	Allocation follows Distribution and General Original Cost Plant	Plant in Service
Other Expense	Taxes other than Income	408_1MISC	OT - Misc. Tax	RAD 32 Tax OTI	D & G Original Cost Plant	Allocation follows Distribution and General Original Cost Plant	Plant in Service
Other Expense	Taxes other than Income	408_1PAY	OT - Payroll Tax	RAD 32 Tax OTI	Labor Expense - Total	Allocation follows Total Labor Expense	HES Exhibit 2, Study # 05
Other Expense	Taxes other than Income	ADJ_IS_10a	IS Adj. Payroll Tax	RAD 02 Income Statement	Labor Expense - Total	Allocation follows Total Labor Expense	HES Exhibit 2, Study # 05
Other Expense	Taxes other than Income	ADJ_IS_10b	IS Adj. Other Tax	RAD 02 Income Statement	Labor Expense - Total	Allocation follows Total Labor Expense	HES Exhibit 2, Study # 05
Labor	Labor	580L	OP - Supv. & Engineering Labor	HES Exhibit 2, Study # 05	Expense - Account 580 (OP - Supv. & Engineering)	Allocation follows O & M Expense of 580 Account	O & M
Labor	Labor	581L	OP - Dispatching Labor	HES Exhibit 2, Study # 05	Expense - Account 581 (OP - Dispatching)	Allocation follows O & M Expense of 581 Account	O & M
Labor	Labor	582L	OP- Distribution Expense Station Labor	HES Exhibit 2, Study # 05	Plant - Account 362 (Station)	Allocation follows Original Cost Plant of 362 Account	Plant in Service

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY
OVERVIEW OF ACCOUNTS

Type	Section	FERC Account	Account Description	Source of Total Dollars	Met-Ed Allocation Method	Method Description	Method Source
Labor	Labor	583L	OP - Overhead Line Labor	HES Exhibit 2, Study # 05	Expense - Account 583 (OP - Overhead Line)	Allocation follows O & M Expense of 583 Account	O & M
Labor	Labor	586L	OP - Meter Labor	HES Exhibit 2, Study # 05	Expense - Account 586 (OP - Meter)	Allocation follows O & M Expense of 586 Account	O & M
Labor	Labor	588L	OP - Misc. Expenses	HES Exhibit 2, Study # 05	Expense - Account 588 (OP - Misc. Expense)	Allocation follows O & M Expense of 588 Account	O & M
Labor	Labor	590L	MN- Supv. & Engineering Labor	HES Exhibit 2, Study # 05	Expense - Account 590 (MN - Supv. & Engineering)	Allocation follows O & M Expense of 590 Account	O & M
Labor	Labor	591L	MN - Structures Labor	HES Exhibit 2, Study # 05	Expense - Account 591 (MN - Structures)	Allocation follows O & M Expense of 591 Account	O & M
Labor	Labor	592L	MN - Station Labor	HES Exhibit 2, Study # 05	Expense - Account 592 (MN - Station)	Allocation follows O & M Expense of 592 Account	O & M
Labor	Labor	593L	MN - OH Conductors Labor	HES Exhibit 2, Study # 05	Expense - Account 593 (MN - OH Conductors)	Allocation follows O & M Expense of 593 Account	O & M
Labor	Labor	595L	MN - XFMRs Labor	HES Exhibit 2, Study # 05	Expense - Account 595 (MN - XFMRs)	Allocation follows O & M Expense of 595 Account	O & M
Labor	Labor	596L	MN - Streetlights Labor	HES Exhibit 2, Study # 05	Expense - Account 596 (MN - Streetlights)	Allocation follows O & M Expense of 596 Account	O & M
Labor	Labor	597L	MN - Meters Labor	HES Exhibit 2, Study # 05	Expense - Account 597 (MN - Meters)	Allocation follows O & M Expense of 597 Account	O & M
Labor	Labor	902L	Customer Account Supervision - Labor	HES Exhibit 2, Study # 05	Expense - Account 902 (Cust Acct Supervision)	Allocation follows O & M Expense of 902 Account	O & M
Labor	Labor	903L	Customer Account Collections - Labor	HES Exhibit 2, Study # 05	Expense - Account 903 (Cust Acct Collections)	Allocation follows O & M Expense of 903 Account	O & M
Labor	Labor	905L	Customer Account Accounts - Labor	HES Exhibit 2, Study # 05	Expense - Account 905 (Cust Acct Accounts)	Allocation follows O & M Expense of 905 Account	O & M
Labor	Labor	907L	Customer Info Supervision Labor	HES Exhibit 2, Study # 05	Expense - Account 907 (Cust Info Supervision)	Allocation follows O & M Expense of 907Account	O & M
Labor	Labor	908L	Customer Info Assistance Labor	HES Exhibit 2, Study # 05	Expense - Account 908 (Cust Info Assistance)	Allocation follows O & M Expense of 908 Account	O & M
Labor	Labor	909L	Customer Info Advertising Labor	HES Exhibit 2, Study # 05	Expense - Account 909 (Cust Info Advertising)	Allocation follows O & M Expense of 909 Account	O & M
Labor	Labor	910L	Customer Info Misc. Expense Labor	HES Exhibit 2, Study # 05	Expense - Account 910 (Cust Info Misc. Expense)	Allocation follows O & M Expense of 901 Account	O & M
Labor	Labor	920L	A&G Salaries Labor	HES Exhibit 2, Study # 05	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Labor	Labor	921L	A&G Office Supplies Labor	HES Exhibit 2, Study # 05	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Labor	Labor	922L	A&G Admin. Expenses Labor	HES Exhibit 2, Study # 05	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Labor	Labor	923L	A&G Outside Services Labor	HES Exhibit 2, Study # 05	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Labor	Labor	924L	A&G Property Insurance Labor	HES Exhibit 2, Study # 05	Dist Net Plant	Allocation follows Distribution Net Plant	Plant in Service / Depreciation Reserve
Labor	Labor	925L	A&G Injury and Damages Labor	HES Exhibit 2, Study # 05	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Labor	Labor	926L	A&G Pension and Benefits Labor	HES Exhibit 2, Study # 05	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Labor	Labor	930_1L	A&G General Advertising Labor	HES Exhibit 2, Study # 05	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Labor	Labor	930_2L	A&G Misc. Expense Labor	HES Exhibit 2, Study # 05	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Labor	Labor	931L	A&G Rent Labor	HES Exhibit 2, Study # 05	Labor Expense - less A & G	Allocation follows Labor Expense, Less A&G Labor Expense	HES Exhibit 2, Study # 05
Labor	Labor	935L	A&G Maint. Of General Plant Labor	HES Exhibit 2, Study # 05	Expense - Account 935 (A&G Maint. General Plant)	Allocation follows O & M Expense of 935 Account	O & M

Total - Summary

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - TOTAL SUMMARY
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
PROPOSED RATES, $1,000s

	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	BRD	MS	POL	STLT
RATE BASE												
Plant in Service	2,265,855	1,612,628	1,521	111,200	241,923	57,068	177,827	24,250	198	1,837	8,146	29,257
Depreciation Reserve	751,301	530,752	499	36,317	79,845	18,913	61,713	9,006	64	605	4,011	9,575
Net Plant	1,514,554	1,081,875	1,022	74,884	162,077	38,155	116,113	15,244	134	1,232	4,135	19,682
Rate Base Additions	281,079	199,600	190	13,810	30,387	7,198	22,305	3,051	25	231	911	3,370
Rate Base Deductions	382,669	268,196	261	22,261	41,728	9,782	29,989	4,047	32	301	1,324	4,746
Rate Base Other Total	(101,589)	(68,596)	(72)	(8,450)	(11,341)	(2,584)	(7,684)	(996)	(7)	(70)	(413)	(1,376)
Rate Base Total	1,412,965	1,013,279	950	66,434	150,737	35,571	108,429	14,248	126	1,162	3,722	18,306
INCOME STATEMENT												
Revenue												
Tariff Revenue Total	418,988	299,860	589	14,371	58,268	9,216	26,236	3,676	35	777	896	5,065
Other Revenue Total	18,593	14,476	11	1,095	1,385	238	913	131	1	9	30	304
Retail Total	437,581	314,336	600	15,467	59,652	9,454	27,148	3,807	36	786	926	5,369
Expenses												
Total Operation & Maintenance Expense	105,570	82,757	64	5,220	7,556	1,435	6,619	1,017	5	48	134	716
Depreciation Expense	76,168	54,812	58	4,122	7,470	1,607	6,001	920	7	60	277	834
Other Expenses Amortization Expense Total	22,089	15,539	15	1,071	2,431	581	1,804	247	2	19	82	298
Taxes Other than Income Taxes Excl GRT	6,110	4,482	4	317	581	125	441	74	0	4	13	68
Gross Receipts Tax	24,720	17,692	35	848	3,438	544	1,548	217	2	46	53	299
Total Operating Expense	234,658	175,282	176	11,578	21,475	4,292	16,412	2,474	17	177	559	2,215
Income Before Taxes	202,923	139,054	424	3,889	38,177	5,162	10,736	1,333	19	609	367	3,154
Income taxes												
Current State Income Tax	20,667	14,196	43	422	3,833	516	1,097	143	2	61	39	317
Current Federal Income Tax	65,174	44,768	135	1,330	12,087	1,626	3,459	451	6	192	122	998
Provision for Deferred Income Taxes	3,598	2,560	2	177	384	91	282	39	0	3	13	46
Investent Tax Credit Adjustments	(283)	(201)	(0)	(14)	(31)	(7)	(22)	(3)	(0)	(0)	(1)	(4)
Total Income Tax	89,156	61,324	180	1,915	16,274	2,225	4,816	629	8	255	172	1,357
Net Income After Tax	113,768	77,730	244	1,974	21,903	2,937	5,920	704	11	354	195	1,797
Rate of Return	8.05%	7.67%	25.68%	2.97%	14.53%	8.26%	5.46%	4.94%	8.48%	30.43%	5.23%	9.81%

METROPOLITAN EDISON COMPANY
COST OF SERVICE STUDY - TOTAL SUMMARY
FULLY FUTURE TEST YEAR
COMPANY PREFERRED ALLOCATION METHOD
EQUAL RATES, $1,000s

	TOTAL RETAIL	RS	GSV	GSS	GSM	GSL	GP	TP	BRD	MS	POL	STLT
RATE BASE												
Plant in Service	2,265,855	1,612,628	1,521	111,200	241,923	57,068	177,827	24,250	198	1,837	8,146	29,257
Depreciation Reserve	751,301	530,752	499	36,317	79,845	18,913	61,713	9,006	64	605	4,011	9,575
Net Plant	1,514,554	1,081,875	1,022	74,884	162,077	38,155	116,113	15,244	134	1,232	4,135	19,682
Rate Base Additions	281,079	199,600	190	13,810	30,387	7,198	22,305	3,051	25	231	911	3,370
Rate Base Deductions	382,669	268,196	261	22,261	41,728	9,782	29,989	4,047	32	301	1,324	4,746
Rate Base Other Total	(101,589)	(68,596)	(72)	(8,450)	(11,341)	(2,584)	(7,684)	(996)	(7)	(70)	(413)	(1,376)
Rate Base Total	1,412,965	1,013,279	950	66,434	150,737	35,571	108,429	14,248	126	1,162	3,722	18,306
INCOME STATEMENT												
Revenue												
Tariff Revenue Total	418,988	306,865	284	20,501	40,528	9,084	31,341	4,481	34	304	1,087	4,479
Other Revenue Total	18,593	14,476	11	1,095	1,385	238	913	131	1	9	30	304
Retail Total	437,581	321,341	296	21,597	41,913	9,322	32,253	4,613	35	313	1,116	4,783
Expenses												
Total Operation & Maintenance Expense	105,570	82,757	64	5,220	7,556	1,435	6,619	1,017	5	48	134	716
Depreciation Expense	76,168	54,812	58	4,122	7,470	1,607	6,001	920	7	60	277	834
Other Expenses Amortization Expense Total	22,089	15,539	15	1,071	2,431	581	1,804	247	2	19	82	298
Taxes Other than Income Taxes Excl GRT	6,110	4,482	4	317	581	125	441	74	0	4	13	68
Gross Receipts Tax	24,720	18,105	17	1,210	2,391	536	1,849	264	2	18	64	264
Total Operating Expense	234,658	175,695	158	11,940	20,429	4,284	16,714	2,522	17	149	570	2,180
Income Before Taxes	202,923	145,646	137	9,657	21,484	5,038	15,540	2,091	18	164	546	2,602
Income taxes												
Current State Income Tax	20,667	14,855	14	998	2,165	503	1,577	219	2	16	57	261
Current Federal Income Tax	65,174	46,845	44	3,148	6,828	1,587	4,973	690	6	52	178	824
Provision for Deferred Income Taxes	3,598	2,560	2	177	384	91	282	39	0	3	13	46
Investent Tax Credit Adjustments	(283)	(201)	(0)	(14)	(31)	(7)	(22)	(3)	(0)	(0)	(1)	(4)
Total Income Tax	89,156	64,059	61	4,308	9,347	2,174	6,809	944	8	71	247	1,128
Net Income After Tax	113,768	81,587	77	5,349	12,137	2,864	8,730	1,147	10	94	300	1,474
Rate of Return	8.05%	8.05%	8.05%	8.05%	8.05%	8.05%	8.05%	8.05%	8.05%	8.05%	8.05%	8.05%

Met-Ed / Penelec / Penn Power / West Penn Power
Exhibit HES – 2
Witness: H. E. Stewart

Cost of Service
Supporting Studies

Exhibit HES – 2
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Exhibit HES-2
Supporting Study No. 1
Demand Allocators

Metropolitan Edison
Coincident Peak Demands

Date	Hour	ME_BRD	ME_GP	ME_GSL	ME_GSM	ME_GSS	ME_GSV	ME_MS	ME_OL	ME_RS	ME_RT	ME_STLT	ME_TP_PRIM	ME_TP_Trans
4/4/2013	8	100	396,175	140,216	356,560	26,525	1,479	4,767	202	714,797	165,316	11	155,707	105,147
5/31/2013	16	116	434,068	165,053	587,701	25,249	2,614	3,775	292	917,880	68,469	7	144,311	97,466
6/24/2013	15	133	450,762	167,961	605,726	12,113	2,759	3,376	308	1,001,313	100,201	9	127,525	98,815
7/18/2013	18	169	463,934	164,571	611,702	37,565	2,937	3,284	311	1,259,098	120,137	9	127,095	109,186
8/27/2013	18	142	447,259	158,739	544,614	28,316	2,405	2,889	254	955,296	95,417	11	145,899	107,759
9/11/2013	14	143	448,296	180,221	682,437	23,544	3,273	4,034	346	1,057,339	56,917	16	136,697	95,738
10/4/2013	17	102	382,274	139,821	485,680	10,581	2,215	2,978	226	653,198	66,068	7	127,409	96,442
11/25/2013	19	104	340,603	114,314	353,195	25,408	1,551	2,001	1,516	1,000,160	130,418	6,093	104,576	86,061
12/12/2013	19	143	395,239	128,737	382,470	26,810	1,764	2,359	1,647	1,127,103	171,889	6,088	136,591	102,159
1/7/2014	19	135	400,745	131,467	435,001	29,731	1,969	2,609	1,752	1,244,253	205,730	6,353	116,012	101,242
2/12/2014	8	101	430,073	152,231	443,883	33,180	1,909	2,795	29	983,978	222,826	2	155,208	105,785
3/4/2014	8	165	430,581	147,742	481,837	35,873	2,035	3,022	24	875,085	198,569	2	141,904	108,161

Metropolitan Edison
Non-coincident Peak Demands

Year	Month	ME_BRD	ME_GP	ME_GSL	ME_GSM	ME_GSS	ME_GSV	ME_MS	ME_OL	ME_RS	ME_RT	ME_STLT	ME_TP	ME_TP_TRANS	ME_TP_PRIM
2013	4	166	463,406	163,284	538,875	35,225	2,353	3,377	1,844	1,246,112	247,428	7,141	276,386	111,668	167,114
2013	5	189	435,912	155,118	508,691	42,167	2,210	3,126	1,809	1,056,000	231,160	7,533	260,993	108,152	153,740
2013	6	251	446,904	157,018	541,614	46,184	2,327	3,480	2,013	1,058,265	226,376	8,689	266,412	113,965	157,516
2013	7	133	425,962	155,988	457,021	30,601	1,964	6,052	2,159	799,688	165,396	8,999	279,176	119,299	161,742
2013	8	123	484,537	187,712	603,336	32,323	2,649	5,901	2,509	1,024,596	111,116	10,501	282,210	114,099	172,039
2013	9	148	520,256	183,534	605,726	30,652	2,759	3,630	2,488	1,067,036	126,676	10,458	276,910	122,125	163,295
2013	10	193	542,785	200,879	685,799	37,565	3,189	3,782	2,748	1,317,001	133,615	10,941	283,245	121,953	170,668
2013	11	165	486,427	186,191	575,545	32,655	2,593	3,468	2,399	979,388	110,500	10,086	276,554	117,250	164,867
2013	12	192	589,917	226,147	733,777	40,183	3,375	4,515	2,457	1,073,024	159,353	10,132	303,841	127,610	177,489
2014	1	112	461,380	172,618	507,948	30,911	2,321	3,415	1,916	872,450	128,637	7,889	276,256	111,964	186,639
2014	2	144	440,254	156,242	467,858	36,482	1,935	2,894	1,815	1,048,406	169,391	7,400	271,876	122,055	163,570
2014	3	204	479,304	169,171	494,152	44,069	2,142	3,145	1,901	1,205,156	216,661	7,353	284,944	114,260	172,586
	NCP	251	589,917	226,147	733,777	46,184	3,375	6,052	2,748	1,317,001	247,428	10,941	303,841	127,610	186,639

Metropolitan Edison Company
Demand Allocators

	kWh	Average Demand	Non-Coincident Peak Demand	Excess Demand	Excess Adjusted to Peak	Coincident Peak Demand	Average & Excess
	(1)	(2) = (1)/8760	(3)	(4) = (3) - (2)	(5)	(6)	(7) =(2)+(5)
ME_RS	4,609,406,893	526,188	1,317,001	790,813	536,907	1,259,098	1,063,095
ME_RT	668,224,288	76,281	247,428	171,146	116,196	120,137	192,478
ME_GSV	11,301,578	1,290	3,375	2,085	1,416	2,937	2,706
ME_GSS	181,032,482	20,666	46,184	25,519	17,325	37,565	37,991
ME_GSM	2,608,557,954	297,781	733,777	435,997	296,011	611,702	593,792
ME_GSL	889,925,658	101,590	226,147	124,558	84,566	164,571	186,156
ME_GP	2,728,495,248	311,472	589,917	278,445	189,044	463,934	500,517
ME_MS	17,173,751	1,960	6,052	4,091	2,778	3,284	4,738
ME_TP	1,696,923,154	193,713	303,841	110,129	74,770	236,281	268,482
ME_TP_PRIM	994,435,462	113,520	186,639	73,119	49,643	127,095	163,163
ME_TP_TRAN	702,487,692	80,193	127,610	47,417	32,193	109,186	112,386
ME_BRD	858,225	98	251	153	104	169	202
ME_POL	5,870,117	670	2,748	2,078	1,411	311	2,081
ME_STLT	29,123,813	3,325	10,941	7,616	5,171	9	8,496

Pennsylvantia Electric Company
Coincident Peak Demands

Date	Hour	PN_BRD	PN_GSL	PN_GSM	PN_GSS	PN_GSV	PN_H	PN_POL	PN_RS	PN_RT	PN_STLT	PN_GP	PN_LP_PRIM	PN_LP_TRAN
4/4/2013	0700	60	187,667	502,333	44,004	3,008	7,555	411	597,052	70,059	11	333,740	378,743	14,788
5/31/2013	1500	45	189,428	674,751	43,394	2,966	4,150	560	619,784	26,511	21	292,635	295,865	29,301
6/24/2013	1300	53	216,799	685,170	46,007	3,507	3,209	533	697,863	32,866	17	341,442	362,518	33,649
7/18/2013	1300	51	236,196	712,840	50,840	4,073	3,426	561	878,030	36,136	17	369,490	340,669	30,459
8/27/2013	1300	47	233,344	665,441	48,103	3,383	4,221	563	602,664	28,870	17	370,051	315,939	22,791
9/11/2013	1300	87	278,116	745,896	52,292	3,560	5,285	421	499,260	23,245	19	434,969	342,402	34,473
10/28/2013	0800	61	172,226	465,795	33,779	2,285	5,990	284	560,859	44,861	13	288,776	313,232	28,242
11/25/2013	0900	58	177,781	592,178	47,406	3,015	8,795	378	623,398	45,726	16	299,329	339,484	17,025
12/12/2013	1900	64	155,090	462,754	44,570	2,816	5,745	4,009	970,576	62,064	7,316	284,363	291,665	28,213
1/7/2014	1900	112	152,423	519,607	52,358	3,205	7,536	4,048	1,077,974	82,546	7,666	263,966	274,313	26,253
2/12/2014	0800	77	184,860	558,074	47,340	2,620	10,407	46	830,511	80,949	0	319,150	356,299	25,997
3/4/2014	0800	141	181,610	624,837	56,457	2,977	10,297	62	727,621	66,295	0	312,778	300,811	23,277

Date	Hour	WV_BRD	WV_GS	WV_POL	WV_RS	WV_RT	WV_STLT	WV_GP
4/4/2013	0700	1	3,451	2	3,951	744	0	621
5/31/2013	1500	0	4,977	3	4,176	400	0	606
6/24/2013	1300	45	5,135	2	4,595	426	0	871
7/18/2013	1300	12	4,776	2	5,526	440	0	210
8/27/2013	1300	47	4,384	2	4,075	372	0	753
9/11/2013	1300	56	5,410	3	3,561	412	0	346
10/28/2013	0800	48	3,370	2	3,495	405	0	721
11/25/2013	0900	33	3,999	2	4,037	467	0	652
12/12/2013	1900	37	2,595	16	7,419	1,002	35	127
1/7/2014	1900	59	3,063	17	7,783	1,213	36	705
2/12/2014	0800	0	3,909	0	6,201	964	0	753
3/4/2014	0800	79	4,651	0	5,135	936	0	804

Pennsylvantia Electric Company
Non-Coincident Peak Demands

Year	Month	PN_BRD	PN_GP	PN_GSL	PN_GSM	PN_GSS	PN_GSV	PN_H	PN_POL	PN_LP	PN_LP_PRIM	PN_LP_TRAN	PN_RS	PN_RT	PN_STLT
2013	4	158	348,963	206,552	713,894	82,056	5,584	11,389	4,801	420,956	389,866	35,580	1,087,983	110,545	9,521
2013	5	90	344,377	199,521	665,689	61,687	3,456	11,508	4,969	407,356	379,953	30,838	995,075	103,264	9,821
2013	6	162	347,598	196,925	684,685	64,803	4,191	11,332	5,743	426,108	406,655	29,080	981,904	115,182	10,943
2013	7	70	333,740	187,667	601,738	51,237	3,837	8,221	5,846	464,577	445,707	34,051	796,274	79,026	11,954
2013	8	61	362,281	225,746	699,159	44,674	3,251	5,607	6,405	453,543	431,424	34,881	802,713	61,488	13,839
2013	9	70	348,458	216,799	706,060	48,727	4,345	3,943	6,706	470,250	436,000	37,399	850,141	46,223	13,376
2013	10	81	391,631	251,019	783,456	55,779	4,737	3,802	7,155	496,775	465,795	38,487	989,916	49,122	13,603
2013	11	63	382,422	233,344	676,322	50,437	3,607	4,239	7,023	405,915	376,611	35,640	740,788	43,740	12,916
2013	12	200	434,969	278,116	787,879	53,171	4,480	5,486	6,197	441,219	409,567	39,242	939,121	55,273	12,048
2014	1	83	331,972	202,740	578,623	42,520	3,325	6,201	5,049	416,513	385,294	36,221	753,576	59,403	10,398
2014	2	75	323,632	187,305	620,471	50,946	3,527	8,977	4,791	400,284	376,074	27,283	916,333	83,301	9,879
2014	3	114	338,247	195,994	633,569	54,110	3,263	9,466	4,570	433,181	403,854	33,993	982,855	95,629	8,627
	NCP	200	434,969	278,116	787,879	82,056	5,584	11,508	7,155	496,775	465,795	39,242	1,087,983	115,182	13,839

Year	Month	WV_BRD	WV_GP	WV_GS	WV_POL	WV_RS	WV_RT	WV_STLT
2013	4	95	977	4,696	20	8,015	1,213	45
2013	5	80	952	4,537	23	7,802	1,325	46
2013	6	83	925	4,792	26	7,803	1,403	52
2013	7	45	880	4,522	24	6,086	865	56
2013	8	55	953	5,070	27	5,727	654	65
2013	9	61	922	5,495	29	6,947	641	63
2013	10	53	975	5,392	29	6,690	647	64
2013	11	56	830	4,793	29	5,405	782	61
2013	12	148	865	5,911	26	6,755	693	57
2014	1	55	917	4,174	20	5,034	636	49
2014	2	52	917	4,295	19	6,154	943	47
2014	3	63	862	3,970	18	7,603	1,025	41
	NCP	148	977	5,911	29	8,015	1,403	65

Pennsylvania Electric Company
Demand Allocators

	kWh	Average Demand	Non-Coincident Peak Demand	Excess Demand	Excess Adjusted to Peak	Coincident Peak Demand	Average & Excess
	(1)	(2) = (1)/8760	(3)	(4) = (3) - (2)	(5)	(6)	(7) =(2)+(5)
PN_RS	3,925,693,145	448,138	1,087,983	639,845	393,243	878,030	841,381
PN_RT	281,990,787	32,191	115,182	82,991	51,005	36,136	83,196
PN_GSV	16,737,405	1,911	5,584	3,674	2,258	4,073	4,168
PN_GSS	246,580,313	28,148	82,056	53,908	33,131	50,840	61,280
PN_GSM	3,113,269,529	355,396	787,879	432,483	265,800	712,840	621,196
PN_GSL	1,035,941,122	118,258	278,116	159,858	98,247	236,196	216,505
PN_GP	1,922,421,084	219,454	434,969	215,515	132,453	369,490	351,908
PN_H	29,550,218	3,373	11,508	8,134	4,999	3,426	8,373
PN_LP	2,420,602,154	276,324	496,775	220,451	135,487	371,128	411,811
PN_LP_PRIM	2,240,084,072	255,717	465,795	210,077	129,112	340,669	384,829
PN_LP_TRAN	180,518,082	20,607	39,242	18,635	11,453	30,459	32,060
PN_BRD	636,088	73	200	127	78	51	151
PN_POL	16,070,475	1,835	7,155	5,320	3,270	561	5,104
PN_STLT	38,036,893	4,342	13,839	9,497	5,837	17	10,179
WV_BRD	179,066	20	148	128	79	12	99
WV_GP	2,889,810	330	977	647	397	210	727
WV_GS	21,250,343	2,426	5,911	3,486	2,142	4,776	4,568
WV_POL	82,177	9	29	20	12	2	21
WV_RS	29,773,928	3,399	8,015	4,616	2,837	5,526	6,236
WV_RT	4,056,472	463	1,403	940	578	440	1,041
WV_STLT	170,964	20	65	46	28	-	48

Pennsylvania Power Company
Coincident Peak Demands

Peak Date	Hour	PP_GM	PP_GP	PP_GS	PP_GSR	PP_GSW	PP_GT	PP_OH	PP_PNP	PP_POL	PP_RH	PP_RS	PP_RSW	PP_RT	PP_STLT	PP_MISC
4/4/2013	7	136,233	51,609	71,122	275	13	140,100	6,209	318	0	97,648	202,362	2,583	9,001	0	630
5/31/2013	16	193,166	65,144	99,007	380	20	198,665	6,086	635	0	32,751	215,698	2,475	8,342	0	468
6/25/2013	15	209,695	65,831	113,223	460	17	198,461	6,736	765	0	42,996	266,695	2,331	9,732	0	526
7/16/2013	13	229,168	68,348	125,670	607	15	185,857	6,673	994	0	38,459	255,556	2,028	9,247	0	683
8/21/2013	16	178,113	62,455	90,946	387	16	179,226	5,551	667	0	39,307	244,537	2,169	8,566	0	497
9/11/2013	13	248,024	75,420	127,294	551	16	202,935	6,015	874	0	23,460	175,752	1,784	6,120	0	760
10/4/2013	15	180,084	56,467	90,283	381	14	176,168	4,979	571	0	22,350	144,649	1,602	4,990	0	585
11/25/2013	10	180,687	48,748	102,080	450	13	172,521	8,314	487	0	68,123	169,967	1,758	6,453	0	982
12/10/2013	19	108,857	50,381	55,636	197	12	181,681	6,796	185	658	94,029	273,737	2,757	10,344	1,422	462
1/29/2014	9	204,626	63,274	130,361	558	15	213,999	14,173	413	0	124,650	258,941	2,340	9,338	0	1,441
2/28/2014	8	170,974	56,343	102,735	412	13	163,363	10,019	391	0	108,306	224,921	2,129	7,958	0	1,132
3/6/2014	11	199,933	58,772	121,755	496	13	159,177	10,412	471	0	72,261	186,999	1,873	6,668	0	1,245

Pennsylvania Power Company
Non-Coincident Peak Demands

Year	Month	PP_GM	PP_GS	PP_GP	PP_GSR	PP_GSW	PP_GT	PP_OH	PP_PNP	PP_POL	PP_RH	PP_RS	PP_RSW	PP_RT	PP_STLT
2013	4	172,792	95,018	53,040	380	16	200,768	7,701	597	997	102,027	227,292	2,973	9,858	2,197
2013	5	229,822	122,177	70,028	509	20	198,665	6,784	942	1,099	58,123	301,358	3,270	11,087	2,367
2013	6	225,191	122,656	69,084	507	17	198,461	6,896	848	1,129	54,846	351,794	3,372	13,203	2,340
2013	7	229,168	125,670	70,909	607	17	203,058	6,896	994	1,144	59,353	386,516	3,225	14,259	2,516
2013	8	212,650	110,950	67,244	511	17	188,766	6,398	891	1,089	49,855	311,032	2,994	11,184	2,306
2013	9	248,024	127,294	75,420	551	19	204,137	6,360	874	1,122	45,449	339,235	3,174	11,373	2,437
2013	10	193,062	98,225	59,424	427	14	190,968	5,156	647	1,106	66,028	225,944	2,624	8,088	2,351
2013	11	184,876	104,235	53,635	466	13	214,431	8,314	530	903	107,563	290,221	3,146	11,158	2,027
2013	12	203,405	112,873	68,573	473	15	232,999	9,924	457	924	110,052	298,944	3,026	11,148	1,999
2014	1	207,276	131,904	64,168	562	16	240,069	14,173	425	861	150,756	344,944	3,214	12,451	1,839
2014	2	181,214	113,542	56,343	462	14	205,259	12,077	418	825	123,786	305,150	2,847	10,763	1,644
2014	3	199,933	122,178	59,218	515	14	220,976	10,583	485	908	121,990	296,135	3,016	10,678	1,949
	NCP	248,024	131,904	75,420	607	20	240,069	14,173	994	1,144	150,756	386,516	3,372	14,259	2,516

Pennsylvania Power Company
Demand Allocators

	kWh	Average Demand	Non-Coincident Peak Demand	Excess Demand	Excess Adjusted to Peak	Coincident Peak Demand	Average & Excess
	(1)	(2) = (1)/8760	(3)	(4) = (3) - (2)	(5)	(6)	(7) =(2)+(5)
PP_RS	1,316,437,064	150,278	400,775	250,497	174,040	268,279	324,318
PP_RH	347,121,842	39,626	150,756	111,131	77,211	132,608	116,837
PP_RSW	13,050,025	1,490	3,372	1,882	1,308	9,008	2,797
PP_GSR	1,656,762	189	607	418	290	558	479
PP_GS	430,282,064	49,119	131,904	82,785	57,517	130,361	106,636
PP_GM	857,247,669	97,859	248,024	150,165	104,332	204,626	202,191
PP_OH	34,890,717	3,983	14,173	10,190	7,080	14,173	11,063
PP_PNP	2,209,830	252	994	742	516	413	768
PP_POL	2,833,460	323	1,144	820	570	-	893
PP_OH	34,890,717	3,983	14,173	10,190	7,080	14,173	11,063
PP_GP	375,452,727	42,860	75,420	32,560	22,622	63,274	65,482
PP_GT	1,153,358,889	131,662	240,069	108,407	75,319	213,999	206,981
PP_STLT	6,225,920	711	2,516	1,805	1,254	-	1,965

West Pennsylvania Power Company
Coincident Peak Demands

Date	Hour (HE EPT)	Monthly Peak (kWh)	WP_AGR	WP_GS10	WP_GS20	WP_GS22	WP_GS23	WP_GS24	WP_GS30L	WP_GS30S	WP_MISC	WP_POL	WP_PP40
4/4/2013	8	2,989,469	8	2,988	435,906	5,645	-	1	300,795	283,499	480	2	568,353
5/21/2013	18	3,283,756	12	3,557	460,881	4,526	-	1	323,570	306,235	510	4	556,535
6/24/2013	18	3,424,135	12	4,156	485,244	4,595	-	3	322,663	304,032	3,124	4	525,277
7/18/2013	17	3,798,227	13	4,681	564,131	5,410	-	1	352,207	346,648	631	4	625,906
8/30/2013	17	3,425,151	13	4,090	547,361	5,251	-	5	342,419	355,791	659	4	614,903
9/10/2013	17	3,608,040	44	3,495	499,577	4,856	-	4	422,193	378,142	56	5	732,336
10/24/2013	20	2,799,680	8	2,837	366,848	4,245	162	6	244,364	230,186	39	6,201	506,434
11/25/2013	9	3,187,367	11	3,267	492,111	6,293	-	2	319,164	317,210	62	4	581,961
12/12/2013	19	3,508,592	8	3,098	416,025	6,159	76	5	297,826	264,206	60	5,988	628,737
1/7/2014	20	3,922,742	10	3,445	469,381	7,361	87	3	309,543	289,938	68	6,438	642,032
2/28/2014	8	3,592,207	10	2,905	474,498	6,765	-	2	310,274	310,426	72	-	611,314
3/4/2014	8	3,493,253	11	3,071	488,558	6,956	-	2	318,331	306,082	79	-	588,996

Date	Hour (HE EPT)	WP_PP40_TRAN	WP_PP40_PRIM_SEC	WP_PP41	WP_PP44	WP_PP46	WP_PSU	WP_RS	WP_STLT
4/4/2013	8	30,391	537,961	11,340	7,956	111,877	22,292	1,233,635	-
5/21/2013	18	16,943	539,591	5,614	8,910	259,087	38,397	1,311,753	-
6/24/2013	18	8,017	517,260	17,188	8,918	240,840	42,443	1,460,740	-
7/18/2013	17	17,528	608,378	15,335	9,285	190,033	52,399	1,625,673	-
8/30/2013	17	643	614,259	17,811	9,938	220,901	52,046	1,248,508	-
9/10/2013	17	675	731,661	18,194	10,726	287,315	62,896	1,182,618	-
10/24/2013	20	575	505,859	13,514	8,112	231,936	26,047	1,144,272	10,510
11/25/2013	9	51,748	530,214	6,447	8,247	209,533	24,808	1,212,276	-
12/12/2013	19	49,192	579,544	16,085	30	247,560	27,545	1,579,399	9,865
1/7/2014	20	53,028	589,004	11,455	1,892	229,533	24,836	1,907,793	10,831
2/28/2014	8	51,615	559,699	7,510	31	209,785	25,446	1,625,399	-
3/4/2014	8	51,199	537,797	11,748	29	181,903	24,089	1,556,475	-

West Pennsylvania Power Company
Non-Coincident Peak Demands

Year	Month	WP_AGR	WP_GS10	WP_GS20	WP_GS22	WP_GS23	WP_GS24	WP_GS30L	WP_GS30S	WP_MISC	WP_POL	WP_PP40
2013	4	83	4,059	533,911	7,258	228	2	356,429	311,625	578	8,958	656,734
2013	5	26	3,902	525,186	4,893	190	2	398,196	371,715	615	9,553	644,159
2013	6	13	5,271	576,973	5,577	179	4	372,536	364,939	4,110	10,298	626,976
2013	7	14	5,531	645,609	6,068	173	3	396,242	395,624	1,579	10,425	661,728
2013	8	14	4,238	575,954	5,625	286	5	391,601	386,424	715	10,624	686,984
2013	9	74	5,100	605,151	6,083	288	6	467,920	434,097	57	9,874	766,280
2013	10	93	4,115	495,074	5,031	321	6	360,018	339,283	48	9,521	675,278
2013	11	12	4,134	545,583	7,455	181	6	352,382	343,235	67	7,422	708,522
2013	12	11	3,488	532,719	7,171	108	6	334,058	331,458	70	6,977	677,258
2014	1	14	6,722	896,802	13,608	98	6	356,803	418,765	99	7,123	720,985
2014	2	12	3,663	559,709	8,175	105	2	326,965	342,139	85	7,082	691,499
2014	3	12	4,620	594,977	9,382	168	2	341,504	349,971	85	8,977	759,262
	NCP	93	6,722	896,802	13,608	321	6	467,920	434,097	4,110	10,624	766,280

Year	Month	WP_PP40_PRIM_SEC	WP_PP40_TRAN	WP_PP41	WP_PP44	WP_PP46	WP_PSU	WP_RS	WP_STLT
2013	4	628,567	39,487	28,005	9,578	264,741	42,075	1,266,355	16,416
2013	5	627,725	31,332	28,048	9,893	274,731	45,840	1,409,985	16,400
2013	6	610,664	20,645	28,205	10,608	276,731	49,595	1,569,139	18,120
2013	7	644,335	24,971	30,559	10,623	280,422	55,280	1,722,517	17,555
2013	8	686,562	2,571	30,226	11,140	277,594	54,707	1,505,858	17,364
2013	9	765,563	22,491	28,159	13,105	299,493	64,379	1,394,152	16,644
2013	10	674,747	15,053	23,316	12,325	270,901	61,713	1,309,551	15,295
2013	11	665,380	59,575	26,541	10,220	296,384	35,881	1,512,578	12,531
2013	12	635,543	62,163	25,144	10,084	268,441	37,509	1,613,374	11,541
2014	1	667,814	68,469	25,092	10,231	273,825	33,260	1,956,422	11,383
2014	2	636,945	62,277	25,654	9,689	271,350	31,805	1,646,591	13,254
2014	3	714,038	69,859	18,594	11,050	286,203	32,124	1,653,385	14,994
	NCP	765,563	69,859	30,559	13,105	299,493	64,379	1,956,422	18,120

West Pennsylvania Power Company
Demand Allocators

	kWh	Average Demand	Non-Coincident Peak Demand	Excess Demand	Excess Adjusted to Peak	Coincident Peak Demand	Average & Excess
	(1)	(2) = (1)/8760	(3)	(4) = (3) - (2)	(5)	(6)	(7) =(2)+(5)
WP_AGR	-	-	93	93	55	10	55
WP_GS10	19,028,167	2,172	6,722	4,550	2,678	3,445	4,850
WP_GS20	2,609,741,975	297,916	896,802	598,886	352,528	469,381	650,444
WP_GS22	29,999,009	3,425	13,608	10,183	5,994	7,361	9,419
WP_GS23	545,597	62	321	259	153	87	215
WP_GS24	14,585	2	6	5	3	3	5
WP_GS30L	2,020,481,214	230,649	467,920	237,272	139,668	309,543	370,316
WP_GS30S	1,752,002,096	200,000	434,097	234,097	137,799	289,938	337,799
WP_POL	26,567,154	3,033	10,624	7,591	4,469	6,438	7,501
WP_PP40	4,365,064,052	498,295	766,280	267,985	157,747	642,032	656,042
WP_PP40_PRIM_SEC	4,219,383,847	481,665	765,563	283,898	167,114	589,004	648,779
WP_PP40_TRAN	145,680,205	16,630	69,859	53,229	31,333	53,028	47,963
WP_PP41	85,962,009	9,813	30,559	20,746	12,212	11,455	22,025
WP_PP44	64,185,779	7,327	13,105	5,778	3,401	1,892	10,728
WP_PP46	1,465,895,705	167,340	299,493	132,154	77,791	229,533	245,131
WP_PSU	212,485,334	24,256	64,379	40,123	23,618	24,836	47,874
WP_RS	7,090,452,673	809,412	1,956,422	1,147,010	675,176	1,907,793	1,484,588
WP_STLT	47,082,616	5,375	18,120	12,745	7,502	10,831	12,877

Exhibit HES-2
Supporting Study No. 2
Plant Allocator

Company	Utility Acct	Total Gross Plant	Total Reserve	Total Net plant	Transmission %	Distribution%	General Plant Gross - Transmission	General Plant Gross - Distribution	General Plant Reserves - Transmission	General Plant Reserves - Distribution	General Plant Net Book - Transmission	General Plant Net Book - Distribution
	30300 - Misc. Intangible Plant Total	38,675,264.58	30,402,370.74	8,272,893.84	16.75%	83.25%	6,477,720.06	32,197,544.52	5,092,093.08	25,310,277.66	1,385,626.99	6,887,266.85
	38910 - Fee Land Total	2,672,807.80	0.00	2,672,807.80	16.75%	83.25%	447,668.58	2,225,139.22	-	-	447,668.58	2,225,139.22
	38920 - Easements Total	18,077.52	15,206.56	2,870.96	16.75%	83.25%	3,027.80	15,049.72	2,546.95	12,659.61	480.86	2,390.10
	39010 - Structures, Improvements Total	85,738,056.96	44,283,604.17	41,454,452.79	16.75%	83.25%	14,360,267.16	71,377,789.80	7,417,060.86	36,866,543.31	6,943,206.30	34,511,246.49
	39020 - Clearing, Grading of Land Total	12,466,281.69	7,360,715.60	5,105,566.09	16.75%	83.25%	2,087,977.52	10,378,304.17	1,232,846.26	6,127,869.34	855,131.27	4,250,434.83
	39030 - Struct Imprv, Leasehold Imp Total	16,753.91	4,293.31	12,460.60	16.75%	83.25%	2,806.11	13,947.80	719.09	3,574.22	2,087.03	10,373.57
	39110 - Office Furn., Mech. Equip. Total	16,630,775.00	14,646,200.96	1,984,574.04	16.75%	83.25%	2,785,488.50	13,845,286.50	2,453,092.20	12,193,108.76	332,396.31	1,652,177.74
	39115 - Office Machines Total	5,920,633.10	5,920,633.10	0.00	16.75%	83.25%	991,646.84	4,928,986.26	991,646.84	4,928,986.26	-	-
	39120 - Data Processing Equipment Total	5,529,519.82	2,326,264.88	3,203,254.94	16.75%	83.25%	926,139.27	4,603,380.55	389,626.11	1,936,638.78	536,513.17	2,666,741.77
	39125 - Information System Total	(11,738.36)	(2,944.46)	(8,793.90)	16.75%	83.25%	(1,966.06)	(9,772.30)	(493.17)	(2,451.29)	(1,472.89)	(7,321.01)
	39200 - Transportation Equipment Total	1,066,971.10	619,389.10	447,582.00	16.75%	83.25%	178,706.99	888,264.11	103,741.48	515,647.62	74,965.51	372,616.49
	39300 - Stores Equipment Total	1,411,421.83	1,404,210.39	7,211.44	16.75%	83.25%	236,399.04	1,175,022.79	235,191.20	1,169,019.19	1,207.84	6,003.60
	39400 - Tools, Shop, Garage Equip. Total	11,711,828.47	6,684,476.22	5,027,352.25	16.75%	83.25%	1,961,614.15	9,750,214.32	1,119,582.92	5,564,893.30	842,031.23	4,185,321.02
	39500 - Laboratory Equipment Total	3,047,683.99	3,047,683.99	0.00	16.75%	83.25%	510,456.59	2,537,227.40	510,456.59	2,537,227.40	-	-
	39600 - Power Operated Equipment Total	751,657.85	613,115.25	138,542.60	16.75%	83.25%	125,895.17	625,762.68	102,690.67	510,424.58	23,204.50	115,338.10
	39700 - Communication Equipment Total	34,023,088.25	23,913,531.21	10,109,557.04	53.00%	47.00%	18,032,236.77	15,990,851.48	12,674,171.54	11,239,359.67	5,358,065.23	4,751,491.81
	39800 - Misc. Equipment Total	2,586,559.95	2,505,459.74	81,100.21	16.75%	83.25%	433,222.93	2,153,337.02	419,639.45	2,085,820.29	13,583.47	67,516.74
MTED Metropolitan Edison Total		222,255,643.46	143,744,210.76	78,511,432.70	22.30%	77.70%	49,559,307.44	172,696,336.02	32,744,612.06	110,999,598.70	16,814,695.39	61,696,737.31
	30300 - Misc. Intangible Plant Total	40,517,785.60	29,315,896.66	11,201,888.94	17.32%	82.68%	7,018,490.82	33,499,294.78	5,078,099.62	24,237,797.04	1,940,391.20	9,261,497.73
	38910 - Fee Land Total	1,384,075.48	0.00	1,384,075.48	17.32%	82.68%	239,749.55	1,144,325.93	-	-	239,749.55	1,144,325.93
	38920 - Easements Total	21,378.19	11,870.49	9,507.70	17.32%	82.68%	3,703.13	17,675.06	2,056.21	9,814.28	1,646.92	7,860.78
	39010 - Structures, Improvements Total	55,225,145.82	26,135,006.75	29,090,139.07	17.32%	82.68%	9,566,099.76	45,659,046.06	4,527,105.87	21,607,900.88	5,038,993.89	24,051,145.18
	39020 - Clearing, Grading of Land Total	7,342,584.69	4,374,808.94	2,967,775.75	17.32%	82.68%	1,271,882.52	6,070,702.17	757,804.40	3,617,004.53	514,078.12	2,453,697.64
	39030 - Struct Imprv, Leasehold Imp Total	18,348.67	788.03	17,560.64	17.32%	82.68%	3,178.36	15,170.31	136.50	651.53	3,041.85	14,518.79
	39110 - Office Furn., Mech. Equip. Total	5,902,315.25	5,902,315.25	0.00	17.32%	82.68%	1,022,399.05	4,879,916.20	1,022,399.05	4,879,916.20	-	-
	39115 - Office Machines Total	1,718,127.58	1,718,153.69	(26.11)	17.32%	82.68%	297,614.06	1,420,513.52	297,618.58	1,420,535.11	(4.52)	(21.59)
	39120 - Data Processing Equipment Total	3,576,117.96	811,836.97	2,764,280.99	17.32%	82.68%	619,455.15	2,956,662.81	140,626.40	671,210.57	478,828.75	2,285,452.24
	39200 - Transportation Equipment Total	3,496,047.52	1,857,140.26	1,638,907.26	17.32%	82.68%	605,585.35	2,890,462.17	321,693.84	1,535,446.42	283,891.52	1,355,015.75
	39300 - Stores Equipment Total	1,528,101.97	1,526,063.05	2,038.92	17.32%	82.68%	264,697.82	1,263,404.15	264,344.64	1,261,718.41	353.18	1,685.74
	39400 - Tools, Shop, Garage Equip. Total	13,236,826.77	7,070,061.37	6,166,765.40	17.32%	82.68%	2,292,883.13	10,943,943.64	1,224,676.03	5,845,385.34	1,068,207.10	5,098,558.30
	39500 - Laboratory Equipment Total	6,088,985.59	6,088,985.59	0.00	17.32%	82.68%	1,054,734.08	5,034,251.51	1,054,734.08	5,034,251.51	-	-
	39600 - Power Operated Equipment Total	5,143,382.14	4,510,108.59	633,273.55	17.32%	82.68%	890,936.65	4,252,445.49	781,241.01	3,728,867.58	109,695.64	523,577.91
	39700 - Communication Equipment Total	31,713,741.48	22,484,458.35	9,229,283.13	53.00%	47.00%	16,808,282.98	14,905,458.50	11,916,762.92	10,567,695.42	4,891,520.06	4,337,763.07
	39800 - Misc. Equipment Total	3,331,355.74	3,190,867.82	140,487.92	17.32%	82.68%	577,057.44	2,754,298.30	552,722.12	2,638,145.70	24,335.32	116,152.60
PELE Pennsylvania Electric Total		180,244,320.45	114,998,361.80	65,245,958.65	23.60%	76.40%	42,536,749.87	137,707,570.58	27,942,021.28	87,056,340.52	14,594,728.59	50,651,230.05
	30300 - Misc. Intangible Plant Total	39,991,847.40	10,537,644.20	29,454,203.20	14.16%	85.84%	5,661,645.84	34,330,201.56	1,491,814.29	9,045,829.91	4,169,831.55	25,284,371.65
	38910 - Fee Land Total	2,130,319.95	0.00	2,130,319.95	14.16%	85.84%	301,589.40	1,828,730.55	-	-	301,589.40	1,828,730.55
	38920 - Easements Total	205,390.18	13,378.78	192,011.40	14.16%	85.84%	29,077.09	176,313.09	1,894.03	11,484.75	27,183.05	164,828.35
	39010 - Structures, Improvements Total	69,444,516.24	4,886,676.35	64,557,839.89	14.16%	85.84%	9,831,260.16	59,613,256.08	691,806.77	4,194,869.58	9,139,453.39	55,418,386.49
	39030 - Struct Imprv, Leasehold Imp Total	613,473.03	567,024.45	46,448.58	14.16%	85.84%	86,849.38	526,623.65	80,273.65	486,750.80	6,575.73	39,872.85
	39110 - Office Furn., Mech. Equip. Total	4,671,778.18	1,521,226.47	3,150,551.71	14.16%	85.84%	661,383.64	4,010,394.54	215,360.03	1,305,866.44	446,023.61	2,704,528.10
	39115 - Office Machines Total	312,391.07	139,182.49	173,208.58	14.16%	85.84%	44,225.20	268,165.87	19,704.07	119,478.42	24,521.14	148,687.44
	39120 - Data Processing Equipment Total	7,664,739.34	3,638,155.64	4,026,583.70	14.16%	85.84%	1,085,097.15	6,579,642.19	515,053.69	3,123,101.95	570,043.45	3,456,540.24
	39200 - Transportation Equipment Total	2,383,947.30	254,655.51	2,129,291.79	14.16%	85.84%	337,495.42	2,046,451.88	36,051.58	218,603.93	301,443.84	1,827,847.95
	39300 - Stores Equipment Total	371,472.30	86,128.45	285,343.85	14.16%	85.84%	52,589.33	318,882.97	12,193.20	73,935.25	40,396.13	244,947.72
	39400 - Tools, Shop, Garage Equip. Total	6,942,297.26	1,765,844.63	5,176,452.63	14.16%	85.84%	982,821.02	5,959,476.24	249,990.62	1,515,854.00	732,830.40	4,443,622.23
	39500 - Laboratory Equipment Total	776,231.78	186,567.87	589,663.91	14.16%	85.84%	109,891.13	666,340.65	26,412.41	160,155.46	83,478.72	506,185.19
	39600 - Power Operated Equipment Total	63,994.93	14,316.98	49,677.95	14.16%	85.84%	9,059.76	54,935.17	2,026.85	12,290.13	7,032.91	42,645.04
	39700 - Communication Equipment Total	22,342,223.02	3,177,697.44	19,164,525.58	53.00%	47.00%	11,841,378.20	10,500,844.82	1,684,179.64	1,493,517.80	10,157,198.56	9,007,327.02
	39800 - Misc. Equipment Total	1,977,870.92	553,512.76	1,424,358.16	14.16%	85.84%	280,007.19	1,697,863.73	78,360.80	475,151.95	201,646.39	1,222,711.78
WPCO West Penn Power Total		159,892,492.90	27,342,012.02	132,550,480.88	19.58%	80.42%	31,314,369.91	128,578,122.99	5,105,121.66	22,236,890.36	26,209,248.25	106,341,232.63
Grand Total		587,823,586.50	300,987,899.42	286,835,687.08								

Exhibit HES-2

Supporting Study No. 3

Customer Deposits

Metropolitan Edison Company
Customer Deposits 2013

Rate Category	Deposit Amount
BORD	$ 347.84
GP	$ 1,231,847.91
GS	$ 6,253,874.43
GST	$ 468,358.94
GSV	$ 15,095.57
MS	$ 3,318.49
OL	$ 1,309.41
RS	$ 9,253,667.36
RT	$ 876,593.19
TP	$ 131,551.29
TOTAL	$ 18,235,964.43

Source: SAP Report of GL - Deposit Amount

Pennsylvania Electric Company
Customer Deposits 2013

Rate Category	Deposit Amount
GP	$ 671,426.56
GS	$ 5,963,189.81
GST	$ 336,817.06
GSV	$ 24,233.59
H	$ 1,849.32
LP	$ 83,157.29
RS	$ 7,459,606.57
RT	$ 352,478.26
TOTAL	$ 14,892,758.46

Source: SAP Report of GL - Deposit Amount

Pennsylvania Power Company
Customer Deposits 2013

Rate Category	Deposit Amount
GM	$ 466,657.20
GP	$ 40,365.22
GS	$ 947,111.37
GSR	$ 2,194.54
GT	$ 137,993.94
PNP	$ 4,906.02
RH	$ 196,426.43
RS	$ 1,562,053.54
WH	$ 74,786.99
TOTAL	$ 3,432,495.26

Source: SAP Report of GL - Deposit Amount

West Penn Power Company
Customer Deposits 2013

Rate Category	Deposit Amount
GP	$ 1,456,608.80
GS	$ 7,964,694.33
GSV	$ 28,191.68
OL	$ 15,502.83
RS	$ 8,975,208.52
STLT	$ 4,303.76
TOTAL	$ 18,444,509.91

Source: SAP Report of GL - Deposit Amount

Exhibit HES-2

Supporting Study No. 4

Customer Accounting & Information

FERC Customer Accounting Analysis

Metropolitan Edison Company

Year Ending December 2013

FERC 902 Meter Reading Expenses

Overview

The allocation methodology required a two-step process. First, a weighting factor was calculated for each rate class based on the number of meters in that rate class and the read time for those meters. Then, these weight factors were used to determine the allocation of the FERC balance across the rate classes.

Source of Data

FERC 902 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

A Brio query was run from EDW to obtain the number of meters in each rate category by Customer Service Systems.

Read times for each meter by rate class was obtained from Customer Service Analytics. Streetlights were excluded from the calculations as a majority of those accounts are not metered.

Allocation Methodology

- The average number of customers (a) for each rate category is based on the FERC form 1.
- The weighted factor (b) is based on the read time for each rate category and represents the minutes per meter to obtain a reading.
- The Weighted Customer Count (c) is the Customer Count (a) X Weighted factor (b)
- Total $ by Rate (d) was calculated by taking the Weighted Customer Count by rate class (c) divided by Total Weighted Customer Count X Total FERC Balance equals FERC balance by rate class.

Example:

Customers By Rate Class	Average Number of Customers (a)	Weighted Factor (b)	Weighted Customer Count (c) = (a) * (b)	Total $ by Rate (d)
Residential				
Rate RS	444,991	1.04388	464,517	$2,973,472
Rate RT	42,713	1.59968	68,327	$437,377
Rate GSV	270	2.22220	600	$3,841
Total Residential	**487,974**		**533,445**	**$3,414,690**
Commercial				
Rate GSS	40,198	1.54490	62,102	$397,528
Rate GSM	23,722	2.01104	47,706	$305,375
Rate MS	142	2.69956	383	$2,454
Rate OL	1,095	-	-	-
Total Commercial	**65,157**		**110,191**	**$705,356**
Industrial				
Rate GST	350	2.00000	700	$4,481
Rate GP	502	2.00000	1,004	$6,427
Rate TP	23	2.10382	48	$310
Total Industrial	**875**		**1,752**	**$11,217**
Public St & Highway Lighting				
Public St & Highway Lighting	590	-	-	-
Total Public St & Highway Lighting	**590**		-	-
Total	**554,596**		**645,388**	**$4,131,264**

FERC 903 Customer Records Collection Expenses

Overview

The 2013 FERC Form 1 average number of customers was used to calculate a weighted distribution of the FERC 903.

Source of Data

FERC 903 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the average number of customers from the FERC Form 1 (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the combined FERC 903 balance to determine the distribution of dollars across the rate classes (c).

Example:

Title of Rate Schedule	Average Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
Rate RS	444,991	0.8024	$5,020,433
Rate RT	42,713	0.0770	$481,892
Rate GSV	270	0.0005	$3,046
Total Residential	**487,974**	**0.8799**	**$5,505,372**
Commercial			
Rate GSS	40,198	0.0725	$453,518
Rate GSM	23,722	0.0428	$267,634
Rate MS	142	0.0003	$1,602
Rate OL	1,095	0.0020	$12,354
Total Commercial	**65,157**	**0.1175**	**$735,108**
Industrial			
Rate GST	350	0.0006	$3,949
Rate GP	502	0.0009	$5,664
Rate TP	23	0.0000	$259
Total Industrial	**875**	**0.0016**	**$9,872**
Public St & Highway Lighting			
Public St & Highway Lighting	590	0.0011	$6,656
Total Public St & Highway Lighting	**590**	**0.0011**	**$6,656**
Total	**554,596**		**$6,257,008**

FERC 904 Uncollectible Accounts

Overview

The 2013 FERC Form 1 average number of customers was used to calculate a weighted distribution of the FERC 904.

Source of Data

FERC 904 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the average number of customers from the FERC Form 1 (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the combined FERC 904 balance to determine the distribution of dollars across the rate classes (c).

Example:

Title of Rate Schedule	Average Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
Rate RS	444,991	0.8024	$11,500,557
Rate RT	42,713	0.0770	$1,103,895
Rate GSV	270	0.0005	$6,978
Total Residential	**487,974**	**0.8799**	**$12,611,430**
Commercial			
Rate GSS	40,198	0.0725	$1,038,896
Rate GSM	23,722	0.0428	$613,083
Rate MS	142	0.0003	$3,670
Rate OL	1,095	0.0020	$28,300
Total Commercial	**65,157**	**0.1175**	**$1,683,948**
Industrial			
Rate GST	350	0.0006	$9,046
Rate GP	502	0.0009	$12,974
Rate TP	23	0.0000	$594
Total Industrial	**875**	**0.0016**	**$22,614**
Public St & Highway Lighting			
Public St & Highway Lighting	590	0.0011	$15,248
Total Public St & Highway Lighting	**590**	**0.0011**	**$15,248**
Total	**554,596**		**$14,333,240**

FERC 905 Miscellaneous Customer Accounts Expenses

Overview

The 2013 FERC Form 1 average number of customers was used to calculate a weighted distribution of the FERC 905.

Source of Data

FERC 905 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the average number of customers from the FERC Form 1 (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the combined FERC 905 balance to determine the distribution of dollars across the rate classes (c).

Example:

Title of Rate Schedule	Average Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
Rate RS	444,991	0.8024	$191,086
Rate RT	42,713	0.0770	$18,342
Rate GSV	270	0.0005	$116
Total Residential	**487,974**	**0.8799**	**$209,544**
Commercial			
Rate GSS	40,198	0.0725	$17,262
Rate GSM	23,722	0.0428	$10,187
Rate MS	142	0.0003	$61
Rate OL	1,095	0.0020	$470
Total Commercial	**65,157**	**0.1175**	**$27,979**
Industrial			
Rate GST	350	0.0006	$150
Rate GP	502	0.0009	$216
Rate TP	23	0.0000	$10
Total Industrial	**875**	**0.0016**	**$376**
Public St & Highway Lighting			
Public St & Highway Lighting	590	0.0011	$253
Total Public St & Highway Lighting	**590**	**0.0011**	**$253**
Total	**554,596**		**$238,152**

FERC 450 & 451 Forfeited Discounts and Miscellaneous Service Revenues

Overview

The 2013 FERC Form 1 average number of customers was used to calculate a weighted distribution of the FERC 450 and 451 expenses.

Source of Data

FERC 450 and 451 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the average number of customers from the FERC Form 1 (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the combined FERC 450 and 451 balance to determine the distribution of dollars across the rate classes (c).

Example:

Title of Rate Schedule	Average Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
Rate RS	444,991	0.8024	($4,728,372)
Rate RT	42,713	0.0770	($453,858)
Rate GSV	270	0.0005	($2,869)
Total Residential	**487,974**	**0.8799**	**($5,185,099)**
Commercial			
Rate GSS	40,198	0.0725	($427,135)
Rate GSM	23,722	0.0428	($252,064)
Rate MS	142	0.0003	($1,509)
Rate OL	1,095	0.0020	($11,635)
Total Commercial	**65,157**	**0.1175**	**($692,343)**
Industrial			
Rate GST	350	0.0006	($3,719)
Rate GP	502	0.0009	($5,334)
Rate TP	23	0.0000	($244)
Total Industrial	**875**	**0.0016**	**($9,298)**
Public St & Highway Lighting			
Public St & Highway Lighting	590	0.0011	($6,269)
Total Public St & Highway Lighting	**590**	**0.0011**	**($6,269)**
Total	**554,596**		**($5,893,009)**

FERC 908 Customer Assistance Expenses

Overview

Expenses for PA Act 129 charges were excluded from the FERC 908 account balance for 2013. The remaining FERC 908 account balance for 2013 was allocated over RS and RT rate class based on Factors calculated from total number of customers participating in low income programs

Source of Data

FERC 908 account balance for 2013 excluding PA Act 129 charges

Brio Reports run from EDW by Human Services

Allocation Methodology

- RT and RS factors were calculated by dividing the number of customers in each rate (a) by the sum of total customers (b)
- The RS and RT factors were applied to the total FERC balances to determine balances by rate (d & e)

Example:

Company	Balance	RS Balance (d)	RT Balance (e)
Met-Ed	26,388,455	$25,239,093	$1,149,361

Calculations

Customer Count RS (a)	Customer Count RT (a)	Customer Count (b)	RS Factor	RT Factor
17,238	785	18,023	0.956445	0.043555

FERC 910 Miscellaneous Customer Service and Information Expenses

Overview

FERC 910 account balances were distributed based on actual call volume for 2013. Ratios for rate class call volumes were calculated based on call volume and FERC Form 1 Customer Count and then applied to the total FERC balance to distribute the dollars across the rate classes.

Source of Data

FERC 910 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Call Volumes from the IVR Calls by Call Report for 2013

Allocation Methodology

- Cost Allocations by Call Category was done by multiplying the FERC Form 910 Costs by the Percentage of Calls in each category (Residential, Commercial & Industrial, and Streetlight) compared to the total Call Volume. Since commercial and industrial call cannot be broken out, a percentage was established for commercial and for industrial based on the FERC Form 1 average number of customers. This percentage was then applied in order to allocate costs to each of the categories.

Example:

Calls by Customer Category	Count	Percentage	$
Residential	1,691,461	97.99%	$5,070,279
Commercial & Industrial	33,558	1.94%	$100,593
Commercial (Based on Customer Count)[1]	-	*98.67%*	*$99,260*
Industrial (Based on Customer Count)[2]	-	*1.33%*	*$1,333*
Public St & Highway Lighting	1,052	0.06%	$3,153
Total Calls	**1,726,071**	**100.00%**	**$5,174,025**

[1]Commercial (Based on Customer Count) = Total Commercial Customers/Total Commercial & Industrial Customers OR 65,157 / 66,032

[2]Industrial (Based on Customer Count) = Total Industrial Customers / Total Commercial & Industrial Customers OR 875 / 66,032

- To calculate the distribution of dollars across the rate classes (c) the percentage of customer in each rate category was established (b) based on the average number of customers from the FERC Form 1 (a). This percentage was then multiplied by the dollars allocated to each Call Category (Residential, Commercial, Industrial, and Streetlight) established above to determine the dollars

Example:

Customers By Rate Class	Average Number of Customers (a)	Percentage (b)	Total $ by Rate (c)
Residential			
Rate RS	444,991	91.19%	$4,623,665
Rate RT	42,713	8.75%	$443,808
Rate GSV	270	0.06%	$2,805
Total Residential	**487,974**	**100.00%**	**$5,070,279**
Commercial			
Rate GSS	40,198	61.69%	$61,237
Rate GSM	23,722	36.41%	$36,138
Rate MS	142	0.22%	$216
Rate OL	1,095	1.68%	$1,668
Total Commercial	**65,157**	**100.00%**	**$99,260**
Industrial			
Rate GST	350	40.00%	$533
Rate GP	502	57.37%	$765
Rate TP	23	2.63%	$35
Total Industrial	**875**	**100.00%**	**$1,333**
Public St & Highway Lighting			
Public St & Highway Lighting	590	100.00%	$3,153
Total Public St & Highway Lighting	**590**	**100.00%**	**$3,153**
Total	**554,596**		**$5,174,025**

Metropolitan Edison Company Customer Accounting Total Account Dollars Assigned to Rate Group							
Rate	Meter Reading	Customer Records Collection	Uncollectible Accounts	Miscellaneous Customer Accounts	Forfeited Discounts and Miscellaneous Service Revenues	Cust Asst	MISC
Classes	**902**	**903**	**904**	**905**	**450 & 451**	**908**	**910**
Residential							
Rate RS	$2,973,472	$5,020,433	$11,500,557	$191,086	($4,728,372)	$25,239,093	$4,623,665
Rate RT	$437,377	$481,892	$1,103,895	$18,342	($453,858)	$1,149,361	$443,808
Rate GSV	$3,841	$3,046	$6,978	$116	($2,869)	-	$2,805
Total Residential	**$3,414,690**	**$5,505,372**	**$12,611,430**	**$209,544**	**($5,185,099)**	**$26,388,455**	**$5,070,279**
Commercial							
Rate GSS	$397,528	$453,518	$1,038,896	$17,262	($427,135)	-	$61,237
Rate GSM	$305,375	$267,634	$613,083	$10,187	($252,064)	-	$36,138
Rate MS	$2,454	$1,602	$3,670	$61	($1,509)	-	$216
Rate OL	-	$12,354	$28,300	$470	($11,635)	-	$1,668
Total Commercial	**$705,356**	**$735,108**	**$1,683,948**	**$27,979**	**($692,343)**	**-**	**$99,260**
Industrial							
Rate GST	$4,481	$3,949	$9,046	$150	($3,719)	-	$533
Rate GP	$6,427	$5,664	$12,974	$216	($5,334)	-	$765
Rate TP	$310	$259	$594	$10	($244)	-	$35
Total Industrial	**$11,217**	**$9,872**	**$22,614**	**$376**	**($9,298)**	**-**	**$1,333**
Public St & Highway Lighting							
Public St & Highway Lighting	-	$6,656	$15,248	$253	($6,269)	-	$3,153
Total Public St & Highway Lighting	**-**	**$6,656**	**$15,248**	**$253**	**($6,269)**	**-**	**$3,153**
Total	**$4,131,264**	**$6,257,008**	**$14,333,240**	**$238,152**	**($5,893,009)**	**$26,388,455**	**$5,174,025**

FERC Customer Accounting Analysis

Pennsylvania Electric Company

Year Ending December 2013

FERC 902 Meter Reading Expenses

Overview

Once an adjustment was made for NY customers, the remaining costs were allocated based on a two-step process. First, a weighting factor was calculated for each rate class based on the number of meters in that rate class and the read time for those meters. Then, these weight factors were used to determine the allocation of the FERC balance across the rate classes.

Source of Data

FERC 902 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

A Brio query was run from EDW to obtain the number of meters in each rate category by Customer Service Systems.

Read times for each meter by rate class was obtained from Customer Service Analytics. Streetlights were excluded from the calculations as a majority of those accounts are not metered.

Allocation Methodology

Example:

- The average number of customers (a) for each rate category is based on the FERC form 1.
- The weighted factor (b) is based on the read time for each rate category and represents the minutes per meter to obtain a reading.
- The Weighted Customer Count (c) is the Customer Count (a) X Weighted factor (b)
- Total $ by Rate (d) was calculated by taking the Weighted Customer Count by rate class (c) divided by Total Weighted Customer Count X Total FERC Balance equals FERC balance by rate class.

Example:

Customers By Rate Class	Average Number of Customers (a)	Weighted Factor (b)	Weighted Customer Count (c) = (a) * (b)	Total $ by Rate (d)
Residential				
Rate RS	479,015	1.15929	555,319	$3,078,713
Rate RT	20,627	1.68852	34,829	$193,094
Rate GSV	675	1.80891	1,221	$6,769
Total Residential (Excluding NY)	**500,317**		**591,370**	**$3,278,577**
Commercial				
Rate GSS	52,550	1.74938	91,930	$509,663
Rate GSM	28,501	2.08613	59,457	$329,631
Rate H	152	2.22328	338	$1,874
Rate OL	2,458	-	-	-
Total Commercial (Excluding NY)	**83,661**		**151,725**	**$841,167**
Industrial				
Rate GST	419	2.01755	845	$4,687
Rate GP	431	2.01086	867	$4,805
Rate LP	50	2.08942	104	$579
Total Industrial (Excluding NY)	**900**		**1,817**	**$10,071**
Public St & Highway Lighting				
Rate SV	765	-	-	-
Public St & Highway Lighting (Excluding NY)	**765**		-	-
PA Subtotal	**585,643**		**744,911**	**$4,129,815**
NY				
Residential, Commercial, & Industrial	3,757	1.16550	4,379	$24,276
Public St & Highway Lighting	2	-	-	-
NY Subtotal	**3,759**		**4,379**	**$24,276**
Total	**589,402**		**749,289**	**$4,154,091**

FERC 903 Customer Records and Collection Expenses

Overview

Once NY customers were excluded from the FERC 903 balance, the remaining balance was distribute to the rate categories based on the average number of customers from the FERC form 1.

Source of Data

FERC 903 account balance for 2013

2013 FERC Form 1 data was used for average number of customers

Allocation Methodology

- To calculate the dollars that should be excluded for Waverly, NY, a percentage was established for Waverly Customers and PA Customers based on the FERC Form 1 average number of customers. This percentage was then applied in order to allocate the cost amount to be adjusted out.

Example:

Customers by Category	Average Number of Customers	Percentage	$
Residential	**503,617**	**85.45%**	**$5,663,092**
PA	*500,317*	*99.34%*	*$5,625,984*
NY	*3,300*	*0.66%*	*$37,108*
Commercial	**84,117**	**14.27%**	**$945,882**
PA	*83,661*	*99.46%*	*$940,754*
NY	*456*	*0.54%*	*$5,128*
Industrial	**901**	**0.15%**	**$10,132**
PA	*900*	*99.89%*	*$10,120*
NY	*1*	*0.11%*	*$11*
Public St & Highway Lighting	**767**	**0.13%**	**$8,625**
PA	765	*99.74%*	*$8,602*
NY	2	*0.26%*	*$22*
Total	**589,402**		**$6,627,730**

- Once NY expenses were excluded, the weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the customer counts from the FERC Form 1 (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the FERC 903 account balance to determine the distribution of dollars across the rate classes (c).

Example:

Customers By Rate Class	Average Number of Customers (a)	Factor (b)	Total $ by Rate (c)
Residential			
Rate RS	479,015	0.8179	$5,386,446
Rate RT	20,627	0.0352	$ 231,947
Rate GSV	675	0.0012	$ 7,590
Total Residential (Excluding NY)	**500,317**	**0.8543**	**$5,625,984**
Commercial			
Rate GSS	52,550	0.0897	$ 590,916
Rate GSM	28,501	0.0487	$ 320,489
Rate H	152	0.0003	$ 1,709
Rate OL	2,458	0.0042	$ 27,640
Total Commercial (Excluding NY)	**83,661**	**0.1429**	**$940,754**
Industrial			
Rate GST	419	0.0007	$ 4,712
Rate GP	431	0.0007	$ 4,847
Rate LP	50	0.0001	$ 562
Total Industrial (Excluding NY)	**900**	**0.0015**	**$10,120**
Public St & Highway Lighting			
Rate SV	765	0.0013	$ 8,602
Public St & Highway Lighting (Excluding NY)	**765**	**0.0013**	**8,602**
Grand Total (Excluding NY)	**585,643**		**$6,585,461**

FERC 904 Uncollectible Accounts

Overview

Once NY customers were excluded from the FERC 904 balance, the remaining balance was distribute to the rate categories based on the average number of customers from the FERC form 1.

Source of Data

FERC 904 account balance for 2013

2013 FERC Form 1 data was used for average number of customers

Allocation Methodology

- To calculate the dollars that should be excluded for Waverly, NY, a percentage was established for Waverly Customers and PA Customers based on the FERC Form 1 average number of customers. This percentage was then applied in order to allocate the cost amount to be adjusted out.

Example:

Customers by Category	Average Number of Customers	Percentage	$
Residential	**503,617**	**85.45%**	**$9,973,877**
PA	*500,317*	*99.34%*	*$9,908,522*
NY	*3,300*	*0.66%*	*$65,355*
Commercial	**84,117**	**14.27%**	**$1,665,894**
PA	*83,661*	*99.46%*	*$1,656,863*
NY	*456*	*0.54%*	*$9,031*
Industrial	**901**	**0.15%**	**$17,844**
PA	*900*	*99.89%*	*$17,824*
NY	*1*	*0.11%*	*$20*
Public St & Highway Lighting	**767**	**0.13%**	**$15,190**
PA	*765*	*99.74%*	*$15,150*
NY	*2*	*0.26%*	*$40*
Total	**589,402**		**$11,672,805**

- Once NY expenses were excluded, the weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the customer counts from the FERC Form 1 (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the FERC 904 account balance to determine the distribution of dollars across the rate classes (c).

Example:

Customers By Rate Class	Average Number of Customers (a)	Factor (b)	Total $ by Rate (c)
Residential			
Rate RS	479,015	0.8179	$9,486,647
Rate RT	20,627	0.0352	$408,507
Rate GSV	675	0.0012	$13,368
Total Residential (Excluding NY)	**500,317**	**0.8543**	**$9,908,522**
Commercial			
Rate GSS	52,550	0.0897	$1,040,726
Rate GSM	28,501	0.0487	$564,448
Rate H	152	0.0003	$3,010
Rate OL	2,458	0.0042	$48,679
Total Commercial (Excluding NY)	**83,661**	**0.1429**	**$1,656,863**
Industrial			
Rate GST	419	0.0007	$8,298
Rate GP	431	0.0007	$8,536
Rate LP	50	0.0001	$990
Total Industrial (Excluding NY)	**900**	**0.0015**	**$17,824**
Public St & Highway Lighting			
Rate SV	765	0.0013	$15,150
Public St & Highway Lighting (Excluding NY)	**765**	**0.0013**	**$15,150**
Grand Total (Excluding NY)	**585,643**		**$11,598,360**

FERC 905 Miscellaneous Customer Accounts Expenses

Overview

Once NY customers were excluded from the FERC 905 balance, the remaining balance was distribute to the rate categories based on the average number of customers from the FERC form 1.

Source of Data

FERC 905 account balance for 2013

2013 FERC Form 1 data was used for average number of customers

Allocation Methodology

- To calculate the dollars that should be excluded for Waverly, NY, a percentage was established for Waverly Customers and PA Customers based on the FERC Form 1 average number of customers. This percentage was then applied in order to allocate the cost amount to be adjusted out.

Example:

Customers by Category	Average Number of Customers	Percentage	$
Residential	**503,617**	**85.45%**	**$270,484**
PA	*500,317*	*99.34%*	*$268,712*
NY	*3,300*	*0.66%*	*$1,772*
Commercial	**84,117**	**14.27%**	**$45,178**
PA	*83,661*	*99.46%*	*$44,933*
NY	*456*	*0.54%*	*$245*
Industrial	**901**	**0.15%**	**$484**
PA	*900*	*99.89%*	*$483*
NY	*1*	*0.11%*	*$1*
Public St & Highway Lighting	**767**	**0.13%**	**$412**
PA	765	*99.74%*	*$411*
NY	2	*0.26%*	*$1*
Total	**589,402**		**$316,558**

- Once NY expenses were excluded, the weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the customer counts from the FERC Form 1 (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the FERC 905 account balance to determine the distribution of dollars across the rate classes (c).

Example:

Customers By Rate Class	Average Number of Customers (a)	Factor (b)	Total $ by Rate (c)
Residential			
Rate RS	479,015	0.8179	$ 257,271
Rate RT	20,627	0.0352	$ 11,078
Rate GSV	675	0.0012	$ 363
Total Residential (Excluding NY)	**500,317**	**0.8543**	**$268,712**
Commercial			
Rate GSS	52,550	0.0897	$ 28,224
Rate GSM	28,501	0.0487	$ 15,307
Rate H	152	0.0003	$ 82
Rate OL	2,458	0.0042	$ 1,320
Total Commercial (Excluding NY)	**83,661**	**0.1429**	**$44,933**
Industrial			
Rate GST	419	0.0007	$ 225
Rate GP	431	0.0007	$ 231
Rate LP	50	0.0001	$ 27
Total Industrial (Excluding NY)	**900**	**0.0015**	**$483**
Public St & Highway Lighting			
Rate SV	765	0.0013	$ 411
Public St & Highway Lighting (Excluding NY)	**765**	**0.0013**	**411**
Grand Total (Excluding NY)	**585,643**		**$314,539**

FERC 450 & 451 Forfeited Discounts and Miscellaneous Service Revenues

Overview

Once NY customers were excluded from the FERC 450 and 451 balance, the remaining balance was distribute to the rate categories based on the average number of customers from the FERC form 1.

Source of Data

FERC 450 and 451 account balance for 2013

2013 FERC Form 1 data was used for average number of customers

Allocation Methodology

- To calculate the dollars that should be excluded for Waverly, NY, a percentage was established for Waverly Customers and PA Customers based on the FERC Form 1 average number of customers. This percentage was then applied in order to allocate the cost amount to be adjusted out.

Example:

Customers by Category	Average Number of Customers	Percentage	$
Residential	**503,617**	**85.45%**	**($4,295,932)**
PA	*500,317*	*99.34%*	*($4,267,782)*
NY	*3,300*	*0.66%*	*($28,150)*
Commercial	**84,117**	**14.27%**	**($717,531)**
PA	*83,661*	*99.46%*	*($713,641)*
NY	*456*	*0.54%*	*($3,890)*
Industrial	**901**	**0.15%**	**($7,686)**
PA	*900*	*99.89%*	*($7,677)*
NY	*1*	*0.11%*	*($9)*
Public St & Highway Lighting	**767**	**0.13%**	**($6,543)**
PA	765	*99.74%*	*($6,526)*
NY	2	*0.26%*	*($17)*
Total	**589,402**		**($5,027,691)**

- Once NY expenses were excluded, the weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the customer counts from the FERC Form 1 (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the FERC 450 and 451 account balances to determine the distribution of dollars across the rate classes (c).

Example:

Customers By Rate Class	Average Number of Customers (a)	Factor (b)	Total $ by Rate (c)
Residential			
Rate RS	479,015	0.8179	($4,086,073)
Rate RT	20,627	0.0352	($175,952)
Rate GSV	675	0.0012	($5,758)
Total Residential (Excluding NY)	**500,317**	**0.8543**	**($4,267,782)**
Commercial			
Rate GSS	52,550	0.0897	($448,260)
Rate GSM	28,501	0.0487	($243,118)
Rate H	152	0.0003	($1,297)
Rate OL	2,458	0.0042	($20,967)
Total Commercial (Excluding NY)	**83,661**	**0.1429**	**($713,641)**
Industrial			
Rate GST	419	0.0007	($3,574)
Rate GP	431	0.0007	($3,676)
Rate LP	50	0.0001	($427)
Total Industrial (Excluding NY)	**900**	**0.0015**	**($7,677)**
Public St & Highway Lighting			
Rate SV	765	0.0013	($6,526)
Public St & Highway Lighting (Excluding NY)	**765**	**0.0013**	**($6,526)**
Grand Total (Excluding NY)	**585,643**		**($4,995,626)**

FERC 908 Customer Assistance Expenses

Overview

Expenses for PA Act 129 charges were excluded from the FERC 908 account balance for 2013. The remaining FERC 908 account balance for 2013 was allocated over RS and RT rate class based on Factors calculated from total number of customers participating in low income programs

Source of Data

FERC 908 account balance for 2013 excluding PA Act 129 charges

Brio Reports run from EDW by Human Services

Allocation Methodology

- RT and RS factors were calculated by dividing the number of customers in each rate (a) by the sum of total customers (b)
- The RS and RT factors were applied to the total FERC balances to determine balances by rate (d & e)

Example:

Company	Balance	RS Balance (d)	RT Balance (e)
Penelec	29,339,935	$28,510,896	$829,039

Calculations

Customer Count RS (a)	Customer Count RT (a)	Customer Count (b)	RS Factor	RT Factor
24,142	702	24,844	0.971744	0.028256

FERC 910 Miscellaneous Customer Service and Information Expenses

Overview

FERC 910 account balances were distributed based on actual call volume for 2013. Ratios for rate class call volumes were calculated based on call volume and FERC Form 1 Customer Count and then applied to the total FERC balance to distribute the dollars across the rate classes.

Source of Data

FERC 910 account balance for 2013

Customer Counts from FERC Form 1 for 2013

Call Volumes from the IVR Calls by Call Report for 2013

Allocation Methodology

- Cost Allocations by Call Category was done by multiplying the FERC Form 910 Costs by the Percentage of Calls in each category (Residential, Commercial & Industrial, and Streetlight) compared to the total Call Volume. Since commercial and industrial call cannot be broken out, a percentage was established for commercial and for industrial based on the FERC Form 1 customer counts. This percentage was then applied in order to allocate costs to each of the categories.

Example:

Calls by Customer Category	Count	Percentage	$
Residential	2,220,204	98.19%	$5,455,737
Commercial & Industrial	38,964	1.72%	$95,747
Commercial (Based on Customer Count)1	-	*98.94%*	*$94,728*
Industrial (Based on Customer Count)2	-	*1.06%*	*$1,019*
Public St & Highway Lighting	1,880	0.08%	$4,620
Total Calls	**2,261,048**	**100.00%**	**$5,556,104**

[1]Commercial (Based on Customer Count) = Total Commercial Customers/Total Commercial & Industrial Customers OR 84,117 / 85,018

[2]Industrial (Based on Customer Count) = Total Industrial Customers / Total Commercial & Industrial Customers OR 901 / 85,018

- To calculate the dollars that should be excluded for Waverly, NY, a percentage was established for Waverly Customers and PA Customers based on the FERC Form 1 customer counts. This percentage was then applied in order to allocate the cost amount to be adjusted out.

Example:

Calls by Customer Category	Count	Percentage	$
Residential	2,220,204	98.19%	$5,455,737
PA (Based on Customer Count)[3]		*99.34%*	*$5,419,752*
NY (Based on Customer Count)[4]	-	*0.66%*	*$35,985*
Commercial & Industrial	38,964	1.72%	$95,747
Commercial (Based on Customer Count)	-	*98.94%*	*$94,728*
PA (Based on Customer Count)[5]	-	*99.45%*	*$94,211*
NY (Based on Customer Count)[6]	-	*0.55%*	*$516*
Industrial (Based on Customer Count)	-	*1.06%*	*$1,019*
PA (Based on Customer Count)[7]	-	*99.89%*	*$1,018*
NY (Based on Customer Count)[8]	-	*0.11%*	*$1*
Public St & Highway Lighting	1,880	0.08%	$4,620
PA (Based on Customer Count)[9]	-	99.74%	$4,608
NY (Based on Customer Count)[10]	-	0.26%	$12
Total Calls	**2,261,048**	**100.00%**	**$5,556,104**

[3]PA (Based on Customer Count) = Total PA Residential Customers/Total Penelec Residential Customers OR 500,317/ 503,617

[4]NY (Based on Customer Count) = Total NY Residential Customers/Total Penelec Residential Customers OR 3,300 / 503,617

[5]PA (Based on Customer Count) = Total PA Commercial Customers/Total Penelec Commercial Customers OR 83,661 / 84,117

[6]NY (Based on Customer Count) = Total NY Commercial Customers/Total Penelec Commercial Customers OR 456 / 84,117

[7]PA (Based on Customer Count) = Total PA Industrial Customers/Total Penelec Industrial Customers OR 900 / 901

[8]NY (Based on Customer Count) = Total NY Industrial Customers/Total Penelec Industrial Customers OR 1 / 901

[9]PA (Based on Customer Count) = Total PA Streetlight Customers/Total Penelec Streetlight Customers OR 765 / 767

[10]NY (Based on Customer Count) = Total NY Streetlight Customers/Total Penelec Streetlight Customers OR 2 / 767

- To calculate the distribution of dollars across the rate classes (c) the percentage of customer in each rate category was established (b) based on the customer counts from the FERC Form 1 (a). This percentage was then multiplied by the dollars allocated to each Call Category (Residential, Commercial, Industrial, and Streetlight) established above to determine the dollars

Example:

Customers By Rate Class	Average Number of Customers (a)	Percentage (b)	Total $ by Rate (c)
Residential			
Rate RS	479,015	95.74%	$5,188,996
Rate RT	20,627	4.12%	$223,445
Rate GSV	675	0.13%	$7,312
Total Residential (Excluding NY)	**500,317**	**100.00%**	**$5,419,752**
Commercial			
Rate GSS	52,550	62.81%	$59,177
Rate GSM	28,501	34.07%	$32,095
Rate H	152	0.18%	$171
Rate OL	2,458	2.94%	$2,768
Total Commercial (Excluding NY)	**83,661**	**100.00%**	**$94,211**
Industrial			
Rate GST	419	46.56%	$474
Rate GP	431	47.89%	$487
Rate LP	50	5.56%	$57
Total Industrial (Excluding NY)	**900**	**100.00%**	**$1,018**
Public St & Highway Lighting			
Rate SV	765	100.00%	$4,608
Public St & Highway Lighting (Excluding NY)	**765**	**100.00%**	**$4,608**
Grand Total (Excluding NY)	**585,643**		**$5,519,589**

FERC Customer Accounting Analysis

Pennsylvania Power Company

Year Ending December 2013

FERC 902 Meter Reading Expenses

Overview

The allocation methodology required a two-step process. First, a weighting factor was calculated for each rate class based on the number of meters in that rate class and the read time for those meters. Then, these weight factors were used to determine the allocation of the FERC balance across the rate classes.

Source of Data

FERC 902 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

A Brio query was run from EDW to obtain the number of meters in each rate category by Customer Service Systems.

Read times for each meter by rate class was obtained from Customer Service Analytics. Streetlights were excluded from the calculations as a majority of those accounts are not metered.

Allocation Methodology

- The average number of customers (a) for each rate category is based on the FERC form 1.
- The weighted factor (b) is based on the read time for each rate category and represents the minutes per meter to obtain a reading.
- The Weighted Customer Count (c) is the Customer Count (a) X Weighted factor (b)
- Total $ by Rate (d) was calculated by taking the Weighted Customer Count by rate class (c) divided by Total Weighted Customer Count X Total FERC Balance equals FERC balance by rate class.

Example:

Customers By Rate Class	Average Number of Customers (a)	Weighted Factor (b)	Weighted Customer Count (c) = (a) * (b)	Total $ by Rate (d)
Residential				
RS-Residential	121,511	0.88604	107,664	$911,935
RH-Residential Heating	13,612	1.30710	17,792	$150,705
WH-Water Heating	5,868	0.55404	3,251	$27,538
GSPNP-Gen. Service Public or Non-Profit	69	1.57950	109	$923
Total Residential	**141,060**		**128,816**	**$1,091,101**
Commercial				
WH-Water Heating	46	0.30517	14	$119
PLS - Private Outdoor Lighting	831	-	-	-
GS-Gen. Service-Small	17,787	1.19147	21,193	$179,507
GSPNP-Gen. Service Public or Non-Profit	92	1.66855	154	$1,300
GM-Gen. Service-Medium	1,363	1.57950	2,153	$18,235
Total Commercial	**20,119**		**23,513**	**$199,161**
Industrial				
GP-Gen. Service - Prim. Voltage	110	2.16595	238	$2,018
GT-Gen. Service Trans Voltage	40	2.03198	81	$688
Total Industrial	**150**		**320**	**$2,707**
Public St & Highway Lighting				
Public St & Highway Lighting	86	-	-	-
Total Public St & Highway Lighting	**86**	-	-	-
Total	**161,415**		**152,649**	**$1,292,969**

FERC 903 Customer Records and Collection Expenses

Overview

The 2013 FERC Form 1 average number of customers was used to calculate a weighted distribution of the FERC 903 account balances.

Source of Data

FERC 903 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the average number of customers from the FERC Form 1 (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the combined FERC 903 balance to determine the distribution of dollars across the rate classes (c).

Example:

Title of Rate Schedule	Average Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
RS-Residential	121,511	0.7528	$1,394,017
RH-Residential Heating	13,612	0.0843	$156,162
WH-Water Heating	5,868	0.0364	$67,320
GSPNP-Gen. Service Public or Non-Profit	69	0.0004	$792
Total Residential	**141,060**	**0.8739**	**$1,618,290**
Commercial			
WH-Water Heating	46	0.0003	$528
PLS - Private Outdoor Lighting	831	0.0051	$9,534
GS-Gen. Service-Small	17,787	0.1102	$204,059
GSPNP-Gen. Service Public or Non-Profit	92	0.0006	$1,055
GM-Gen. Service-Medium	1,363	0.0084	$15,637
Total Commercial	**20,119**	**0.1246**	**$230,812**
Industrial			
GP-Gen. Service - Prim. Voltage	110	0.0007	$1,262
GT-Gen. Service Trans Voltage	40	0.0002	$459
Total Industrial	**150**	**0.0009**	**$1,721**
Public St & Highway Lighting			
Public Street & Highway Lighting	86	0.0005	$987
Total Public St & Highway Lighting	**86**	**0.0005**	**$987**
TOTAL	**161,415**		**$1,851,810**

FERC 904 Uncollectible Accounts

Overview

The 2013 FERC Form 1 average number of customers was used to calculate a weighted distribution of the FERC 904 account balances.

Source of Data

FERC 904 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the average number of customers from the FERC Form 1 (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the combined FERC 904 balance to determine the distribution of dollars across the rate classes (c).

Example:

Title of Rate Schedule	Average Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
RS-Residential	121,511	0.7528	$1,274,405
RH-Residential Heating	13,612	0.0843	$142,762
WH-Water Heating	5,868	0.0364	$61,543
GSPNP-Gen. Service Public or Non-Profit	69	0.0004	$724
Total Residential	**141,060**	**0.8739**	**$1,479,434**
Commercial			
WH-Water Heating	46	0.0003	$482
PLS - Private Outdoor Lighting	831	0.0051	$8,716
GS-Gen. Service-Small	17,787	0.1102	$186,550
GSPNP-Gen. Service Public or Non-Profit	92	0.0006	$965
GM-Gen. Service-Medium	1,363	0.0084	$14,295
Total Commercial	**20,119**	**0.1246**	**$211,008**
Industrial			
GP-Gen. Service - Prim. Voltage	110	0.0007	$1,154
GT-Gen. Service Trans Voltage	40	0.0002	$420
Total Industrial	**150**	**0.0009**	**$1,573**
Public St & Highway Lighting			
Public Street & Highway Lighting	86	0.0005	$902
Total Public St & Highway Lighting	**86**	**0.0005**	**$902**
TOTAL	**161,415**		**$1,692,917**

FERC 905 Miscellaneous Customer Accounts Expenses

Overview

The 2013 FERC Form 1 average number of customers was used to calculate a weighted distribution of the FERC 905 account balances.

Source of Data

FERC 905 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the average number of customers from the FERC Form 1 (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the combined FERC 905 balance to determine the distribution of dollars across the rate classes (c).

Example:

Title of Rate Schedule	Average Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
RS-Residential	121,511	0.7528	$32,019
RH-Residential Heating	13,612	0.0843	$3,587
WH-Water Heating	5,868	0.0364	$1,546
GSPNP-Gen. Service Public or Non-Profit	69	0.0004	$18
Total Residential	**141,060**	**0.8739**	**$37,170**
Commercial			
WH-Water Heating	46	0.0003	$12
PLS - Private Outdoor Lighting	831	0.0051	$219
GS-Gen. Service-Small	17,787	0.1102	$4,687
GSPNP-Gen. Service Public or Non-Profit	92	0.0006	$24
GM-Gen. Service-Medium	1,363	0.0084	$359
Total Commercial	**20,119**	**0.1246**	**$5,302**
Industrial			
GP-Gen. Service - Prim. Voltage	110	0.0007	$29
GT-Gen. Service Trans Voltage	40	0.0002	$11
Total Industrial	**150**	**0.0009**	**$40**
Public St & Highway Lighting			
Public Street & Highway Lighting	86	0.0005	$23
Total Public St & Highway Lighting	**86**	**0.0005**	**$23**
TOTAL	**161,415**		**$42,534**

FERC 450 & 451 Forfeited Discounts and Miscellaneous Service Revenues

Overview

The 2013 FERC Form 1 average number of customers was used to calculate a weighted distribution of the FERC 450 and 451 account balances.

Source of Data

FERC 450 and 451 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the average number of customers from the FERC Form 1 (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the combined FERC 450 and 451 balances to determine the distribution of dollars across the rate classes (c).

Example:

Title of Rate Schedule	Average Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
RS-Residential	121,511	0.7528	($792,066)
RH-Residential Heating	13,612	0.0843	($88,729)
WH-Water Heating	5,868	0.0364	($38,250)
GSPNP-Gen. Service Public or Non-Profit	69	0.0004	($450)
Total Residential	**141,060**	**0.8739**	**($919,496)**
Commercial			
WH-Water Heating	46	0.0003	($300)
PLS - Private Outdoor Lighting	831	0.0051	($5,417)
GS-Gen. Service-Small	17,787	0.1102	($115,944)
GSPNP-Gen. Service Public or Non-Profit	92	0.0006	($600)
GM-Gen. Service-Medium	1,363	0.0084	($8,885)
Total Commercial	**20,119**	**0.1246**	**($131,145)**
Industrial			
GP-Gen. Service - Prim. Voltage	110	0.0007	($717)
GT-Gen. Service Trans Voltage	40	0.0002	($261)
Total Industrial	**150**	**0.0009**	**($978)**
Public St & Highway Lighting			
Public Street & Highway Lighting	86	0.0005	($561)
Total Public St & Highway Lighting	**86**	**0.0005**	**($561)**
TOTAL	**161,415**		**($1,052,179)**

FERC 908 Customer Assistance Expenses

Overview

Expenses for PA Act 129 charges were excluded from the FERC 908 account balance for 2013. FERC 908 account balance for 2013 was allocated to RS as that was the only rate schedule with customers receiving assistance.

Source of Data

FERC 908 account balance for 2013 excluding PA Act 129 charges

Allocation Methodology

- The FERC 908 account balance was allocated to RS Rate (a)

Example:

Company	Balance	RS Balance (a)
Penn Power	7,570,549	$7,570,549

FERC 910 Miscellaneous Customer Service and Information Expenses

Overview

FERC 910 account balances were distributed based on actual call volume for 2013. Ratios for rate class call volumes were calculated based on call volume and FERC Form 1 Customer Count and then applied to the total FERC balance to distribute the dollars across the rate classes.

Source of Data

FERC 910 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Call Volumes from the IVR Calls by Call Report for 2013

Allocation Methodology

- Cost Allocations by Call Category was done by multiplying the FERC Form 910 Costs by the Percentage of Calls in each category (Residential, Commercial & Industrial, and Streetlight) compared to the total Call Volume. Since commercial and industrial call cannot be broken out, a percentage was established for commercial and for industrial based on the FERC Form 1 average number of customers. This percentage was then applied in order to allocate costs to each of the categories.

Example:

Calls by Customer Category	Count	Percentage	$
Residential	455,622	98.12%	$1,456,551
Commercial & Industrial	8,358	1.80%	$26,719
Commercial (Based on Customer Count) [1]	-	*99.26%*	*$26,521*
Industrial (Based on Customer Count) [2]	-	*0.74%*	*$198*
Public Street & Highway Lighting	355	0.08%	$1,135
Total Calls	**464,335**	**100.00%**	**$1,484,405**

[1]Commercial (Based on Customer Count) = Total Commercial Customers/Total Commercial & Industrial Customers OR 20,119 / 20,269

[2]Industrial (Based on Customer Count) = Total Industrial Customers / Total Commercial & Industrial Customers OR 150 / 20,269

- To calculate the distribution of dollars across the rate classes (c) the percentage of customer in each rate category was established (b) based on the average number of customers from the FERC Form 1 (a). This percentage was then multiplied by the dollars allocated to each Call Category (Residential, Commercial, Industrial, and Streetlight) established above to determine the dollars.

Example:

Customers By Rate Class	Average Number of Customers (a)	Percentage (b)	Total $ by Rate (c)
Residential			
RS-Residential	121,511	86.14%	$1,254,693
RH-Residential Heating	13,612	9.65%	$140,554
WH-Water Heating	5,868	4.16%	$60,592
GSPNP-Gen. Service Public or Non-Profit	69	0.05%	$712
Total Residential	**141,060**	**100.00%**	**$1,456,551**
Commercial			
WH-Water Heating	46	0.23%	$61
PLS - Private Outdoor Lighting	831	4.13%	$1,095
GS-Gen. Service-Small	17,787	88.41%	$23,447
GSPNP-Gen. Service Public or Non-Profit	92	0.46%	$121
GM-Gen. Service-Medium	1,363	6.77%	$1,797
Total Commercial	**20,119**	**100.00%**	**$26,521**
Industrial			
GP-Gen. Service - Prim. Voltage	110	73.33%	$145
GT-Gen. Service Trans Voltage	40	26.67%	$53
Total Industrial	**150**	**100.00%**	**$198**
Public St & Highway Lighting			
Public Street & Highway Lighting	86	100.00%	$1,135
Total Public St & Highway Lighting	**86**	**100.00%**	**$1,135**
Total	**161,415**		**$1,484,405**

FERC Customer Accounting Analysis

West Penn Power Company

Year Ending December 2013

FERC 902 Meter Reading Expenses

Overview

The allocation methodology required a two-step process. First, a weighting factor was calculated for each rate class based on the number of meters in that rate class and the read time for those meters. Then, these weight factors were used to determine the allocation of the FERC balance across the rate classes.

Source of Data

FERC 902 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

A Brio query was run from EDW to obtain the number of meters in each rate category by Customer Service Systems.

Read times for each meter by rate class was obtained from Customer Service Analytics. Streetlights were excluded from the calculations as a majority of those accounts are not metered.

Allocation Methodology

- The average number of customers (a) for each rate category is based on the FERC form 1.
- The weighted factor (b) is based on the read time for each rate category and represents the minutes per meter to obtain a reading.
- The Weighted Customer Count (c) is the Customer Count (a) X Weighted factor (b)
- Total $ by Rate (d) was calculated by taking the Weighted Customer Count by rate class (c) divided by Total Weighted Customer Count X Total FERC Balance equals FERC balance by rate class.

Example:

Customers By Rate Class	Average Number of Customers (a)	Weighted Factor (b)	Weighted Customer Count (c) = (a) * (b)	Total $ by Rate (d)
Residential				
10 - R - Residential	615,369	1.22084	751,269	$6,751,091
20 - General Service	85	1.92199	163	$1,468
22 - Church & School	1	2.23014	2	$20
51 - Street Lighting Service	2	-	-	-
52 - Outdoor Lighting Service	2,718	-	-	-
53 - Street Lighting Service	13	-	-	-
57 - Outdoor Lighting Service - EMU	1,341	-	-	-
58 - Outdoor Lighting	1	-	-	-
59 - Outdoor Lighting - EM	1	-	-	-
Total Residential	**619,531**		**751,435**	**$6,752,579**
Commercial				
20 - General Service	80,301	1.92199	154,338	$1,386,917
22 - Church & School	1,342	2.23014	2,993	$26,895
23 - Athletic Field Service	20	2.58086	52	$464
24 - Fair & Carnival Service	8	2.27673	18	$164
30 - General Power Service	1,696	2.89945	4,917	$44,190
40 - Primary Power Service	22	2.00000	44	$395
51 - Street Lighting Service	42	-	-	-
52 - Outdoor Lighting Service	666	-	-	-
53 - Street Lighting Service	99	-	-	-
57 - Outdoor Lighting Service - EMU	435	-	-	-
58 - Outdoor Lighting Service - MU	11	-	-	-
59 - Outdoor Lighting Service - EM	11	-	-	-
37 - Penn State University	1	2.00000	2	$18
Total Commercial	**84,654**		**162,362**	**$1,459,042**

Industrial				
20 - General Service	12,049	1.92199	23,158	$208,104
30 - General Power Service	883	2.89945	2,560	$23,007
40 - Primary Power Service	104	2.00000	208	$1,869
41 - Primary Power Service	3	2.00000	6	$54
44 - Interr Power Service	1	2.00000	2	$18
46 - Primary Power Service	2	2.00000	4	$36
51 - Street Lighting Service	13	-	-	-
52 - Outdoor Lighting Service	53	-	-	-
53 - Street Lighting Service	10	-	-	-
57 - Outdoor Lighting Service - EMU	26	-	-	-
58 - Outdoor Lighting Service - MU	1	-	-	-
59 - Outdoor Lighting Service - EM	1	-	-	-
86 - Alter. Gen. Rider	4	-	-	-
Total Industrial	**13,150**		**25,938**	**$233,088**
Public St & Highway Lighting				
51 - Street Lighting Service	296	-	-	-
52 - Outdoor Lighting Service	1	-	-	-
53 - Street Lighting Service	1	-	-	-
54 - Street Lighting Service	55	-	-	-
55 - Street Lighting Service	5	-	-	-
56 - Street Lighting Service	3	-	-	-
57 - Street Lighting Service - EMU	193	-	-	-
58 - Street Lighting Service - MU	3	-	-	-
59 - Street Lighting Service - EM	1	-	-	-
71 - Street Lighting Service	1	-	-	-
Total Public St & Highway Lightin	**559**	-	-	-
Total	**717,894**		**939,735**	**$8,444,691**

FERC 903 Customer Records and Collection Expenses

Overview

The 2013 FERC Form 1 average number of customers was used to calculate a weighted distribution of the FERC 903 account balances.

Source of Data

FERC 903 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the average number of customers from the FERC Form 1 (a) in each rate category compared to the total customers. This factor (b) was then multiplied by the FERC 903 account balance to determine the distribution of dollars across the rate classes (c).

Example:

Customers By Rate Class	Average Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
10 - R - Residential	615,369	0.85719	$7,659,902
20 - General Service	85	0.00012	$1,058
22 - Church & School	1	0.00000	$12
51 - Street Lighting Service	2	0.00000	$25
52 - Outdoor Lighting Service	2,718	0.00379	$33,833
53 - Street Lighting Service	13	0.00002	$162
57 - Outdoor Lighting Service - EMU	1,341	0.00187	$16,692
58 - Outdoor Lighting	1	0.00000	$12
59 - Outdoor Lighting - EM	1	0.00000	$12
Total Residential	**619,531**	**0.86298**	**$7,711,709**
Commercial			
20 - General Service	80,301	0.11186	$999,559
22 - Church & School	1,342	0.00187	$16,705
23 - Athletic Field Service	20	0.00003	$249
24 - Fair & Carnival Service	8	0.00001	$100
30 - General Power Service	1,696	0.00236	$21,111
40 - Primary Power Service	22	0.00003	$274
51 - Street Lighting Service	42	0.00006	$523
52 - Outdoor Lighting Service	666	0.00093	$8,290
53 - Street Lighting Service	99	0.00014	$1,232
57 - Outdoor Lighting Service - EMU	435	0.00061	$5,415
58 - Outdoor Lighting Service - MU	11	0.00002	$137
59 - Outdoor Lighting Service - EM	11	0.00002	$137
37 - Penn State University	1	0.00000	$12
Total Commercial	**84,654**	**0.11792**	**$1,053,744**

Industrial			
20 - General Service	12,049	0.01678	$149,982
30 - General Power Service	883	0.00123	$10,991
40 - Primary Power Service	104	0.00014	$1,295
41 - Primary Power Service	3	0.00000	$37
44 - Interr Power Service	1	0.00000	$12
46 - Primary Power Service	2	0.00000	$25
51 - Street Lighting Service	13	0.00002	$162
52 - Outdoor Lighting Service	53	0.00007	$660
53 - Street Lighting Service	10	0.00001	$124
57 - Outdoor Lighting Service - EMU	26	0.00004	$324
58 - Outdoor Lighting Service - MU	1	0.00000	$12
59 - Outdoor Lighting Service - EM	1	0.00000	$12
86 - Alter. Gen. Rider	4	0.00001	$50
Total Industrial	**13,150**	**0.01832**	**$163,687**
Public St & Highway Lighting			
51 - Street Lighting Service	296	0.00041	$3,685
52 - Outdoor Lighting Service	1	0.00000	$12
53 - Street Lighting Service	1	0.00000	$12
54 - Street Lighting Service	55	0.00008	$685
55 - Street Lighting Service	5	0.00001	$62
56 - Street Lighting Service	3	0.00000	$37
57 - Street Lighting Service - EMU	193	0.00027	$2,402
58 - Street Lighting Service - MU	3	0.00000	$37
59 - Street Lighting Service - EM	1	0.00000	$12
71 - Street Lighting Service	1	0.00000	$12
Total Public St & Highway Lighting	**559**	**0.00078**	**$6,958**
Total	**717,894**		**$8,936,097**

FERC 904 Uncollectible Accounts

Overview

The 2013 FERC Form 1 average number of customers was used to calculate a weighted distribution of the FERC 904 account balances.

Source of Data

FERC 904 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the average number of customers from the FERC Form 1 (a) in each rate category compared to the total

customers. This factor (b) was then multiplied by the FERC 904 account balance to determine the distribution of dollars across the rate classes (c).

Example:

Customers By Rate Class	Average Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
10 - R - Residential	615,369	0.85719	$8,382,790
20 - General Service	85	0.00012	$1,158
22 - Church & School	1	0.00000	$14
51 - Street Lighting Service	2	0.00000	$27
52 - Outdoor Lighting Service	2,718	0.00379	$37,026
53 - Street Lighting Service	13	0.00002	$177
57 - Outdoor Lighting Service - EMU	1,341	0.00187	$18,268
58 - Outdoor Lighting	1	0.00000	$14
59 - Outdoor Lighting - EM	1	0.00000	$14
Total Residential	**619,531**	**0.86298**	**$8,439,487**
Commercial			
20 - General Service	80,301	0.11186	$1,093,891
22 - Church & School	1,342	0.00187	$18,281
23 - Athletic Field Service	20	0.00003	$272
24 - Fair & Carnival Service	8	0.00001	$109
30 - General Power Service	1,696	0.00236	$23,104
40 - Primary Power Service	22	0.00003	$300
51 - Street Lighting Service	42	0.00006	$572
52 - Outdoor Lighting Service	666	0.00093	$9,073
53 - Street Lighting Service	99	0.00014	$1,349
57 - Outdoor Lighting Service - EMU	435	0.00061	$5,926
58 - Outdoor Lighting Service - MU	11	0.00002	$150
59 - Outdoor Lighting Service - EM	11	0.00002	$150
37 - Penn State University	1	0.00000	$14
Total Commercial	**84,654**	**0.11792**	**$1,153,189**

Industrial			
20 - General Service	12,049	0.01678	$164,136
30 - General Power Service	883	0.00123	$12,029
40 - Primary Power Service	104	0.00014	$1,417
41 - Primary Power Service	3	0.00000	$41
44 - Interr Power Service	1	0.00000	$14
46 - Primary Power Service	2	0.00000	$27
51 - Street Lighting Service	13	0.00002	$177
52 - Outdoor Lighting Service	53	0.00007	$722
53 - Street Lighting Service	10	0.00001	$136
57 - Outdoor Lighting Service - EMU	26	0.00004	$354
58 - Outdoor Lighting Service - MU	1	0.00000	$14
59 - Outdoor Lighting Service - EM	1	0.00000	$14
86 - Alter. Gen. Rider	4	0.00001	$54
Total Industrial	**13,150**	**0.01832**	**$179,134**
Public St & Highway Lighting			
51 - Street Lighting Service	296	0.00041	$4,032
52 - Outdoor Lighting Service	1	0.00000	$14
53 - Street Lighting Service	1	0.00000	$14
54 - Street Lighting Service	55	0.00008	$749
55 - Street Lighting Service	5	0.00001	$68
56 - Street Lighting Service	3	0.00000	$41
57 - Street Lighting Service - EMU	193	0.00027	$2,629
58 - Street Lighting Service - MU	3	0.00000	$41
59 - Street Lighting Service - EM	1	0.00000	$14
71 - Street Lighting Service	1	0.00000	$14
Total Public St & Highway Lighting	**559**	**0.00078**	**$7,615**
Total	**717,894**		**$9,779,425**

FERC 905 Miscellaneous Customer Accounts Expenses

Overview

The 2013 FERC Form 1 average number of customers was used to calculate a weighted distribution of the FERC 905 account balances.

Source of Data

FERC 905 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the average number of customers from the FERC Form 1 (a) in each rate category compared to the total

customers. This factor (b) was then multiplied by the FERC 905 account balance to determine the distribution of dollars across the rate classes (c).

Example:

Customers By Rate Class	Average Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
10 - R - Residential	615,369	0.85719	$108,513
20 - General Service	85	0.00012	$15
22 - Church & School	1	0.00000	$0
51 - Street Lighting Service	2	0.00000	$0
52 - Outdoor Lighting Service	2,718	0.00379	$479
53 - Street Lighting Service	13	0.00002	$2
57 - Outdoor Lighting Service - EMU	1,341	0.00187	$236
58 - Outdoor Lighting	1	0.00000	$0
59 - Outdoor Lighting - EM	1	0.00000	$0
Total Residential	**619,531**	**0.86298**	**$109,246**
Commercial			
20 - General Service	80,301	0.11186	$14,160
22 - Church & School	1,342	0.00187	$237
23 - Athletic Field Service	20	0.00003	$4
24 - Fair & Carnival Service	8	0.00001	$1
30 - General Power Service	1,696	0.00236	$299
40 - Primary Power Service	22	0.00003	$4
51 - Street Lighting Service	42	0.00006	$7
52 - Outdoor Lighting Service	666	0.00093	$117
53 - Street Lighting Service	99	0.00014	$17
57 - Outdoor Lighting Service - EMU	435	0.00061	$77
58 - Outdoor Lighting Service - MU	11	0.00002	$2
59 - Outdoor Lighting Service - EM	11	0.00002	$2
37 - Penn State University	1	0.00000	$0
Total Commercial	**84,654**	**0.11792**	**$14,928**

Industrial			
20 - General Service	12,049	0.01678	$2,125
30 - General Power Service	883	0.00123	$156
40 - Primary Power Service	104	0.00014	$18
41 - Primary Power Service	3	0.00000	$1
44 - Interr Power Service	1	0.00000	$0
46 - Primary Power Service	2	0.00000	$0
51 - Street Lighting Service	13	0.00002	$2
52 - Outdoor Lighting Service	53	0.00007	$9
53 - Street Lighting Service	10	0.00001	$2
57 - Outdoor Lighting Service - EMU	26	0.00004	$5
58 - Outdoor Lighting Service - MU	1	0.00000	$0
59 - Outdoor Lighting Service - EM	1	0.00000	$0
86 - Alter. Gen. Rider	4	0.00001	$1
Total Industrial	**13,150**	**0.01832**	**$2,319**
Public St & Highway Lighting			
51 - Street Lighting Service	296	0.00041	$52
52 - Outdoor Lighting Service	1	0.00000	$0
53 - Street Lighting Service	1	0.00000	$0
54 - Street Lighting Service	55	0.00008	$10
55 - Street Lighting Service	5	0.00001	$1
56 - Street Lighting Service	3	0.00000	$1
57 - Street Lighting Service - EMU	193	0.00027	$34
58 - Street Lighting Service - MU	3	0.00000	$1
59 - Street Lighting Service - EM	1	0.00000	$0
71 - Street Lighting Service	1	0.00000	$0
Total Public St & Highway Lighting	**559**	**0.00078**	**$99**
Total	**717,894**		**$126,592**

FERC 450 & 451 Forfeited Discounts and Miscellaneous Service Revenues

Overview

The 2013 FERC Form 1 average number of customers was used to calculate a weighted distribution of the FERC 450 and 451 expenses.

Source of Data

FERC 450 and 451 account balance for 2013

2013 FERC Form 1 data was used for the average number of customers

Allocation Methodology

The weighted factor (b) used to distribute the dollars for each rate classes was calculated based on the average number of customers from the FERC Form 1 (a) in each rate category compared to the total

customers. This factor (b) was then multiplied by the combined FERC 450 and 451 balance to determine the distribution of dollars across the rate classes (c).

Example:

Customers By Rate Class	Average Number Customers (a)	Factor (b)	$ Total by Rate (c)
Residential			
10 - R - Residential	615,369	0.85719	($3,568,389)
20 - General Service	85	0.00012	($493)
22 - Church & School	1	0.00000	($6)
51 - Street Lighting Service	2	0.00000	($12)
52 - Outdoor Lighting Service	2,718	0.00379	($15,761)
53 - Street Lighting Service	13	0.00002	($75)
57 - Outdoor Lighting Service - EMU	1,341	0.00187	($7,776)
58 - Outdoor Lighting	1	0.00000	($6)
59 - Outdoor Lighting - EM	1	0.00000	($6)
Total Residential	**619,531**	**0.86298**	**($3,592,524)**
Commercial			
20 - General Service	80,301	0.11186	($465,648)
22 - Church & School	1,342	0.00187	($7,782)
23 - Athletic Field Service	20	0.00003	($116)
24 - Fair & Carnival Service	8	0.00001	($46)
30 - General Power Service	1,696	0.00236	($9,835)
40 - Primary Power Service	22	0.00003	($128)
51 - Street Lighting Service	42	0.00006	($244)
52 - Outdoor Lighting Service	666	0.00093	($3,862)
53 - Street Lighting Service	99	0.00014	($574)
57 - Outdoor Lighting Service - EMU	435	0.00061	($2,522)
58 - Outdoor Lighting Service - MU	11	0.00002	($64)
59 - Outdoor Lighting Service - EM	11	0.00002	($64)
37 - Penn State University	1	0.00000	($6)
Total Commercial	**84,654**	**0.11792**	**($490,890)**

Industrial			
20 - General Service	12,049	0.01678	($69,869)
30 - General Power Service	883	0.00123	($5,120)
40 - Primary Power Service	104	0.00014	($603)
41 - Primary Power Service	3	0.00000	($17)
44 - Interr Power Service	1	0.00000	($6)
46 - Primary Power Service	2	0.00000	($12)
51 - Street Lighting Service	13	0.00002	($75)
52 - Outdoor Lighting Service	53	0.00007	($307)
53 - Street Lighting Service	10	0.00001	($58)
57 - Outdoor Lighting Service - EMU	26	0.00004	($151)
58 - Outdoor Lighting Service - MU	1	0.00000	($6)
59 - Outdoor Lighting Service - EM	1	0.00000	($6)
86 - Alter. Gen. Rider	4	0.00001	($23)
Total Industrial	**13,150**	**0.01832**	**($76,254)**
Public St & Highway Lighting			
51 - Street Lighting Service	296	0.00041	($1,716)
52 - Outdoor Lighting Service	1	0.00000	($6)
53 - Street Lighting Service	1	0.00000	($6)
54 - Street Lighting Service	55	0.00008	($319)
55 - Street Lighting Service	5	0.00001	($29)
56 - Street Lighting Service	3	0.00000	($17)
57 - Street Lighting Service - EMU	193	0.00027	($1,119)
58 - Street Lighting Service - MU	3	0.00000	($17)
59 - Street Lighting Service - EM	1	0.00000	($6)
71 - Street Lighting Service	1	0.00000	($6)
Total Public St & Highway Lighting	**559**	**0.00078**	**($3,242)**
Total	**717,894**		**($4,162,909)**

FERC 908 Customer Assistance Expenses

Overview

Expenses for PA Act 129 charges were excluded from the FERC 908 account balance for 2013. FERC 908 account balance for 2013 was allocated to RS as that was the only rate schedule with customers receiving assistance.

Source of Data

FERC 908 account balance for 2013 excluding PA Act 129 charges

Allocation Methodology

- The FERC 908 account balance was allocated to RS Rate (a)

Example:

Company	Balance	RS Balance (a)
West Penn Power	6,490,065	$6,490,065

FERC 910 Miscellaneous Customer Service and Information Expenses

Overview

FERC 910 account balances were distributed based on actual call volume for 2013. Ratios for rate class call volumes were calculated based on call volume and FERC Form 1 Customer Count and then applied to the total FERC balance to distribute the dollars across the rate classes.

Source of Data

FERC 910 account balance for 2013

Customer Counts from FERC Form 1 for 2013

Call Volumes from the IVR Calls by Call Report for 2013

Allocation Methodology

- Cost Allocations by Call Category was done by multiplying the FERC Form 910 Costs by the Percentage of Calls in each category (Residential, Commercial & Industrial, and Streetlight) compared to the total Call Volume. Since commercial and industrial call cannot be broken out, a percentage was established for commercial and for industrial based on the FERC Form 1 customer accounts. This percentage was then applied in order to allocate costs to each of the categories.

Example:

Calls by Customer Category	Count	Percentage	$
Residential	2,115,346	98.34%	$439,159
Commercial & Industrial	32,930	1.53%	$6,836
Commercial (Based on Customer Count)[1]	-	*86.55%*	*$5,917*
Industrial (Based on Customer Count)[2]	-	*13.45%*	*$919*
Public St & Highway Lighting	2,874	0.13%	$597
Total Calls	**2,151,150**	**100.00%**	**$446,592**

[1]Commercial (Based on Customer Count) = Total Commercial Customers/Total Commercial & Industrial Customers OR 84,654 / 97,804

[2]Industrial (Based on Customer Count) = Total Industrial Customers / Total Commercial & Industrial Customers OR 13,150 / 97,804

- To calculate the distribution of dollars across the rate classes (c) the percentage of customer in each rate category was established (b) based on the customer counts from the FERC Form 1 (a). This percentage was then multiplied by the dollars allocated to each Call Category (Residential, Commercial, Industrial, and Streetlight) established above to determine the dollars

Example:

Customers By Rate Class	Average Number Customers (a)	Percentage (b)	Total $ by Rate (c)
Residential			
10 - R - Residential	615,369	99.33%	$436,209
20 - General Service	85	0.01%	$60
22 - Church & School	1	0.00%	$1
51 - Street Lighting Service	2	0.00%	$1
52 - Outdoor Lighting Service	2,718	0.44%	$1,927
53 - Street Lighting Service	13	0.00%	$9
57 - Outdoor Lighting Service - EMU	1,341	0.22%	$951
58 - Outdoor Lighting	1	0.00%	$1
59 - Outdoor Lighting - EM	1	0.00%	$1
Total Residential	**619,531**	**100.00%**	**$439,159**
Commercial			
20 - General Service	80,301	94.86%	$5,613
22 - Church & School	1,342	1.59%	$94
23 - Athletic Field Service	20	0.02%	$1
24 - Fair & Carnival Service	8	0.01%	$1
30 - General Power Service	1,696	2.00%	$119
40 - Primary Power Service	22	0.03%	$2
51 - Street Lighting Service	42	0.05%	$3
52 - Outdoor Lighting Service	666	0.79%	$47
53 - Street Lighting Service	99	0.12%	$7
57 - Outdoor Lighting Service - EMU	435	0.51%	$30
58 - Outdoor Lighting Service - MU	11	0.01%	$1
59 - Outdoor Lighting Service - EM	11	0.01%	$1
37 - Penn State University	1	0.00%	$0
Total Commercial	**84,654**	**100.00%**	**$5,917**

Industrial			
20 - General Service	12,049	91.63%	$842
30 - General Power Service	883	6.71%	$62
40 - Primary Power Service	104	0.79%	$7
41 - Primary Power Service	3	0.02%	$0
44 - Interr Power Service	1	0.01%	$0
46 - Primary Power Service	2	0.02%	$0
51 - Street Lighting Service	13	0.10%	$1
52 - Outdoor Lighting Service	53	0.40%	$4
53 - Street Lighting Service	10	0.08%	$1
57 - Outdoor Lighting Service - EMU	26	0.20%	$2
58 - Outdoor Lighting Service - MU	1	0.01%	$0
59 - Outdoor Lighting Service - EM	1	0.01%	$0
86 - Alter. Gen. Rider	4	0.03%	$0
Total Industrial	**13,150**	**100.00%**	**$919**
Public St & Highway Lighting			
51 - Street Lighting Service	296	52.95%	$316
52 - Outdoor Lighting Service	1	0.18%	$1
53 - Street Lighting Service	1	0.18%	$1
54 - Street Lighting Service	55	9.84%	$59
55 - Street Lighting Service	5	0.89%	$5
56 - Street Lighting Service	3	0.54%	$3
57 - Street Lighting Service - EMU	193	34.53%	$206
58 - Street Lighting Service - MU	3	0.54%	$3
59 - Street Lighting Service - EM	1	0.18%	$1
71 - Street Lighting Service	1	0.18%	$1
Total Public St & Highway Lighting	**559**	**100.00%**	**$597**
Total	**717,894**		**$446,592**

West Penn Power Customer Accounting Total Account Dollars Assigned to Rate Group							
Rate	Meter Reading	Customer Records Collection	Uncollectible Accounts	Miscellaneous Customer Accounts	Forfeited Discounts and Miscellaneous Service Revenues	Cust Asst	MISC
Classes	**902**	**903**	**904**	**905**	**450 & 451**	**908**	**910**
Residentail							
10 - R - Residential	6,751,091	$7,659,902	$8,382,790	$108,513	($3,568,389)	$6,490,065	$436,209
20 - General Service	1,468	$1,058	$1,158	$15	($493)	-	$60
22 - Church & School	20	$12	$14	$0	($6)	-	$1
51 - Street Lighting Service	-	$25	$27	$0	($12)	-	$1
52 - Outdoor Lighting Service	-	$33,833	$37,026	$479	($15,761)	-	$1,927
53 - Street Lighting Service	-	$162	$177	$2	($75)	-	$9
57 - Outdoor Lighting Service - EMU	-	$16,692	$18,268	$236	($7,776)	-	$951
58 - Outdoor Lighting	-	$12	$14	$0	($6)	-	$1
59 - Outdoor Lighting - EM	-	$12	$14	$0	($6)	-	$1
Total Residential	**6,752,579**	**$7,711,709**	**$8,439,487**	**$109,246**	**($3,592,524)**	**$6,490,065**	**$439,159**
Commercial							
20 - General Service	1,386,917	$999,559	$1,093,891	$14,160	($465,648)	-	$5,613
22 - Church & School	26,895	$16,705	$18,281	$237	($7,782)	-	$94
23 - Athletic Field Service	464	$249	$272	$4	($116)	-	$1
24 - Fair & Carnival Service	164	$100	$109	$1	($46)	-	$1
30 - General Power Service	44,190	$21,111	$23,104	$299	($9,835)	-	$119
40 - Primary Power Service	395	$274	$300	$4	($128)	-	$2
51 - Street Lighting Service	-	$523	$572	$7	($244)	-	$3
52 - Outdoor Lighting Service	-	$8,290	$9,073	$117	($3,862)	-	$47
53 - Street Lighting Service	-	$1,232	$1,349	$17	($574)	-	$7
57 - Outdoor Lighting Service - EMU	-	$5,415	$5,926	$77	($2,522)	-	$30
58 - Outdoor Lighting Service - MU	-	$137	$150	$2	($64)	-	$1
59 - Outdoor Lighting Service - EM	-	$137	$150	$2	($64)	-	$1
37 - Penn State University	18	$12	$14	$0	($6)	-	$0
Total Commercial	**1,459,042**	**$1,053,744**	**$1,153,189**	**$14,928**	**($490,890)**	**-**	**$5,917**

Industrial							
20 - General Service	208,104	$149,982	$164,136	$2,125	($69,869)	-	$842
30 - General Power Service	23,007	$10,991	$12,029	$156	($5,120)	-	$62
40 - Primary Power Service	1,869	$1,295	$1,417	$18	($603)	-	$7
41 - Primary Power Service	54	$37	$41	$1	($17)	-	$0
44 - Interr Power Service	18	$12	$14	$0	($6)	-	$0
46 - Primary Power Service	36	$25	$27	$0	($12)	-	$0
51 - Street Lighting Service	-	$162	$177	$2	($75)	-	$1
52 - Outdoor Lighting Service	-	$660	$722	$9	($307)	-	$4
53 - Street Lighting Service	-	$124	$136	$2	($58)	-	$1
57 - Outdoor Lighting Service - EMU	-	$324	$354	$5	($151)	-	$2
58 - Outdoor Lighting Service - MU	-	$12	$14	$0	($6)	-	$0
59 - Outdoor Lighting Service - EM	-	$12	$14	$0	($6)	-	$0
86 - Alter. Gen. Rider	-	$50	$54	$1	($23)	-	$0
Total Industrial	**233,088**	**$163,687**	**$179,134**	**$2,319**	**($76,254)**	**-**	**$919**
Public St & Highway Lighting							
51 - Street Lighting Service	-	$3,685	$4,032	$52	($1,716)	-	$316
52 - Outdoor Lighting Service	-	$12	$14	$0	($6)	-	$1
53 - Street Lighting Service	-	$12	$14	$0	($6)	-	$1
54 - Street Lighting Service	-	$685	$749	$10	($319)	-	$59
55 - Street Lighting Service	-	$62	$68	$1	($29)	-	$5
56 - Street Lighting Service	-	$37	$41	$1	($17)	-	$3
57 - Street Lighting Service - EMU	-	$2,402	$2,629	$34	($1,119)	-	$206
58 - Street Lighting Service - MU	-	$37	$41	$1	($17)	-	$3
59 - Street Lighting Service - EM	-	$12	$14	$0	($6)	-	$1
71 - Street Lighting Service	-	$12	$14	$0	($6)	-	$1
Total Public St & Highway Lighting	**-**	**$6,958**	**$7,615**	**$99**	**($3,242)**	**-**	**$597**
Total	**8,444,691**	**$8,936,097**	**$9,779,425**	**$126,592**	**($4,162,909)**	**$6,490,065**	**$446,592**

Exhibit HES-2
Supporting Study No. 5
Labor

Metropolitan Edison Company
Cost of Service Study - Special Study #05
Direct Labor O&M Study

Function	FERC Account Number	O & M Expense Total	Direct Labor Expense	Percentage of Total w A&G
Power Supply				
Power Supply	514	3,357	0	
Power Supply	518	0	0	
Power Supply	555	278,084	0	
Power Supply	557	-5,707	0	
	TOTAL		**0**	**0.00%**
Transmission	560	58	18	
Transmission	561	1,208	137	
Transmission	562	174	0	
Transmission	563	33	0	
Transmission	564	0	0	
Transmission	565	11,776	0	
Transmission	566	1,198	198	
Transmission	567	472	0	
Transmission	568	920	669	
Transmission	570	2,650	1,934	
Transmission	571	2,347	0	
Transmission	573	93	0	
	TOTAL		**2,956**	**8.91%**
Distribution	580	97	84	
Distribution	581	339	274	
Distribution	582	615	397	
Distribution	583	37	0	
Distribution	584	576	0	
Distribution	585	0	0	
Distribution	586	771	561	
Distribution	588	4,949	3,712	
Distribution	590	390	248	
Distribution	591	16	8	
Distribution	592	4,043	2,430	
Distribution	593	20,233	5,286	
Distribution	594	2,048	1,343	
Distribution	595	0	0	
Distribution	596	250	161	
Distribution	597	1,645	1,235	
Distribution	598	1,428	980	
	TOTAL		**16,719**	**50.40%**

Metropolitan Edison Company
Cost of Service Study - Special Study #05
Direct Labor O&M Study

Function	FERC Account Number	O & M Expense Total	Direct Labor Expense	Percentage of Total w A&G
Customer Accounts			0	
Customer Accounts	902	5,026	3,645	
Customer Accounts	903	5,858	2,058	
Customer Accounts	904	12,136	0	
Customer Accounts	905	251	176	
	TOTAL		**5,879**	**17.72%**
Customer Service	907	304	271	
Customer Service	908	34,566	0	
Customer Service	909	130	0	
Customer Service	910	5,696	2,521	
	TOTAL		**2,793**	**8.42%**
A&G (Unfunctionalized)	920	-524	12	
A&G (Unfunctionalized)	921	3,155	0	
A&G (Unfunctionalized)	923	35,388	5,099	
A&G (Unfunctionalized)	924	242	0	
A&G (Unfunctionalized)	925	930	91	
A&G (Unfunctionalized)	926	-745	-374	
A&G (Unfunctionalized)	928	2,632	0	
A&G (Unfunctionalized)	930_1	10	0	
A&G (Unfunctionalized)	930_2	698	0	
A&G (Unfunctionalized)	931	1,612	0	
A&G (Unfunctionalized)	935	801	0	
	TOTAL		**4,827**	**14.55%**
TOTAL w/o A&G			**28,347**	
TOTAL w/ A&G			**33,174**	
% of Labor Transmission w/o A&G				**10.43%**

Pennsylvania Electric Company
Cost of Service Study - Special Study #05
Direct Labor O&M Study

Function	FERC Account Number	O&M Expense TOTAL	Direct Labor Expense	Percentage of Total w A&G
Power Supply				
Power Supply	514	210	0	
Power Supply	518	0	0	
Power Supply	555	342,136	0	
Power Supply	557	-36,077	0	
	TOTAL	**306,269**	**0**	**0.00%**
Transmission	560	70	20	
Transmission	561	1,568	393	
Transmission	562	0	0	
Transmission	563	356	0	
Transmission	564	0	0	
Transmission	565	10,219	0	
Transmission	566	944	196	
Transmission	567	2,760	0	
Transmission	568	1,144	833	
Transmission	570	544	237	
Transmission	571	6,694	0	
Transmission	573	0	0	
	TOTAL	**24,299**	**1,679**	**4.19%**
Distribution	580	104	60	
Distribution	581	434	393	
Distribution	582	0	0	
Distribution	583	53	0	
Distribution	584	839	0	
Distribution	585	0	0	
Distribution	586	648	411	
Distribution	588	8,070	4,160	
Distribution	590	438	279	
Distribution	591	0	0	
Distribution	592	7,621	4,501	
Distribution	593	20,771	10,914	
Distribution	594	52	0	
Distribution	595	0	0	
Distribution	596	1,662	1,179	
Distribution	597	1,496	1,039	
Distribution	598	1,377	906	
	TOTAL	**43,563**	**23,841**	**59.48%**

Pennsylvania Electric Company
Cost of Service Study - Special Study #05
Direct Labor O&M Study

Function	FERC Account Number	O&M Expense TOTAL	Direct Labor Expense	Percentage of Total w A&G
Customer Accounts				
Customer Accounts	902	5,028	3,883	
Customer Accounts	903	6,170	2,204	
Customer Accounts	904	8,959	0	
Customer Accounts	905	356	197	
	TOTAL	**26,351,000**	**6,284**	**15.68%**
Customer Service	907	263	231	
Customer Service	908	36,360	0	
Customer Service	909	120	0	
Customer Service	910	5,642	2,687	
	TOTAL	**42,385**	**2,918**	**7.28%**
A&G (Unfunctionalized)	920	-616	12	
A&G (Unfunctionalized)	921	1,644	0	
A&G (Unfunctionalized)	923	37,861	5,979	
A&G (Unfunctionalized)	924	315	0	
A&G (Unfunctionalized)	925	957	158	
A&G (Unfunctionalized)	926	2,757	-803	
A&G (Unfunctionalized)	928	2,378	0	
A&G (Unfunctionalized)	930	0	0	
A&G (Unfunctionalized)	930	0	0	
A&G (Unfunctionalized)	931	1,448	0	
A&G (Unfunctionalized)	935	224	16	
	TOTAL	**46,969**	**5,362**	**13.38%**
TOTAL w/o A&G		**26,767,516**	**34,722**	
TOTAL w/ A&G		**26,814,485**	**40,084**	
% of Labor Transmission w/o A&G				**4.84%**

Pennsylvania Power Company
Cost of Service Study - Special Study #05
Direct Labor O&M Study

Function	FERC Account Number	O&M Expense TOTAL	Direct Labor Expense	Percentage of Total w A&G
Power Supply				
Power Supply	514	0	0	
Power Supply	518	0	0	
Power Supply	555	75,519	0	
Power Supply	557	3	0	
	TOTAL	**75,522**	**0**	**0.00%**
Transmission	560	0	0	
Transmission	561	122	0	
Transmission	562	0	0	
Transmission	563	0	0	
Transmission	564	0	0	
Transmission	565	5,715	0	
Transmission	566	83	11	
Transmission	567	0	0	
Transmission	568	4	3	
Transmission	570	3	0	
Transmission	571	-11	-27	
Transmission	573	5	0	
	TOTAL	**5,921**	**-13**	**-0.15%**
Distribution	580	0	0	
Distribution	581	0	0	
Distribution	582	0	0	
Distribution	583	0	0	
Distribution	584	555	19	
Distribution	585	0	0	
Distribution	586	86	58	
Distribution	588	958	554	
Distribution	590	95	61	
Distribution	591	0	0	
Distribution	592	514	177	
Distribution	593	11,004	3,203	
Distribution	594	-15	0	
Distribution	595	0	0	
Distribution	596	1	0	
Distribution	597	379	343	
Distribution	598	345	202	
	TOTAL	**13,921**	**4,618**	**52.81%**

Pennsylvania Power Company
Cost of Service Study - Special Study #05
Direct Labor O&M Study

Function	FERC Account Number	O&M Expense TOTAL	Direct Labor Expense	Percentage of Total w A&G
Customer Accounts			0	
Customer Accounts	902	1,547	1,155	
Customer Accounts	903	1,626	548	
Customer Accounts	904	1,610	0	
Customer Accounts	905	39	26	
	TOTAL	**26,351,000**	**1,729**	**19.77%**
Customer Service	907	0	0	
Customer Service	908	9,957	151	
Customer Service	909	129	0	
Customer Service	910	1,498	0	
	TOTAL	**11,585**	**151**	**1.73%**
A&G (Unfunctionalized)	920	101	701	
A&G (Unfunctionalized)	921	489	0	
A&G (Unfunctionalized)	923	9,935	0	
A&G (Unfunctionalized)	924	26	96	
A&G (Unfunctionalized)	925	186	0	
A&G (Unfunctionalized)	926	94	1,458	
A&G (Unfunctionalized)	928	583	0	
A&G (Unfunctionalized)	930	0	0	
A&G (Unfunctionalized)	930	0	5	
A&G (Unfunctionalized)	931	347	0	
A&G (Unfunctionalized)	935	331	0	
	TOTAL	**12,092**	**2,259**	**25.84%**
TOTAL w/o A&G		**26,457,948**	**6,486**	
TOTAL w/ A&G		**26,470,041**	**8,745**	
% of Labor Transmission w/o A&G				**-0.20%**

West Pennsylvania Power Company
Cost of Service Study - Special Study #05
Direct Labor O&M Study

Function	FERC Account Number	O&M Expense TOTAL	Direct Labor Expense	Percentage of Total w A&G
Power Supply	514	0	0	
Power Supply	518	0	0	
Power Supply	555	333,711	0	
Power Supply	557	2	0	
	TOTAL	**333,713**	**0**	**0.00%**
Transmission	560	0	0	
Transmission	561	2,032	672	
Transmission	562	1,332	1,291	
Transmission	563	0	0	
Transmission	564	0	0	
Transmission	565	26,808	0	
Transmission	566	334	266	
Transmission	567	0	0	
Transmission	568	395	288	
Transmission	570	367	300	
Transmission	571	1,632	0	
Transmission	573	0	0	
	TOTAL	**32,899**	**2,818**	**7.41%**
Distribution	580	102	72	
Distribution	581	1,235	881	
Distribution	582	1,197	799	
Distribution	583	1,364	187	
Distribution	584	974	0	
Distribution	585	0	0	
Distribution	586	641	305	
Distribution	588	8,150	3,907	
Distribution	590	413	255	
Distribution	591	0	0	
Distribution	592	4,123	2,733	
Distribution	593	33,312	7,222	
Distribution	594	667	447	
Distribution	595	0	0	
Distribution	596	819	561	
Distribution	597	1,544	1,075	
Distribution	598	1,069	714	
	TOTAL	**55,610**	**19,159**	**50.40%**

West Pennsylvania Power Company
Cost of Service Study - Special Study #05
Direct Labor O&M Study

Function	FERC Account Number	O&M Expense TOTAL	Direct Labor Expense	Percentage of Total w A&G
Customer Accounts	902	11,080	7,460	
Customer Accounts	903	9,116	1,181	
Customer Accounts	904	10,642	0	
Customer Accounts	905	134	93	
	TOTAL	**26,351,000**	**8,734**	**22.98%**
Customer Service	907	574	498	
Customer Service	908	20,295	0	
Customer Service	909	53	0	
Customer Service	910	155	113	
	TOTAL	**21,077**	**611**	**1.61%**
A&G (Unfunctionalized)	920	-206	15	
A&G (Unfunctionalized)	921	1,906	0	
A&G (Unfunctionalized)	923	37,350	6,952	
A&G (Unfunctionalized)	924	296	0	
A&G (Unfunctionalized)	925	1,203	139	
A&G (Unfunctionalized)	926	5,596	-414	
A&G (Unfunctionalized)	928	2,467	0	
A&G (Unfunctionalized)	930	0	0	
A&G (Unfunctionalized)	930	0	0	
A&G (Unfunctionalized)	931	2,512	0	
A&G (Unfunctionalized)	935	771	0	
	TOTAL	**51,897**	**6,692**	**17.60%**
TOTAL w/o A&G		**26,794,298**	**31,322**	
TOTAL w/ A&G		**26,846,195**	**38,013**	
% of Labor Transmission w/o A&G				**9.00%**

Exhibit HES-2
Supporting Study No. 6
Meter Plant

Metropolitan Edison
Meter Plant Allocation

Rate Group	End of Period HTY Customer Count	Meter Count	Meter Cost	Meter Labor	PT/CT Cost & Labor	Total Cost	Total Cost per Customer	Weighting Factor	Weighted Customer Allocator
RS	448,405	449,699	10,815,249	6,064,690	73,943	16,953,882	37.81	1.0	448,405
RT	41,810	43,395	3,347,884	588,272	14,779	3,950,936	94.50	2.5	104,496
GSV	269	281	24,673	4,501	12,570	41,744	155.18	4.1	1,104
GSS	40,141	41,211	1,698,906	561,650	154,850	2,415,406	60.17	1.6	63,884
GSM	23,929	25,594	2,033,575	392,260	0	2,425,835	101.38	2.7	64,160
GSL	347	584	246,118	14,098	0	260,216	749.90	19.8	6,882
GP	498	643	243,611	31,331	2,176,055	2,450,996	4,921.68	130.2	64,825
MS	133	137	11,533	2,324	15,425	29,282	220.17	5.8	774
BRD	55	36	2,518	1,857	617	4,992	90.77	2.4	132
TP	23	36	24,911	1,902	651,539	678,352	29,493.56	780.1	17,941

Pennsylvania Electric Company
Meter Plant Allocation

Rate Group	End of Period HTY Customer Count	Meter Count	Meter Cost	Meter Labor	PT/CT Cost & Labor	Total Cost	Total Cost per Customer	Weighting Factor	Weighted Customer Allocator
RS	480,542	484,259	13,076,447	6,931,561	224,311	20,232,320	42.10	1.0	480,542
RT	19,736	20,648	1,871,332	284,135	24,206	2,179,674	110.44	2.6	51,770
GSV	675	696	48,990	9,952	13,382	72,324	107.15	2.5	1,718
GSS	52,471	54,843	2,169,226	757,116	216,552	3,142,895	59.90	1.4	74,648
GSM	28,597	30,712	2,529,151	459,937	1,774,461	4,763,549	166.58	4.0	113,140
GSL	415	690	302,362	16,870	68,015	387,246	933.12	22.2	9,198
GP	427	653	308,156	18,007	377,032	703,195	1,646.83	39.1	16,702
H	152	178	18,301	3,094	29,370	50,764	333.97	7.9	1,206
BRD	15	14	1,169	256	2,504	3,929	261.96	6.2	93
LP	49	81	36,601	2,241	140,762	179,604	3,665.39	87.1	4,266

Pennsylvania Power Company
Meter Plant Allocation

Rate Group	End of Period HTY Customer Count	Meter Count	Meter Cost	Meter Labor	PT/CT Cost & Labor	Total Cost	Total Cost per Customer	Weighting Factor	Weighted Customer Allocator
RS	122,820	130,537	4,233,345	1,771,890	6,106	6,011,340	48.94	1.2	150,223
RH	13,251	14,378	339,590	195,295	3,482	538,367	40.63	1.0	13,454
RSW	5,626	6,176	141,309	83,822	0	225,131	40.02	1.0	5,626
GSR	69	78	4,922	1,104	643	6,668	96.64	2.4	167
GS	17,511	18,023	1,095,528	250,664	210,298	1,556,490	88.89	2.2	38,896
GM	1,375	1,557	205,644	33,855	255,416	494,915	359.94	9.0	12,368
GP	110	142	87,230	3,778	310,653	401,661	3,651.46	91.2	10,037
OH	355	441	31,358	6,424	16,355	54,137	152.50	3.8	1,353
PNP	92	97	6,054	1,448	12,637	20,139	218.90	5.5	503
POL	830							-	-
STLT	86							-	-
GT	40	57	29,095	1,507	891,606	922,208	23,055.19	576.1	23,046

West Pennsylvania Power Company
Meter Plant Allocation

Rate Group	End of Period HTY Customer Count	Meter Count	Meter Cost	Meter Labor	PT/CT Cost & Labor	Total Cost	Total Cost per Customer	Weighting Factor	Weighted Customer Allocator
RS	617,508	616,774	16,844,180	8,318,231	39,199	25,201,610	40.81	1.0	617,508
GS10	522	531	35,018	8,345	21,580	64,943	124.41	3.0	1,591
GS20	91,880	92,201	3,514,144	1,000,159	2,124,813	6,639,116	72.26	1.8	162,676
GS22	1,326	1,345	75,686	20,622	49,837	146,145	110.22	2.7	3,581
GS23	20	20	21	2,142	445	2,608	130.39	3.2	64
GS24	9	9	433	126	57	616	68.40	1.7	15
GS30S	2,100	2,141	521,637	55,927	1,691,965	2,269,529	1,080.73	26.5	55,610
GS30L	516	568	289,402	15,310	1,734,893	2,039,605	3,952.72	96.9	49,976
POL	5,372	0	0	0	0	-		-	-
PSU	1	11	5,151	297	0	5,448	5,447.54	133.5	133
PP40	128	169	114,006	4,540	1,444,427	1,562,973	12,210.73	299.2	38,297
PP41	3	4	3,498	108	90,100	93,706	31,235.20	765.3	2,296
PP44	1	1	962	27	39,000	39,989	39,988.59	979.8	980
PP46	2	26	19,141	701	14,600	34,442	17,221.25	422.0	844
AGS	4	0	0	0	0	-		-	-
STLT	559	0	0	0	0	-		-	-

Exhibit HES-2
Supporting Study No. 7
Primary / Secondary and Minimum Grid

Pennsylvania Rate Case

Customer Component of

FERC Account 364 – POLES, TOWERS, AND FIXTURES

FERC Account 365 – OVERHEAD CONDUCTORS & DEVICES

FERC Account 367 – UNDERGROUND CONDUCTORS & DEVICES

FERC Account 368 – LINE TRANSFORMERS

Primary Customer/Secondary Customer Component of

FERC Account 364 – POLES, TOWERS, AND FIXTURES

FERC Account 365 – OVERHEAD CONDUCTORS & DEVICES

FERC Account 366 – UNDERGROUND CONDUIT

FERC Account 367 – UNDERGROUND CONDUCTORS & DEVICES

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SCOPE

This report looks at two concepts, the allocation of certain distribution plant accounts to a customer cost (aka "minimum grid") or demand costs, here after referred to as the Customer Cost Study, and the allocation of certain distribution costs to customers served as primary voltage accounts. NARUC describes the basics of Customer Costs Studies in their publication "Electric Utility Cost Allocation Manual[1]," but the basics of these studies are to serve the purpose of allocating utility costs and/or asset values to different classes of customers.

Customer Cost Study

The Customer Cost Study is designed to separate the asset values into component costs, as follows;

- Customer Related Costs
- Demand Related Costs
- Energy Related Costs

The costs of the distribution system are primarily impacted by demand and the number of customers, so this study serves the purpose of allocating utility costs and/or asset values to those two cost components[2]. The plant accounts considered in this study are:

- FERC Account 364 – POLES, TOWERS, AND FIXTURES
- FERC Account 365 – OVERHEAD CONDUCTORS & DEVICES
- FERC Account 367 – UNDERGROUND C ONDUCTORS & DEVICES
- FERC Account 368 – LINE TRANSFORMERS

Primary/Secondary Customer Cost Study

The primary/secondary customer cost study is aimed at determining the portion of the distribution assets that are used to serve primary voltage customers; for example, the distribution transformer, secondary conductor, and service conductor types of distribution plant are not used to serve these customers. Similarly some accounts have limited assets that are used to provide service to these primary service customers; the Primary/Secondary Customer Cost Study is designed to determine the extent of each of those accounts used by the Primary Voltage Customer[3]. The accounts considered in this study are:

- FERC Account 364 – POLES, TOWERS, AND FIXTURES
- FERC Account 365 – OVERHEAD CONDUCTORS & DEVICES

[1] National Association of Regulatory Utility Commissions (NARUC). *Electric Utility Cost Allocation Manual*, 1992.

[2] ibid, p. 21.

[3] ibid, p. 19.

- FERC Account 366 – UNDERGROUND CONDUIT
- FERC Account 367 – UNDERGROUND CONDUCTORS & DEVICES

DEFINTIONS AND TERMS

A number of large data bases house the information used in the preparation of this report. The following definitions and terms describe: those systems and applications, from which data was extracted; the software tools used to extract, analyze, and summarize that information; and finally references are provided to any external data sources used.

Company Computer Systems, Data and Processes

The Company has a number of computer systems that house data used for this study. As utilities have grown, so has the size and complexity of these systems leading to the need to use software tools like SQL queries to analyze data sets that can no-longer be effectively analyzed using common desktop tools like Excel.

CCS

The Company's CCS or "Customer Care System" is the customer accounting and billing system. With data contained in this system the Company is able to tell the type of customer; the customer's customer rate code. The GIS and CCS customer records are connected though connection object database keys, which enable the Company to determine where, on the geographically represented system, each customer, and customer type, is connected. The CCS is a sub-system of SAP (see SAP below).

CREWS

CREWS is FirstEnergy's work management system, used by the Operating Companies to perform engineering estimates for construction work.

GIS

The Company's GIS or "Geographical Information System" is the computer system providing a geographically referenced, asset database of the installed distribution plant information, including information on poles, primary conductors, fuses, transformers, and switches, and how those pieces of the electric distribution system are electrically interconnected from the substation to the customer. The GIS is used primarily for mapping and detailing the distribution system aiding engineering design, planning and troubleshooting tasks.

SAP

SAP[4] offers bundles of applications and services to enable companies to manage their businesses. These applications can include customer care systems (CCS), billing, financial, purchasing, inventory, and human resources functions.

Software Tools

SQL

Structured Query Language (SQL)[5] is a special programming language designed to manage and extract data held in a relational data base management system (RDBS), like Oracle, Sybase, MySQL, or, Microsoft SQL Server. Most of the Company's data bases, used for the preparation of this report, are Oracle RDBSs.

Brio

Hyperion Intelligence Designer, by Hyperion Solutions Corporation (now owned by Oracle), or BRIO, as it is known within the Company, is a general purpose SQL query and reporting tool that allow the Company to perform and produce Excel-like analysis and reports on data sets too large or complex to handle within Microsoft Excel.

Perl

Perl, by ActiveState[6], is a high-level, general-purpose, scripting language, typically operated in an interpreted (not compiled) form. Perl is used primarily as a tool to encapsulate and run raw SQL queries, and may be used to provide some additional summarization for the purposes of reporting.

External Data Sources

Handy-Whitman Index

The *Handy-Whitman Index of Public Utility Construction*[7] provides asset price indexes and the capital book value against a benchmark year. Handy-Whitman Index numbers serve as a yardstick to estimate the impact of fluctuations in the value of material and labor costs, allowing assets of a known age to be reflected in other years. Average prices and cost trends are used to develop the Handy-Whitman Index. This Index is commonly used by utilities and regulators in

[4] SAP, www.sap.com.

[5] ISO/IEC 9075-1:2011, *Information technology -- Database languages -- SQL -- Part 1: Framework (SQL/Framework)*,

[6] ActiveState, www.activestate.com.

[7] *Handy-Whitman Index of Public Utility Construction*, Whitman, Requardt and Associates, LLP, 801 South Caroline Street, Baltimore, MD 21231,

their calculations of rate base for rate cases and in their valuations of property for insurance purposes.

Electric Utility Cost Allocation Manual[8]

The Electric Utility Cost Allocation Manual, by NARUC**,** was written by a team of utility, public utility commission, and FERC representatives and provides frameworks for costs of service studies. Section II of this Manual contains five chapters that explain the dominant method of cost allocation - the embedded cost study, which is based upon historical or known utility costs. Areas covered are production costs, transmission costs, distribution costs and the classification and allocation of customer-related costs and investments.

[8] National Association of Regulatory Utility Commissions (NARUC). *Electric Utility Cost Allocation Manual*, 1992.

FERC Account 364 – POLES, TOWERS, AND FIXTURES

This plant distribution account is predominately made up of the various wood distribution poles used to support primary and secondary distribution conductors.

Assumptions and Method

- The Company's GIS was used to determine the number of wood distribution poles, by size and install year. In the analysis, these poles were replaced by the minimum size wood distribution poles that have seen common use within the study territory; 35-foot poles for those supporting primary conductors without joint use underbuild.
    - Poles without an install year were omitted
    - Poles with install years < 1914 were omitted
    - Only poles supporting primary conductor were included (i.e., street-light and secondary only poles were omitted).
    - Only poles where POLE_MAT in (D, L, M, N, P, R, W, Z) were considered … the other materials are fiberglass, steel, concrete, aluminum, etc. materials that are unlikely for "distribution" poles.
    - Only poles where HEIGHT in (25, 30, 35, 40, 45, 50, 55, 60, 65, 70, 75, 80, 85, 90, & 95) were considered, the other pole heights typically indicate either street-light only poles, i.e., HEIGHT in (12, 15, 16, 17, 20, 27) or may reflect erroneous data.
- The current installed cost for each size pole was obtained from CREWS, and trended by size to build a list of costs by pole length for each size wood pole.
- The install years were used to age the current costs for the actual size and minimum size transformers using Handy-Whitman indices, and extended by the number of poles in service for each year, then summed to develop the customer component for this plant account.
- The percentage of minimum size cost (Customer Cost), of the Total Plant Value was calculated as the portion represented by the cost of the minimum sized units, 35 foot poles, as previously defined. The percentage of the demand costs for the account is the remainder, after the customer cost component was removed.
- This study was repeated for each Operating Company.

FERC Account 364 POLES, TOWERS, AND FIXTURES SPLIT OF PLANT					
Company	Total Plant Value	Customer Costs		Demand Costs	
		Percent	Value	Percent	Value
Met-Ed	$346,857,645[9]	78.0%	$270,396,603	22.0%	$76,461,042
Penelec	$475,757,653[10]	79.0%	$375,702,485	21.0%	$100,055,168
PennPower	$94,038,905[11]	84.5%	$79,444,370	15.5%	$14,594,535
West Penn Power	$323,422,350[12]	85.6%	$276,947,117	14.4%	$46,475,233

[9] Per Metropolitan Edison Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 364, Balance at End of Year, pg. 207.

[10] Per Pennsylvania Electric Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 364, Balance at End of Year, pg. 207.

[11] Per Pennsylvania Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 364, Balance at End of Year, pg. 207.

[12] Per West Penn Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 364, Balance at End of Year, pg. 207.

FERC Account 365 - OVERHEAD CONDUCTORS AND DEVICES

This plant distribution account is predominately made up of the various overhead distribution line conductors, operating at either primary or secondary voltage. This study considered primary conductors only, the Company's GIS data is not sufficient to perform a similar analysis on the costs of secondary, service, and/or street-light conductors. The Company's GIS data is not sufficient to perform a Handy-Whitman analysis of the install date for primary conductors.

Assumptions and Method

- The Company's GIS was used to determine the wire miles of overhead distribution primary distribution line conductors, by size. These conductors were categorized into and two sizes, large and small.
  - Conductors with a blank or unknown conductor type/size were omitted
- The current installed cost for each category of primary line conductor was obtained and used to cost out the currently installed system, if rebuilt using one of those two sizes.
- The minimum grid cost was developed using only the cost of the smaller conductor.
- The percentage of minimum size cost (Customer Cost), of the Total Plant Value was calculated as the portion represented by the cost of the system, built with the minimum sized conductor.

FERC Account 365
OVERHEAD CONDUCTORS AND DEVICES
SPLIT OF PLANT

Company	Total Plant Value	Customer Costs		Demand Costs	
		Percent	Value	Percent	Value
Met-Ed	$494,129,448[13]	84.1%	$415,665,486	15.9%	$78,463,962
Penelec	$768,055,055[14]	85.6%	$657,367,243	14.4%	$110,687,812
PennPower	$133,531,965[15]	91.1%	$121,703,672	8.9%	$11,828,290
West Penn Power	$439,672,546[16]	93.1%	$409,199,212	6.9%	$30,473,334

[13] Per Metropolitan Edison Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 365, Balance at End of Year, pg. 207.

[14] Per Pennsylvania Electric Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 365, Balance at End of Year, pg. 207.

[15] Per Pennsylvania Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 365, Balance at End of Year, pg. 207.

FERC Account 367 - UNDERGROUND CONDUCTORS AND DEVICES

This plant distribution account is predominately made up of the various underground distribution line conductors, operating at either primary or secondary voltage. This study considered primary conductors only, the Company's GIS data is not sufficient to perform a similar analysis on the costs of secondary and/or service conductors.

Assumptions and Method

- The Company's GIS was used to determine the wire miles of underground distribution primary distribution line conductors, by size. These conductors were categorized into and two sizes, large and small.
    - Conductors with a blank or unknown conductor type/size were omitted
    - Conductor segments greater than 2,500' were considered data errors and omitted
- The current installed cost for each category of primary line conductor was obtained and used to cost out the currently installed system, if rebuilt using one of those two sizes.
- The minimum grid cost was developed using only the cost of the smaller conductor.
- The percentage of minimum size cost (Customer Cost), of the Total Plan Value was calculated as the portion represented by the cost of the system, built with the minimum sized conductor.

[16] Per West Penn Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 365, Balance at End of Year, pg. 207.

FERC Account 367 UNDERGROUND CONDUCTORS AND DEVICES SPLIT OF PLANT					
Company	Total Plant Value	Customer Costs		Demand Costs	
		Percent	Value	Percent	Value
Met-Ed	$201,130,561[17]	88.4%	$177,717,518	11.6%	$23,413,043
Penelec	$149,308,187[18]	79.7%	$119,060,736	20.3%	$30,247,451
PennPower	$54,917,890[19]	82.3%	$45,176,533	17.7%	$9,741,357
West Penn Power	$128,876,860[20]	85.6%	$110,285,383	14.4%	$18,591,477

[17] Per Metropolitan Edison Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 367, Balance at End of Year, pg. 207.

[18] Per Pennsylvania Electric Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 367, Balance at End of Year, pg. 207.

[19] Per Pennsylvania Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 367, Balance at End of Year, pg. 207.

[20] Per West Penn Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 367, Balance at End of Year, pg. 207.

FERC Account 368 - LINE TRANSFORMERS

This plant distribution account is predominately made up of the various distribution transformers used to step the distribution voltage down to the service-voltage level delivered to the customer. This account includes both overhead and pad-mounted transformers.

Assumptions and Method

- The Company's GIS system was used to determine the number of overhead and pad-mounted distribution transformers, by size and install year, to be replaced by the minimum size (25 KVA) overhead line transformer that is in common use within the study territory.
- The current installed cost for each size line transformer was obtained from CREWS, and trended by size to build a list of costs by size for each size overhead and pad-mounted distribution transformer.
- The install years were used to age the current costs for the actual size and minimum size transformers using Handy-Whitman indices, and extended by the number of transformers in service for each year, then summed to develop the customer component for this plant account.
- Transformers missing install year, construction type, or kVA were omitted.
- The percentage of minimum size cost, of the calculated current cost was calculated as the portion represented by the cost of the minimum sized units.

FERC Account 368 LINE TRANSFOMERS SPLIT OF PLANT					
Company	Total Plant Value	Customer Costs		Demand Costs	
		Percent	Value	Percent	Value
Met-Ed	$391,129,266	56.7%	$221,712,856	43.3%	$169,416,410
Penelec	$357,011,042	68.2%	$243,603,491	31.8%	$113,407,551
PennPower	$97,338,801	66.6%	$64,795,623	33.4%	$32,543,178
West Penn Power	$346,431,279	77.1%	$267,190,838	22.9%	$79,240,441

FERC Account 364 – POLES, TOWERS, AND FIXTURES

This plant distribution account is predominately made up of the various wood distribution poles used to support primary and secondary distribution conductors.

Assumptions and Method

Using data from the Company's GIS, the wood pole plant was separated by poles which have both primary and secondary attached facilities, poles with secondary attached facilities, poles with secondary attached facilities and wood poles with street-lighting facilities. To divide up the value of the account, the raw pole counts were calculated as well as a weighting based upon the cost to install a pole in today dollars.

The Company's pole data allows for the identification of the total wood poles plant, and wood poles with primary facilities attached, but does not allow for the identification of poles with private-outdoor lighting facilities, street-light facilities or secondary facilities. The poles serving primary service customers are allocated to primary rate customers, all other poles will need to be split between all rate classes, except primary service customers.

A list of primary accounts was extracted from the CCS and used as the starting point for traces in the GIS system. From these traces in GIS, for each of the primary accounts and their associated Connection Object were reviewed to determine if multiple primary customers shared primary circuit routes to ensure facilities allocated to primary rate customers were only counted once.

- Only poles supporting primary and secondary conductor were included (i.e., street-light only poles were omitted).
- Only poles where POLE_MAT in (D, L, M, N, P, R, W, Z) were considered … the other materials are fiberglass, steel, concrete, aluminum, etc. materials that are unlikely for "distribution" poles.
- Only poles where HEIGHT in (15, 20, 25, 30, 35, 40, 45, 50, 55, 60, 65, 70, 75, 80, 85, 90, & 95) were considered, the other pole heights typically indicate either street-light only poles, i.e., HEIGHT in (12, 15, 16, 17, 20, 27) or may reflect erroneous data.

FERC Account 364 POLES, TOWERS, AND FIXTURES SPLIT OF PLANT					
Company	Total Plant Value	Primary Customers		Secondary and Street Light Customers	
		Percent	Value	Percent	Value
Met-Ed	$346,857,645[21]	5.4%	$18,616,460	94.6%	$328,241,185
Penelec	$475,757,653[22]	6.0%	$28,467,269	94.0%	$447,290,384
PennPower	$94,038,905[23]	3.2%	$3,039,423	96.8%	$90,999,482
West Penn Power	$323,422,350[24]	0.5%	$1,657,663	99.5%	$321,764,687

When a device or structure serves multiple primary customers, it is only counted one time in the results. See Figure 1 for a simplified graphical.

[21] Per Metropolitan Edison Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 364, Balance at End of Year, pg. 207.

[22] Per Pennsylvania Electric Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 364, Balance at End of Year, pg. 207.

[23] Per Pennsylvania Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 364, Balance at End of Year, pg. 207.

[24] Per West Penn Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 364, Balance at End of Year, pg. 207.

FERC Account 365 – OVERHEAD CONDUCTORS & DEVICES

This plant distribution account is predominately made up of the various overhead distribution line conductors, operating at either primary or secondary voltage. This study considered primary conductors only, the Company's GIS data is not sufficient to perform a similar analysis on the costs of secondary and/or service conductors.

Assumptions and Method

The primary conductors are allocated to both primary and secondary rates. To simplify the summations the conductors were divided into two sizes: large and small. The unique conductor paths, avoiding the duplicate counting of conductors, were calculated for all the primary customers back to the breaker on each circuit. The primary conductors were separated into small and large size conductors.

The conductor length of unique primary conductor feet is obtained by obtaining the span length of each primary line segment and then, by segment, multiplying by the number of conductors, and summing to obtain the total primary conductor feet used to serve primary customers. The same process is used for determining the total conductor feet for all primary conductors in the system.

A weighting is then used to account for the differences in cost to install a foot of large vs. small conductor. The weighted conductor length for primary conductors feeding primary rate customers is then compared to the weighted total conductor length of all conductors to obtain the percentage of primary conductor used by the primary rate customers.

FERC Account 365 OVERHEAD CONDUCTORS AND DEVICES SPLIT OF PLANT					
Company	Total Plant Value	Primary Customers		Secondary Customers	
		Percent	Value	Percent	Value
Met-Ed	$494,129,448[25]	11.0%	$54,225,199	89.0%	$439,904,249
Penelec	$768,055,055[26]	9.9%	$75,978,791	90.1%	$692,076,264
PennPower	$133,531,965[27]	12.8%	$17,088,420	87.2%	$116,443,545
West Penn Power	$439,672,546[28]	1.2%	$5,277,066	98.8%	$434,395,480

When a device or structure serves multiple primary customers, it is only counted one time in the results. See Figure 1 for a simplified graphical.

[25] Per Metropolitan Edison Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 365, Balance at End of Year, pg. 207.

[26] Per Pennsylvania Electric Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 365, Balance at End of Year, pg. 207.

[27] Per Pennsylvania Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 365, Balance at End of Year, pg. 207.

[28] Per West Penn Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 365, Balance at End of Year, pg. 207.

FERC Account 367 – UNDERGROUND CONDUCTORS & DEVICES

This plant distribution account is predominately made up of the various underground distribution line conductors, operating at either primary or secondary voltage. This study considered primary conductors only, the Company's GIS data is not sufficient to perform a similar analysis on the costs of secondary and/or service conductors.

Assumptions and Method

The primary conductors are allocated to both primary and secondary rates. To simplify the summations the conductors were divided into two sizes: large and small. The unique conductor paths, avoiding the duplicate counting of conductors, were calculated for all the primary customers back to the breaker on each circuit. The primary conductors were separated into small and large size conductors.

- Conductors with a blank or unknown conductor type/size were omitted
- Conductor segments greater than 2,500' were considered data errors and omitted

The conductor length of unique primary conductor feet is obtained by obtaining the span length of each primary line segment and then, by segment, multiplying by the number of conductors, and summing to obtain the total primary conductor feet used to serve primary customers. The same process is used for determining the total conductor feet for all primary conductors in the system.

A weighting is then used to account for the differences in cost to install a foot of large vs. small conductor. The weighted conductor length for primary conductors feeding primary rate customers is then compared to the weighted total conductor length of all conductors to obtain the percentage of primary conductor used by the primary rate customers.

FERC Account 367 UNDERGROUND CONDUCTORS AND DEVICES SPLIT OF PLANT					
Company	Total Plant Value	Primary Customers		Secondary Customers	
		Percent	Value	Percent	Value
Met-Ed	$201,130,561[29]	8.9%	$17,852,958	91.1%	$183,277,603
Penelec	$149,308,187[30]	4.5%	$6,733,754	95.5%	$142,574,433
PennPower	$54,917,890[31]	2.2%	$1,213,117	97.8%	$53,704,773
West Penn Power	$128,876,860[32]	0.9%	$1,193,379	99.1%	$127,683,481

When a device or structure serves multiple primary customers, it is only counted one time in the results. See Figure 1 for a simplified graphical.

[29] Per Metropolitan Edison Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 367, Balance at End of Year, pg. 207.

[30] Per Pennsylvania Electric Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 367, Balance at End of Year, pg. 207.

[31] Per Pennsylvania Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 367, Balance at End of Year, pg. 207.

[32] Per West Penn Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 367, Balance at End of Year, pg. 207.

FERC Account 366 – UNDERGROUND CONDUIT

Conduit systems are used to supply both the primary rate and secondary rate customers. The majority of the conduit system is used to protect primary cable (which can be used to serve both primary customers, and secondary customers via transformation), and of that majority, the bulk of the primary conduit system is installed to protect large primary cables. Said another way, where majority of the large-sized primary cables are installed in conduit, and the majority of the small-sized primary cables are direct buried. The majority of secondary cables are direct buried.

Assumptions and Method

The circuit length of unique large sized, underground primary conductor feet is obtained by obtaining the span length of each primary line segment, and summing to obtain the total primary circuit feet used to serve primary customers. The same process is used for determining the total circuit feet for all large primary conductors in the system.

- Conductors with a blank or unknown conductor type/size were omitted
- Conductor segments greater than 2,500' were considered data errors and omitted

The circuit length for large primary conductors, serving primary rate customers, is then compared to the total large primary circuit length to obtain the percentage of conduit systems used by the primary rate customers.

FERC Account 365 OVERHEAD CONDUCTORS AND DEVICES SPLIT OF PLANT					
Company	Total Plant Value	Primary Customers		Secondary Customers	
		Percent	Value	Percent	Value
Met-Ed	$494,129,448[33]	22.7%	$6,864,314	77.3%	$23,420,557
Penelec	$768,055,055[34]	11.0%	$4,004,614	89.0%	$32,491,580
PennPower	$133,531,965[35]	4.7%	$328,017	95.3%	$6,642,162
West Penn Power	$439,672,546[36]	0.9%	$186,415	99.1%	$20,828,845

[33] Per Metropolitan Edison Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 366, Balance at End of Year, pg. 207.

[34] Per Pennsylvania Electric Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 366, Balance at End of Year, pg. 207.

[35] Per Pennsylvania Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 366, Balance at End of Year, pg. 207.

[36] Per West Penn Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 366, Balance at End of Year, pg. 207.

When a device or structure serves multiple primary customers, it is only counted one time in the results. See Figure 1 for a simplified graphical.

Figure 1 – Primary Customer Connection & Routing

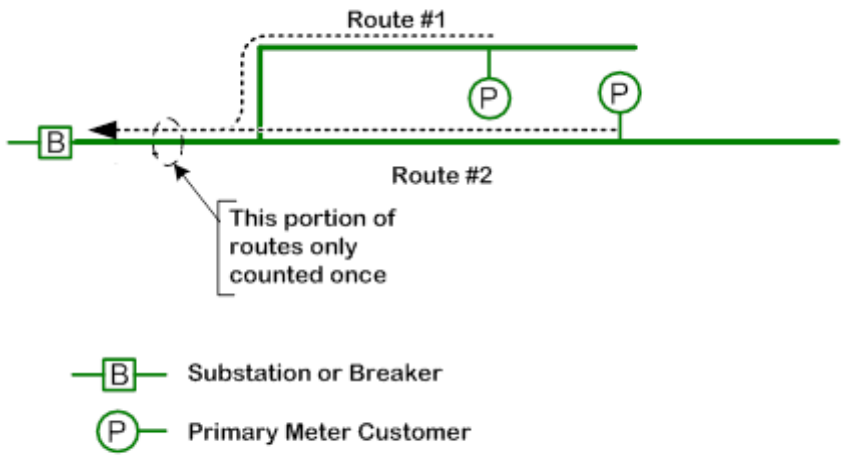


Exhibit HES-2
Supporting Study No. 8
Streetlighting Poles

Streetlights

FERC Account 364 – POLES, TOWERS, AND FIXTURES

FERC Account 364 – POLES, TOWERS, AND FIXTURES

This plant distribution account is predominately made up of the various wood distribution poles used to support primary and secondary distribution conductors.

Assumptions and Method

- The Company's GIS was used to determine the number of street lights on distribution poles, by size and install year of the pole.
  - The count of poles does not identify if the pole is used for anything other than streetlights. (i.e. distribution primary or secondary conductors)
  - Streetlights attached to joint use poles were not included.
- The current installed cost for each size pole was obtained from CREWS, and trended by size to build a list of costs by pole length for each size wood pole.
- The install years were used to age the current costs for the actual size poles using Handy-Whitman indices, and extended by the number of poles in service for each year, then summed to develop the streetlight component for this plant account.
- This study was repeated for each Operating Company.

Company	Total Plant Value	Streetlight Costs	
		Percent	Value
Met-Ed	$346,857,645[1]	3.0%	$10,469,426
Penelec	$475,757,653[2]	1.3%	$6,207,726
PennPower	$94,038,905[3]	4.8%	$4,485,972
West Penn Power	$323,422,350[4]	2.8%	$14,976,450

[1] Per Metropolitan Edison Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 364, Balance at End of Year, pg. 207.

[2] Per Pennsylvania Electric Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 364, Balance at End of Year, pg. 207.

[3] Per Pennsylvania Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 364, Balance at End of Year, pg. 207.

[4] Per West Penn Power Company, FERC Form No. 1, Year/Period of Report, End of 2013/Q4, Account 364, Balance at End of Year, pg. 207.

Exhibit HES-2
Supporting Study No. 9
Other Revenues

Met-Ed Acct 450 to 456 Revenues

FERC	Cost Element	Description	Total Company	Power Supply	Distribution	Other Trans.	Stranded Costs
945000	450000	**Forfeited Discount**	(3,229,377)	-	(3,229,377)	-	-
945100	451000	Misc Service	(1,850,108)		(1,850,108)		
945100	451009	Misc Service - ME PA Est Reg	(52,400)		(52,400)		
945100		**Total Revenue Miscellaneous Service**					
945400	454000	Merrill Creek	-		-		-
945400	454000	Rent from Electric Property	(1,655,620)		(1,655,620)		
945400	454009	Rent from Elec Prop - ME01 PA Est Reg (Pole Attac	(7,848,157)		(7,848,157)		
945400	454203	Lease/Rental Income - Assoc Cos - Trans Lines & Ir	(6,058,572)			(6,058,572)	
945400	454204	Lease/Rental Income - Building Assoc Cos	(3,914,687)	-	(3,914,687)	-	-
945400		**Total Revenue - Rent from Electric Property**					
945600	456000	Revenues - Transmission (Wheeling)	(14,520)			(14,520)	
945600	456029	Misc other rev	(229,105)			(229,105)	
945600	456122	Sale of scrap	(42,927)		(42,927)		
		Total Revenues - Other Electric Revenues					
945610	456005	PJM - ARR rev	(302,302)	(302,302)			
945610	456078	Rev-Oth Elec-Pjm Non-Firm Pt to Pt Transm Srv	(5,416)	(5,416)			
945610	456081	PJM NTS	(44,818,249)			(44,818,249)	
945610	456082	PJM NTS contra	2,040,000	2,040,000			
945610	456083	Pt to Pt xmission	(385,992)			(385,992)	
945610	456084	AEC wheeling rev & NTS	(2,222,916)			(2,222,916)	
945610	456100	Ancillary services revenue	(1,674,887)			(1,674,887)	
945610		**Total Revs from Transmission of Elec. of Others**					-
		Total Other Revenue	(72,265,235)	1,732,282	(18,593,276)	(55,404,241)	-

Penelec Acct 450 to 454 Revenues

Acct	Description	Total Company	Power Supply	Distribution	TSC Charges	Other Trans.	Waverly
450000	Forfeited Discount	3,423,516		3,409,822			13,694
							-
							-
451 Accounts							-
451000	Misc Service	1,436,028		1,430,284			5,744
451001	Misc Service - OE Cnt Reg	-		-			-
451003	Misc Service - OE Wst Reg	-		-			-
451005	Misc Service - CE01 OH Nth Reg	-		-			-
451008	Misc Service - PP OH Est Reg	-		-			-
451009	Misc Service - ME Est Reg	-		-			-
451010	Misc Service - PN PA Wst Reg	170,096		169,415			680
451011	Misc Service - NJ Nth Reg	-		-			-
451012	Misc Service - JC01 NJ Nth Reg	-		-			-
451100	Misc Service - Temp Fac Clrg - Power Plant Only	-		-			-
451130	Misc Service - Profit Cont Aid Cons - PN01 PA Wst Reg	46,992		46,804			188
835088	Proj Misc Services Rev Settl-Ext-Type 22	-		-			-
Total of 451 Accounts		1,653,116		1,646,503			6,612
							-
							-
454 Accounts							-
454000	Rent from Electric Property- telephone rental	1,296,432		1,291,246			5,186
454010	Rent from Elec Prop - PN01 PA West Reg	5,088,984		5,068,628			20,356
454097	Oth Rental - Assoc Co -- PN ROW Rev	-		-			-
454099	Rent from Elec Prop - Assoc Cos	-		-			-
454126	Rent from Prop - Elec Prop - Land & Bldg	-		-			-
454203	Lease/Rental Income - Assoc Cos - Trans Lines & Inter	22,020		-		22,020	-
454203	NYPA Wheeling Charges	-		-		-	-
454203	Seneca Trans Costs	-	-	-	-	-	-
Total of 454 Accounts		6,407,436	-	6,359,874	-	22,020	25,542
Total 450-451-454		11,484,068	-	11,416,199	-	22,020	45,848

Penelec Acct 456 Revenues

Acct	Description	Power Supply	Distribution	Transmission	Other Trans.	Stranded Costs	Waverly
456000	AEC wheeling NITS		75,381		-		303
456003	Island Rentals			-			
456005	ARR rev	198,898		-			1,381.93
456006	Congestion credit			-			
456008	Ancil serv rev				-		
456020	other wheeling rev				-		
456030	Other elec rev		533,394				2,142
456050	Other Rev - Sale of Obsolete Inventory		-				
456078	PJM Non-firm Pt to Pt Trans Srv	3,375					23
456081	PJM NTS				45,621,873		
456082	PJM NTS contra	(1,251,306)		-			(8,694)
456083	Pt to Pt xmission				874,668		
456084	AEC wheeling rev & NTS				5,851,512		
456100	Ancillary Service - Revenue				1,099,378		
456122	Sale of scrap		46,804				188
456268	Assoc co - outside serv		-				
456278	Other Revenues - TMI Strike Price Pmt	-	-	-	-	-	-
	Total other revenue accts	(1,049,033)	655,579	-	53,447,431	-	(4,656)

Penn Power Acct 450 to 454 Revenues

Acct	Description	Total Company	Power Supply	Distribution	TSC Charges	Other Trans.	Stranded Costs
450000	Forfeited Discount	1,290,912		1,290,912			
451 Accounts							
451000	Misc Service	168,572		168,572			
451001	Misc Service -OE01 OH Cnt Reg	-		-			
451003	Misc Service -OE01 OH Wst Reg	-		-			
451008	Misc Service - PP01 Oh Est Reg	25,801		25,801			
451009	Misc Service -ME01 PA Est Reg	-		-			
451010	Misc Service - PN01 PA Wst Reg	-		-			
451012	Misc Service - JC01 PA Nth Reg	-		-			
451100	Misc Service - Temp Fac Clrgs- Powerplant Only	-		-			
451100	Revenues Misc Serv MP01	-		-			
Total of 451 Accounts		194,373		194,373			
454 Accounts							
454000	Rent from Electric Property	121,815		121,815			
454001	Rent from Elec Prop - PP01 OH Cnt Reg	-					
454008	Rent from Elec Prop - PP01 OH Est Reg	(12)		(12)			
454126	Rent from Prop - Elec Prop - Land & Bldg	-		-			
Total of 454 Accounts		121,803	-	121,803	-	-	-
Total 450-451-454		1,607,088	-	1,607,088	-	-	-

Penn Power Acct 456 Revenues

Acct	Description	Power Supply	Distribution	Transmission	Other Trans.	Stranded Costs
456005	PJM ARR Revenue	3,249				
456006	PJM Congestion Credit -FTR	-				
456020	Rev other Electric	89,400			-	
456028	Other elec rev-PP01 OH Est Reg		-			
456050	Revenues -- Other Electric-Sale of Obsolete Inventory	-	-			
456089	MISO FTR/ARR Revenue	-			-	
456097	Revenues -- ATSI Ground Lease - Assoc Co	-	1,315,932		-	
456112	Other Rev Other	-	-			
456122	Sale of Scrap	-	-			
456255	Telecom-Rent-Wireless Leases	-	-			
456268	Assoc co - outside serv	-	-			
456078	Rev-Oth Elec-PJM Non-Firm Point to Point Trnsm Srv	2,597				
		-	-	-	-	-
	Total other revenue accts	95,246	1,315,932	-	-	-

West Penn Power Acct 450 to 454 Revenues

Acct	Description	Total Company	Power Supply	Distribution	TSC Charges	Other Trans.
450000	Forfeited Discount	(3,000,000)		(3,000,000)		
451 Accounts						
451000	Misc Service	(1,877,000)		(1,877,000)		
451001	Misc Service - OE Cnt Reg	-		-		
451009	Misc Service - ME Est Reg	-		-		
451010	Misc Service - PN PA Wst Reg	-		-		
451144	Misc Service - WP01	(74,364)		(74,364)		
Total of 451 Accounts		(1,951,364)		(1,951,364)		
454 Accounts						
454000	Rent from Electric Property	(617,831)		(617,831)		
454126	Rent from Prop - Elec Prop - Land & Bldg	-		-		
454204	Lease/Rental Income - Buildings - Assoc cos	(9,400,716)	-	(9,400,716)	-	
Total of 454 Accounts		(10,018,547)	-	(10,018,547)	-	-
Total 450-451-454		(14,969,911)	-	(14,969,911)	-	-

Exhibit HES-2

Supporting Study No. 10

Line Losses

The attached schedule supporting the Company's line loss factors is:

Met-Ed, Penelec, and Penn Power: Section 6.3 (page 24)

West Penn Power: Company Line Loss Factor Rider (page 57)

of the Company's Supplier Tariff, on file with the Pennsylvania Public Utility Commission.

Met-Ed

6.3 Line Losses. For purposes of EGS load calculations in Sections 6 and 7 of this Supplier Coordination Tariff, the combined transmission and distribution line losses shall be calculated by multiplying hourly kWh sales delivered to Customer(s) served pursuant to the specified rates by the applicable line loss factor. The applicable line loss factors are:

LOSS FACTORS

ENERGY	MET-ED
Rate Schedule TP	1.0210
GP	1.0374
All other rate schedules	1.0718

The Company reserves the right to file to revise these factors from time to time to reflect changes in system line losses.

Penelec

6.3 Line Losses. For purposes of EGS load calculations in Sections 6 and 7 of this Supplier Coordination Tariff, the combined transmission and distribution line losses shall be calculated by multiplying hourly kWh sales delivered to Customer(s) served pursuant to the specified rates by the applicable line loss factor. The applicable line loss factors are:

LOSS FACTORS

ENERGY	PENELEC
Rate Schedule LP	1.0407
GP	1.0606
All other rate schedules	1.0945

The Company reserves the right to file to revise these factors from time to time to reflect changes in system line losses.

Penn Power

6.3 Distribution Real Power Losses for Energy. Losses will be calculated by multiplying the retail Customer(s) load times the applicable real power loss factor specified below:

Service Voltage Level	Cumulative Loss Factor
23 kV to < 69 kV	0.1%
4.1 kV to < 23 kV	3.0%
4.1 kV	6.2%

The Company will revise these line loss factors if PJM imposes or changes any separate charges on its transmission Customers for the level of line losses that is included in these factors. Any such revision will be filed with the FERC and the Commission, provided to EGSs via electronic mail and posting on the Company's website, and become effective thirty (30) days after filing unless otherwise ordered by the Commission or the FERC (or concurrently with any change in or imposition of separate PJM line loss charges, whichever is later). The Company will make a good faith effort to advise EGSs of any change in these loss factors more than thirty (30) days in advance of a change when warranted.

West Penn

WEST PENN POWER COMPANY

COMPANY LINE LOSS FACTOR RIDER

For purposes of calculating daily load estimates and energy reconciliation in Rules 6, 7 and 8 of the EGS Tariff, the combined real power transmission losses and distribution line losses for Secondary, Primary, Subtransmission with transformer charges, Subtransmission and Transmission voltage levels shall be calculated by multiplying hourly kWh sales delivered to Customer(s) served at these voltage levels by the applicable line loss factor. Line loss factors are time-differentiated as on-peak and off-peak for each voltage classification. The on-peak line loss factors apply to the hours ended 8 a.m. to 11 p.m. Monday through Saturday. The off-peak line loss factors apply to all remaining hours. The applicable on-peak and off-peak line loss factors are:

Voltage served	On-peak line losses	Off-peak line losses
Secondary	9.434%	8.537%
Primary	6.383	5.482
Subtransmission w/ transformer charges	4.282	3.992
Subtransmission	3.578	3.277
Transmission	2.184	1.938

The Company will make available the mapping of the voltage line loss factors to the respective EDC Tariff rate schedules and rate codes on the Company website. The Company reserves the right to file to revise these factors from time to time to reflect changes in system line losses. Any such revision will be filed with the FERC (if required) and the PUC, provided to Registered EGSs via Internet electronic mail and posted on the Company's website, and become effective thirty (30) days after filing unless otherwise ordered by the PUC or the FERC. The Company will make a good faith effort to advise Registered EGSs of any change in these line loss factors more than thirty (30) days in advance of a change when warranted.

Met-Ed/Penelec/Penn Power/West Penn
Statement No. 9

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2014-2428745

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. R-2014-2428743

PENNSYLVANIA POWER COMPANY
DOCKET NO. R-2014-2428744

WEST PENN POWER COMPANY
DOCKET NO. R-2014-2428742

Direct Testimony
of
Michael J. Vilbert

List of Topics Addressed

Cost of Common Equity Capital

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DIRECT TESTIMONY
OF
MICHAEL J. VILBERT

I. INTRODUCTION AND SUMMARY

Q. Please state your name and address for the record.

A. My name is Michael J. Vilbert. My business address is The Brattle Group, 201 Mission Street, Suite 2800, San Francisco, CA 94105, USA.

Q. Please summarize your background and experience.

A. I am a Principal of The Brattle Group ("Brattle"), an economic, environmental and management consulting firm with offices in Cambridge, Washington, London, San Francisco, Madrid, Rome, and New York City. My work concentrates on financial and regulatory economics. I hold a B.S. from the U.S. Air Force Academy and a Ph.D. in finance from the Wharton School of Business at the University of Pennsylvania. Appendix A provides more detail on my qualifications.

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power"), and West Penn Power Company ("West Penn") (together the "Companies") to estimate the cost of capital for the Companies. Specifically, I provide return on equity ("ROE") estimates derived from a sample of comparable risk, regulated electric utility companies ("electric utilities"). I also consider the relative risk of the Companies' proposed capital structure ratios to arrive at my recommended range for allowed ROE.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Met-Ed/Penelec/Penn Power/West Penn Exhibit MJV-1 which includes the following tables:

Table No.	Description
MJV-1	Table of Contents
MJV-2	Classification of Companies by Assets
MJV-3	Market Value of the Electric Sample
MJV-4	Capital Structure Summary of the Electric Sample
MJV-5	Estimated Growth Rates of the Electric Sample
MJV-6	DCF Cost of Equity of the Electric Sample
MJV-7	Overall DCF Cost of Capital of the Electric Sample
MJV-8	DCF Cost of Equity at the Companies' Proposed Capital Structures
MJV-9	Interest Rate Forecasts
MJV-10	Risk Positioning Cost of Equity of the Electric Sample
MJV-11	Overall Risk Positioning Cost of Capital of the Electric Sample
MJV-12	Risk Positioning Cost of Equity at the Companies' Proposed Capital Structures

Q. Were these exhibits and schedules prepared by you or under your direction?

A. Yes, they were.

Q. Can you summarize the parts of your background and experience that are particularly relevant to your testimony on these matters?

A. *Brattle's* specialties include financial economics, regulatory economics, and the gas, water and electric industries. I have worked in the areas of cost of capital, investment

risk and related matters for many industries, regulated and unregulated alike, in many forums. A partial list of the regulators before which I have testified or filed cost of capital testimony include the Arizona Corporation Commission, the Pennsylvania Public Utility Commission, the Public Service Commission of West Virginia, the Public Utilities Commission of Ohio, the Tennessee Regulatory Authority, the Public Service Commission of Wisconsin, the South Dakota Utilities Commission, the California Public Utilities Commission, the Michigan Public Service Commission, and the Federal Energy Regulatory Commission ("FERC"). I have also testified in Canada before the Canadian National Energy Board, the Alberta Energy and Utilities Board, the Ontario Energy Board, the Quebec Régie de l'énergie, and the Labrador & Newfoundland Board of Commissioners of Public Utilities. Appendix A contains more information on my professional qualifications.

Q. What are the steps in your analysis?

A. To estimate the Companies' cost of capital, I analyzed a sample of electric utilities, identified as being in the same line of business as Met-Ed, Penelec, Penn Power, and West Penn, specifically the regulated electric utility business. I estimate the ROE for each sample company using both the risk positioning and the discounted cash flow ("DCF") approaches. The risk positioning approach consists of analyses based upon the Capital Asset Pricing Model ("CAPM") and the Empirical CAPM ("ECAPM"). The ROE estimates from both models are then combined with the market value capital structure information and the market costs of debt and preferred stock for each sample company to compute each firm's overall cost of capital, i.e., its after-tax weighted-average cost of capital ("ATWACC").

Q. What is the result of the cost of capital estimation process?

A. The result of this process is a sample average ATWACC for each cost of equity estimation method. I then report the cost of equity consistent with the sample's average estimated ATWACC as if the sample's average market-value capital structure had been one with a 50.0 percent equity ratio, which closely approximates the equity ratios Met-Ed, Penelec, Penn Power, and West Penn have proposed in this case. This procedure results in a ROE that is consistent with the financial risk inherent in the Companies' proposed capital structures and the market-determined information on the sample's average overall cost of capital.

Q. How does the ongoing uncertainty in the financial markets affect the cost of capital for a regulated utility?

A. The equity risk premium (or the premium of the cost of equity capital over the cost of debt) remains higher than it was before the start of the financial crisis in about mid-2008. Although economic conditions have improved substantially since the height of the crisis, some uncertainty remains in the capital markets due, in part, to the disappointing rate of economic growth, not only in the U.S., but also worldwide. Economic growth in Europe remains anemic with the ongoing fallout from the sovereign debt crisis. There is increasing uncertainty of the effects of the conflict in the Ukraine and in Iraq, and there are also concerns about the sustainability of credit growth in China. A persistently high rate of unemployment and contracting fiscal spending has led the Federal Reserve Bank ("Fed") to continue purchasing Treasury bonds and agency securities, as announced at the FOMC meeting in June 2014, the

subsequent aspects of which I will discuss later in *Section III*.[1] Although long-term government bond yields have increased over the past year, they remain at low levels by historical standards as shown in Figure 2 below.

As a result, there has been a substantial increase in yield spreads,2 both for riskier assets as well as for less risky investments such as investment grade-rated utility debt. Although the capital market indices have returned to their pre-crisis levels, the recovery remains fragile and could easily stall if any of the fears mentioned above come to pass. I discuss the effect of the credit crisis on the cost of capital and its various components, including the long-term risk-free interest rate, in more detail in *Section III* below.

This uncertainty in the financial markets also affects the results of the estimation models, because both the risk positioning model and the DCF model are based upon the assumption that economic conditions are stable. That assumption is not currently met, so estimating the cost of capital under current conditions is more complicated than it would normally be.

Q. Do you adjust your analyses to account for the remaining market uncertainty?

A. Yes. Because the uncertainty in the financial markets affects the cost of capital for all companies, including regulated utilities such as Met-Ed, Penelec, Penn Power, and West Penn, I modified the parameters of the risk positioning model to recognize the

[1] FOMC June 19, 2014 Press Release, The Board of Governors of the Federal Reserve System, Accessed at: http://www.federalreserve.gov/newsevents/press/monetary/20140618a.htm, on July 18, 2014.

[2] The yield spread in this case is the difference between the yield on a risky security and the yield on U.S. Treasury debt of comparable maturity.

effect of the increased volatility in the capital markets as well as the overall decline in long-term risk-free interest rates on the cost of capital. Specifically, I analyzed scenarios using two different estimates of the market risk premium ("MRP") and risk-free interest rate for use in the risk positioning model. These scenarios are discussed in more detail below. Further, given the current economic uncertainty and the downward bias it creates in the CAPM model results, I also place more weight than I normally would on the results of the DCF analyses in determining the range of reasonableness for the ROE, for reasons explained later in this testimony.

Q. Can you summarize your findings about the electric sample's costs of capital?

A. The sample ROE estimates range from a low of 8.7 percent to a high of 10.9 percent, but I believe that the estimates at the lower end of the range are not reliable because they do not consider the effect of the current uncertainty in the financial markets and the downward pressure on the risk-free interest rate. Conversely, the estimates at the upper end of the range reflect the adjustment for the ongoing uncertainty in the capital market and are more reliable. For an electric utility company of average business risk and with an equity ratio of approximately 50 percent the best estimate of the range for the cost of equity is from 9.3 percent to 10.9 percent.

Q. What ROE are the Companies requesting in this proceeding?

A. Mr. Staub testifies that the Companies are requesting an ROE of 10.9 percent. This is within the range 9.3 percent to 10.9 percent that I recommend for electric utilities of Metropolitan Edison Company's, Pennsylvania Electric Company's, Pennsylvania Power Company's, and West Penn Power Company's financial and business risk.

Q. How is your testimony organized?

A. *Section II* formally defines the cost of capital and touches on the principles relating to estimating the cost of capital and the effect of capital structure on the cost of equity. *Section III* discusses the impact of the fragile recovery from the credit crisis on the cost of capital. *Section IV* discusses the selection of the electric sample, and *Section V* presents the methods used to estimate the cost of capital for the sample; provides the associated numerical analyses; and explains the basis of my conclusions for the sample's overall costs of capital (ATWACC). *Section VI* concludes my testimony. The calculations supporting my analyses are provided in Exhibit MJV-1.

II. COST OF CAPITAL THEORY

A. Cost of Capital and Risk

Q. How is the "cost of capital" formally defined?

A. The cost of capital is defined as the expected rate of return in capital markets on alternative investments of equivalent risk. In other words, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected," as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

The definition of the cost of capital recognizes a tradeoff between risk and return that can be represented by the "security market risk-return line," or "Security Market

Line" for short. This line is depicted in Figure 1. The higher the risk, the higher the cost of capital required.

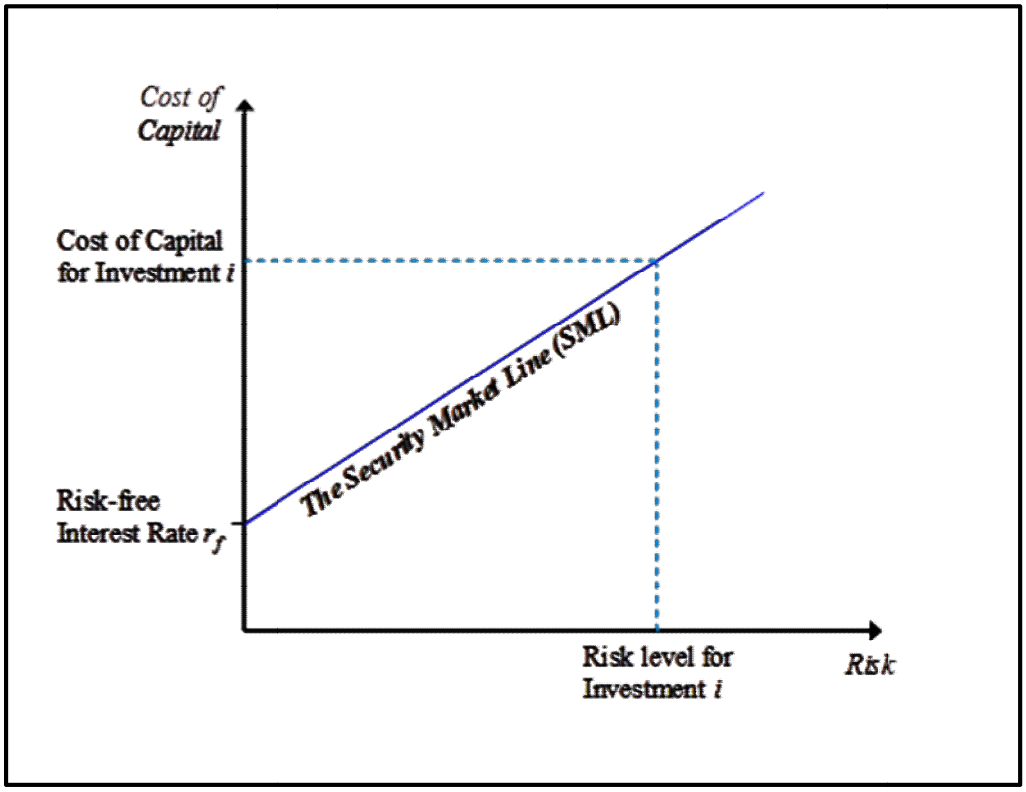


Figure 1: The Security Market Line

Q. Why is the cost of capital relevant in rate regulation?

A. It has become routine in U.S. rate regulation to accept the "cost of capital" as the right expected rate of return on utility investments.[3] That practice is viewed as consistent with the U.S. Supreme Court's opinions in *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923), and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[3] A formal link between the cost of capital as defined by financial economics and the right expected rate of return for utilities is set forth by Stewart C. Myers, *Application of Finance Theory to Public Utility Rate Cases, Bell Journal of Economics & Management Science* 3:58-97 (1972).

From an economic perspective, rate levels that give investors a fair opportunity to earn the cost of capital are the lowest levels that compensate investors for the risks they bear. Over the long run, an expected return above the cost of capital makes customers overpay for service. Regulatory commissions normally try to prevent such outcomes unless there are offsetting benefits (*e.g.*, from incentive regulation that reduces future costs). At the same time, an expected return below the cost of capital does a disservice not just to investors but, importantly, to customers as well. Such a return denies the company the ability to attract capital, to maintain its financial integrity, and to expect a return commensurate with that of other enterprises attended by corresponding risks and uncertainties.

More important for customers, however, are the broader economic consequences of providing an inadequate return to the company's investors. In the short run, deviations from the expected rate of return on the rate base from the cost of capital may seemingly create a "zero-sum game"—investors gain if customers are overcharged, and customers gain if investors are shortchanged. But in fact, in the short run, such actions may adversely affect the utility's ability to provide stable and favorable rates because some potential efficiency investments may be delayed or because the company is forced to file more frequent rate cases. Moreover, in the long run, inadequate returns are likely to cost customers—and society generally—far more than may be saved in the short run. Inadequate returns lead to inadequate investment, whether for maintenance or for new plant and equipment. Without access to investor capital, the company may be forced to forgo opportunities to maintain, upgrade, and expand its systems and facilities in ways that decrease long run costs. Indeed, the

cost to consumers of an undercapitalized industry can be far greater than any short-run gains from shortfalls in the cost of capital. This is especially true in capital-intensive industries (such as the electric utility industry), which feature systems that take a long time to decay. Such long-lived infrastructure assets cannot be repaired or replaced overnight, because of the time necessary to plan and construct the facilities. Thus, it is in the customers' interest not only to make sure the return investors expect does not exceed the cost of capital, but also to make sure that the return does not fall short of the cost of capital.

Of course, the cost of capital cannot be estimated with perfect certainty, and other aspects of the way the revenue requirement is set may mean investors expect to earn more or less than the cost of capital, even if the allowed rate of return equals the cost of capital exactly. However, a commission that sets rates so investors expect to earn the cost of capital on average treats both customers and investors fairly, and acts in the long-run interests of both groups.

B. Relationship between Capital Structure and the Cost of Equity

Q. What did you mean by the "ATWACC" mentioned earlier?

A. The ATWACC is calculated as the weighted average of the after-tax cost of debt capital and the cost of equity. Specifically, the following equation pertains:[4]

$$ATWACC = r_D \times (1 - T_C) \times \%\ D + r_E \times \%\ E \qquad (1)$$

[4] The equation is shown with only debt and common equity. If the capital structure has preferred equity, add the following term ($r_P \times \%\ P$) to the right-hand side of the equation.

where r_D = market cost of debt,
r_E = market cost of equity,
T_C = corporate income tax rate,
%*D* = percent debt in the capital structure, and
%*E* = percent equity in the capital structure

The ATWACC is commonly referred to as the WACC in financial textbooks and is used in investment decisions.[5] The return on equity consistent with the sample's overall cost of capital estimate (the ATWACC), the market cost of debt, the corporate income tax rate, and the amount of debt and common equity in the capital structure can be determined by solving equation (1) for r_E. Alternatively, if r_E is given and the capital structure is not, one can solve for %*E* instead. Having determined the ATWACC for the sample companies, I can apply that same ATWACC or an ATWACC adjusted for risk differences to the regulated entity, in this case Met-Ed, Penelec, Penn Power, and West Penn.[6]

Q. Why is the ATWACC relevant to these proceedings?

A. The ATWACC is one of several procedures in my analysis; it is important because it allows a comparison between the sample companies' costs of capital estimates and the cost of capital for Met-Ed, Penelec, Penn Power, and West Penn. Two otherwise identical companies with different capital structures will typically have different costs of equity because the risks to equity holders depend on the financial leverage (i.e., the amount of debt in the capital structure of the company). This makes it difficult to

[5] See, for example, Brealey, Myers and Allen (2011), *Principles of Corporate Finance, 10th Edition*, McGraw-Hill Irwin, New York, pp. 471-486.

[6] I refer to the ATWACC to distinguish it from the WACC used in regulatory proceedings which is the weighted-average of the after-tax cost of equity and the *pre-tax* cost of debt instead of the after-tax cost of debt.

compare cost-of-equity estimates among companies that have different capital structures. The effect of varying financial leverage on the risk-return tradeoffs of companies means that simply averaging individual cost-of-equity estimates across a sample generally does not provide meaningful information about an appropriate representative cost of capital for the industry. Thus it is generally incorrect to compute a sample average return on equity when estimating the cost of capital. However, two otherwise identical companies with different capital structures will generally have comparable ATWACC values. The "apples to apples" comparability of ATWACC across companies with different capital structures makes it a consistent measure of the representative cost of capital in an industry.

Q. How does the ATWACC approach differ from procedures where the cost of equity and the regulatory capital structure are determined separately?

A. The ATWACC approach avoids inconsistencies that could arrive from estimating the cost of equity for each of the sample firms without explicit consideration of the financial risk inherent in the market-value capital structure underlying those costs. If the sample's average cost of equity is used to estimate the cost of equity for the company in question, inconsistencies are likely to arise, because this method makes no adjustment for any differences among the capital structures of the sample firms used to estimate the cost of equity and the regulatory capital structure used to set rates. Consequently, the sample's estimated return on equity does not necessarily correspond to the financial risk faced by investors in the subject companies, in this case Met-Ed, Penelec, Penn Power, and West Penn. If the sample's estimated cost of

equity were adopted without consideration of differences in financial risk, it could lead to an unjust and inappropriate rate of return.

Q. Why is it necessary to consider the sample companies' capital structures as well as the regulatory capital structure in your analysis?

A. Briefly, the cost of equity and the capital structure are inextricably entwined in that the use of debt increases the financial risk of the company and therefore increases the cost of equity. The more debt, the higher is the cost of equity for a given level of business risk. Rate regulation has in the past often focused on the individual components of the cost of capital. In particular, it has treated as separate questions what the "right" cost of equity capital and "right" capital structure should be. The cost of capital depends primarily on the business the firm is in, while the costs of the debt and equity components depend not only on the business risk, but also on the distribution of revenues between debt and equity. The cost of capital is thus the more basic concept. Although the overall cost of capital is constant (ignoring taxes and costs of excessive debt), the distribution of the costs among debt and equity is not. Reporting the average cost of equity estimates from the sample without consideration of the differences in financial risk may result in material errors in the allowed return for Met-Ed, Penelec, Penn Power, and West Penn.

Q. What is the basis for the development of the ATWACC method?

A. Computing the ATWACC—called the weighted-average cost of capital in textbooks—is the fundamental method used by financial economists to measure the cost of capital. It is a standard topic taught in graduate level courses in corporate

finance and is based upon the work of Professors Franco Modigliani and Merton Miller. Each separately won the Nobel Prize in Economics, in part, for developing the theories underlying the method. It is critical to keep in mind that the ATWACC method is one useful tool to assist in the analysis of the cost of capital. All cost of capital witnesses estimate the cost of equity using the DCF or the risk positioning models, and all must interpret the results relative to the risk of the regulated company at issue. The purpose of the ATWACC method is to allow an "apples to apples" comparison of the results of the sample companies by adjusting for differences in financial risk due to differences in capital structure. The ATWACC is sometimes mischaracterized in regulatory proceedings and incorrectly criticized, possibly because the critics do not like the method's results, but it is the standard methodology in finance. It is consistent with the use of rate base measured on the basis of book value, and does not require a regulator to "rubber stamp" the current market value of the regulated company's stock as is sometimes asserted.

III. IMPACT OF THE RECENT ECONOMIC UNCERTAINTY

Q. What is the topic of this section of your testimony?

A. This section addresses the effect of the current economic situation on the cost of capital and the adjustments to my standard procedures required to estimate the cost of capital more accurately.

Q. Do you believe that capital markets are "back to normal"?

A. No. Although the volatility in the financial markets has lessened and economic conditions have improved markedly, I do not believe that capital markets (and the broader economy) are back to normal as compared to their pre-crisis status.

Q. What are the major remaining uncertainties?

A. Although unemployment has been declining, it remains high by historic standards and in fact it would be much higher except that the labor force participation rate[7] has declined from 66.1 percent in January 2004 to 63.4 percent recently.[8] This low level of labor force participation has not been observed since 1978, and may reflect the fact that many people who would otherwise be counted as unemployed have become discouraged and given up looking for work.

Additionally, while the Fed has begun scaling back (i.e., "tapering") its asset purchasing program, it is doing so gradually. Specifically, the Fed reduced purchases to $75 billion per month in January of 2014,[9] and announced a further reduction to $35 billion starting in July 2014.[10] This still represents a high level of continuing purchases of financial assets, and although the rate of accumulation is slowing, the Fed is still actively increasing its already massive inventory. Not only must the Fed

[7] Labor force participation is the percentage of the working age population with a job or seeking one.

[8] See Bureau of Labor Statistics, Labor Force Statistics from Current Population Survey, data extracted July 18, 2014.

[9] Federal Reserve Bank of New York, "Statement Regarding Purchases of Treasury Securities and Agency Mortgage-Backed Securities," December 18, 2013.

[10] Federal Reserve Bank of New York, "Statement Regarding Purchases of Treasury Securities and Agency Mortgage-Backed Securities," June 18, 2014.

reduce its ongoing purchases, but it must also reduce this inventory of Treasury bonds and agency mortgage backed securities, which it accumulated in an effort to stimulate capital markets and keep interest rates low. The Fed's inventory of bonds increased from less than $869 billion in August 2007 to over $4 trillion at the end of 2013.[11] Unwinding this position will be a gradual process, and substantial effects of the taper on capital markets and interest rates will not (and have not) materialize overnight.

Furthermore, budget deficits at all levels of government are at high and unsustainable levels, and the potential exists for higher inflation as a result of deficit spending by the U.S. government and further liquidity injected into the capital markets by the Fed.

Q. What is the purpose of the Fed's asset purchases?

A. The Fed purchases bonds and other financial assets to stimulate the economy, reassure the capital markets, and keep interest rates low. The primary purpose of the asset purchase program was to drive down long-term interest rates, and in this regard it has been successful. The effectiveness of this policy is evidenced by the fact that U.S. Treasury Bond yields remain low by historical standards. Long-term and short-term interest rates were driven to historic lows[12] before beginning to increase with the start of tapering. The goal of the programs was to spur economic activity by making it cheaper to borrow funds for new investment or to purchase durable assets such as houses and automobiles.

[11] *Bloomberg News*, "Fed Assets Reach Record $4 Trillion on Unprecedented Bond Buying," by Jeff Kearns, December 19, 2013.

[12] See for example, the "long term stock, bond, interest rate and consumption data" provided at Professor Robert Shiller's website: http://www.econ.yale.edu/~shiller/data.htm

Q. What effects did the Fed's purchases have on equity and other markets?

A. During the crisis and its aftermath, the Fed's purchases supported the stock market by depressing the expected returns to bond investors. In times of economic uncertainty (such as the financial crisis), investors seek to reduce their exposure to market risk. This precipitates a so-called "flight to safety," wherein demand for low-risk government bonds rises at the expense of demand for stocks. If yields on bonds are extraordinarily low, however, any investor seeking a higher expected return must choose alternative investments such as stocks, real estate, or gold or collectibles. Of course, all of these investments are riskier than government bonds, and investors still demand a risk premium (perhaps an especially high one in times of economic uncertainty) for investing in them. But short of accepting meager returns, investors simply have few alternatives to returning to the stock market. Thus, the Fed's bond purchases somewhat mitigate the effect of the "flight to safety" on equities and other investments. Utility stocks in particular benefit from this phenomenon because of their dividends. Emerging market countries benefited too, as investors sought higher returns. Sales of houses also improved because of record low mortgage rates, and automobile sales have been at high levels as well.

Q. What has been the effect of the start of tapering?

A. Interest rates have increased since the possibility of tapering was first discussed in June 2013. (See Figure 2 below.) However, the pace of that increase slowed toward the end of last year, and rates have decreased only slightly so far in 2014. This may indicate that bond markets have adjusted somewhat to the Fed's reduced rate of purchases. Although they have recovered somewhat from their lows in 2012 and

early 2013, long-term U.S. treasury yields remain well below their pre-crisis and long-term average levels.

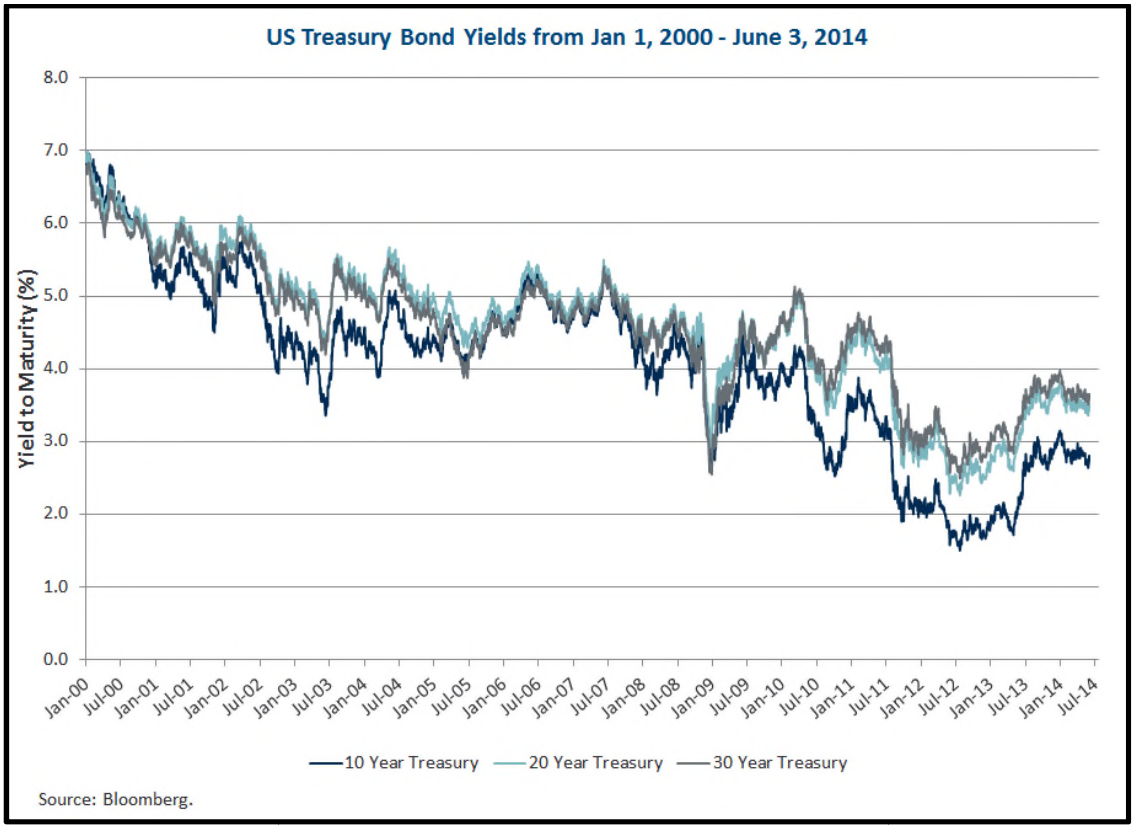


Figure 2

Investor uncertainty is illustrated by the flow of funds into and out of mutual funds. (See Figure 5, later in my testimony.) Transfers out of bond mutual funds spiked when the Fed first discussed tapering, and stayed high through the end of 2013. This was likely driven by the possibility of rising interest rates, which would lead to falling bond prices. However, the half of 2014 saw positive and increasing net flows into bond funds, reflecting a shift in expectations about interest rates: market participants are less convinced that rates will rise in the near term. Flows into equity mutual funds, meanwhile, have been somewhat erratic, with recent outflows suggesting that investors may not have fully regained their appetite for risky stock investments.

Q. Has the yield spread between government and utility bonds changed since the start of the credit crisis?

A. Yes. Although the yield on utility bonds had declined somewhat from the height of the crisis (and has decreased since the start of the taper), it has been higher during most of the past two years than it was prior to the credit crisis. As shown in Figure 3 below, since the last major peak in November 2008 the spread between the yield on BBB-rated 20-year utility bonds and the yield on 20-year government bonds has ranged from a low of 138 basis points to a high of 418 basis points, compared to a historical average of approximately 150 basis points.[13]

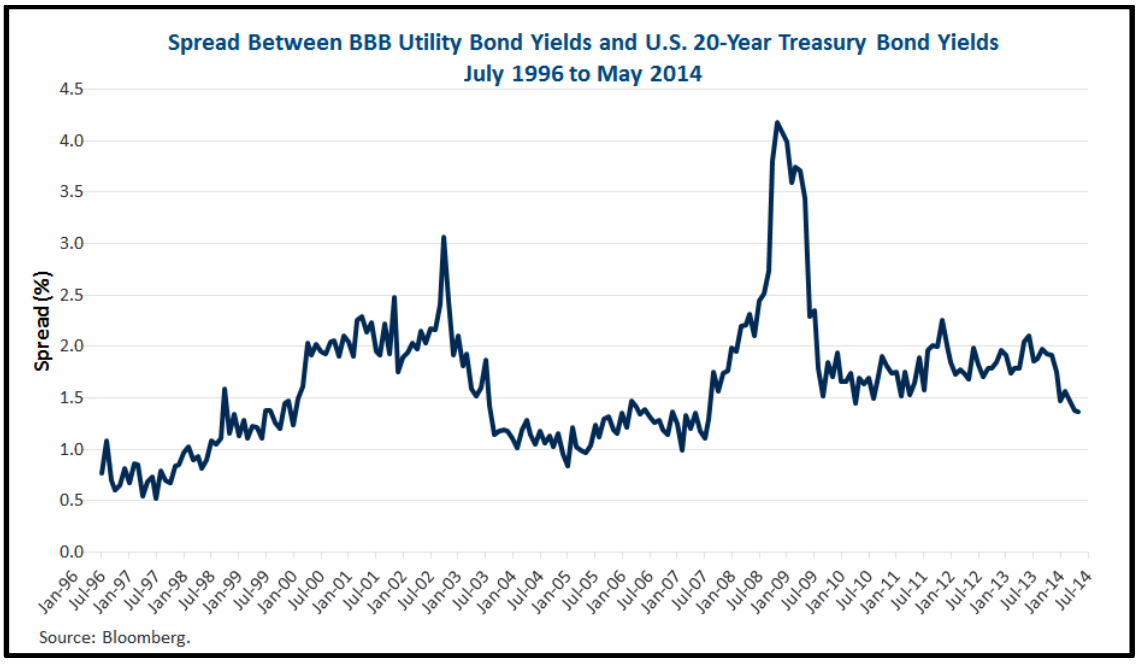


Figure 3

[13] For the 10-year period ending October 31, 2008, the average spread was 161 basis points and for the 10-year period ending October 31, 2007, the average spread was 148 basis points.

Table 1 below presents the yield spreads for 20-year utility bonds over several historical periods. Yield spreads have begun to increase again in the most recent period compared to the long-term pre-crisis average measured from 1991-2007.

Spreads between US Utility Bond (20 year maturity) and US Treasury Bond (20 year maturity) - %			
Periods	A-Rated Utility and Treasury	BBB-Rated Utility and Treasury	Notes
Period 1 - Average April 1991 - 2007	0.93	1.23	[1]
Period 2 - Average Aug-2008 - May-2014	1.58	2.07	[2]
Period 3 - Average May-2014	1.04	1.57	[3]
Period 4 - Average 15-Day (May 13, 2014 to Jun 03, 2014)	1.18	1.44	[4]
Spread Increase between Period 2 and Period 1	0.65	0.84	[5] = [2] - [1].
Spread Increase between Period 3 and Period 1	0.11	0.34	[6] = [3] - [1].
Spread Increase between Period 4 and Period 1	**0.25**	**0.21**	[7] = [4] - [1].
Sources and Notes:			
Spreads for the periods are calculated from Bloomberg's yield data.			
Average monthly yields for the indices were retrieved from Bloomberg as of June 3, 2014.			

Table 1

Q. What is the implication of higher than normal yield spreads?

A. A higher than normal yield spread is one indication of the higher risk premium prevailing in the capital markets. Investors consider a risk-return tradeoff (like the one displayed in Figure 1 above) and select investments based upon the desired level of risk. Higher yield spreads reflect the fact that the return on corporate debt (i.e., the cost of debt) is higher relative to government bond yields than is normally the case, even for regulated utilities. Because debt is less risky than equity, this means that the cost of equity must also be higher relative to government bond yields than is usually observed. If this fact is not recognized, then the traditional cost of capital estimation models will underestimate the cost of capital prevailing in the capital markets.

Q. Are the higher than normal yield spreads an indication of investors' "flight to safety"?

A. Yes. When investors become concerned about the economy, they frequently seek to reduce their exposure to investment risk. U.S. government debt is generally considered the least risky available investment—in effect it is regarded as the closest thing to a risk-free asset. Thus U.S. government debt is in high demand during times of economic uncertainty. This implies in turn that the yields on U.S. government bonds are likely to be relatively lower during periods of economic turmoil. Moreover, the U.S. Fed's continued bond purchase programs have further increased the demand for medium- and long-term U.S. government bonds, thus depressing the yields on those bonds.

Q. What evidence can you provide that U.S. medium- and long-term government bond yields are currently depressed?

A. Over the past few years, the annual yields on long-term U.S. government bonds have dropped dramatically and remain depressed. For instance, the historical average of annual yields on long-term government bonds was 5.16 percent from 1926 to 2012, but long-term government bond yields were 2.48 percent in 2011 and 2.41 percent in 2012.[14] However, the easing of the pace of Fed bond purchases and some recent outflows from bond funds have translated to a modest rise in bond yields. As a result, the current yield is up slightly from the recent lows, at 3.10 percent (based on the 15-

[14] 2013 Ibbotson Associates, Stocks Bonds Bills (SBBI) and Inflation monthly paper reports.

day average of long-term government bond yields as of June 3, 2014).[15] But this is still substantially below the long-term historical average.

Forecasted medium-term yields also suggest that current yields are depressed. *Blue Chip Economic Indicators* dated March 10, 2014 reports the consensus economic projections for the yield on 10-year U.S. Treasury notes to be 4.1 percent in 2016 and 4.5 percent in 2017. These consensus forecasts suggest that 10-year Treasury note yields will trend upward to 4.6 percent on average for 2016-2020 and 4.8 percent on average for 2021-2025.[16] These forecasts are substantially higher than the recent 2.5 percent average yield on 10-year U.S. government notes,[17] and highlight the fact that current long-term and medium-term U.S. government bond yields are low both relative to historical levels, as well as compared to consensus forecasts of future rates. The currently depressed level of long-term government bond yields must be considered when evaluating the results of the risk-positioning model, because the downward bias in the long-term risk-free interest rate will inappropriately lower the sample companies' ROE estimates that would result from mechanically calculating the CAPM.

Q. Do regulated companies benefit from the flight to safety?

A. Yes, to some degree. Regulated companies are of lower relative risk than the average company in the market, and so investors may prefer to invest in them rather than in

[15] See Table No. MJV-9.

[16] See *Blue Chip Economic Indicators*, dated March 10, 2014, page 15.

[17] As of June 3, 2014, See Table No. MJV-9.

riskier companies during bad times. However, the required return for *all* types of risky investments, including regulated utilities, increases during a time of flight to safety, since corporate and (especially) "risk free" government bonds are in turn much less risky than even the equity of regulated companies. This was borne out amidst the recent turmoil: prices of regulated companies fell along with the broader market, although not as much in percentage terms as the market, but that is to be expected because regulated companies are of lower risk. The risk-positioning models predict that companies with lower betas, i.e., companies with lower relative risk, will move with the market, but with lower volatility. The prices of regulated companies recovered faster than the market, in part because of the flight to safety, but have now been surpassed by the general market, again as expected by the predictions of the risk-positioning models.

Q. Why is it important to consider the stock market's volatility?

A. Academic research finds that investors expect a higher risk premium during more volatile periods. The higher the risk premium, the higher is the required return on equity. For example, French, Schwert, and Stambaugh (1987) find a positive relationship between the expected market risk premium ("MRP") and volatility:

> We find evidence that the expected market risk premium (the expected return on a stock portfolio minus the Treasury bill yield) is positively related to the predictable volatility of stock returns. There is also evidence that unexpected stock returns are negatively related to the unexpected change in the volatility of stock returns. This negative

relation provides indirect evidence of a positive relation between expected risk premiums and volatility.[18]

One implication of this finding is that the MRP tends to increase when market volatility is up, even when investors' level of risk aversion remains unchanged. Recently, market expectations for the volatility of the S&P 500 index have been lower than their long-term average of approximately 20 percent.[19] However, as can be seen in Figure 4, the variability in monthly stock market volatility has itself been quite high over the past 6 months, with occasional spikes indicating periods of increased uncertainty about likely market outcomes.

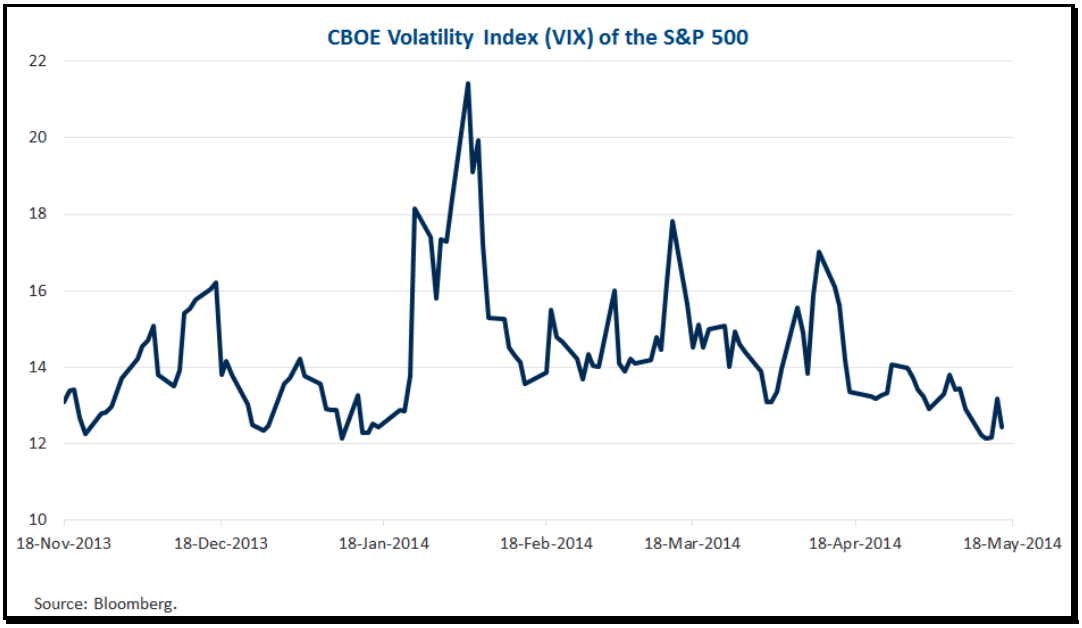


Figure 4

[18] K. French, W. Schwert and R. Stambaugh (1987), "Expected Stock Returns and Volatility," *Journal of Financial Economics*, Vol. 19, p. 3.

[19] As measured by the CBOE Volatility Index (VIX) which measures market expectations for (annualized) 30-day volatility of the S&P 500 stock index based on implied volatility of options on the S&P 500. The average closing index value for the VIX from January 2004 to May 2014 was 20.0. See http://www.cboe.com/micro/vix/historical.aspx.

Q. What do you mean by the term "risk aversion"?

A. Risk aversion is the recognition that investors dislike risk, which means that for any given level of risk, investors must expect to earn a higher return to be induced to invest. An increase in risk aversion means that investors require an even greater return for a given level of risk.

Q. Do you have any evidence that the return premium demanded by investors for taking risk is higher than it was prior to the crisis?

A. Yes. In response to the crisis, investors began allocating much larger shares of their portfolios to lower risk investments. In fact, many investors have left their money in cash or low-yielding Treasuries rather than investing in stocks. For example, Figure 5 below compares monthly net new mutual fund flows into U.S. domestic equities versus total net flows into bonds. Figure 5 shows that net cash flow into domestic equities was predominantly negative from mid-2010 through the end of 2012, reaching almost $30 billion in outflows in July 2011. On the other hand, net flows into bonds were consistently positive throughout the crisis and its aftermath, with monthly inflows reaching nearly $35 billion at several points in 2012 and early 2013.

As discussed above, the latter trend reversed sharply in the second half of 2013—likely in response to the Fed's announcement in June 2013 regarding the tapering of its quantitative easing program.[20] This announcement led to a dramatic global bond sell-off, headlined by $60 billion in outflows from U.S. bond mutual funds as of June

[20] "Fed message gets through to markets, sort of", Alister Bull, July 16, 2013, *Reuters*.

2013.[21] Through the latter half of 2013, bond yields climbed as demand for bonds dipped,[22] reflecting expectations that interest rates would finally rise after remaining so low for so long. At the start of 2014, many traders held short positions in U.S. Treasury bonds—effectively betting that government bond prices would fall as the interest rates rose in response to a growing economy. However, these expectations failed to materialize. Instead, the first five months of 2014 saw a rally in bond buying (see Figure 5). By the end of May, Treasury yields were trading near their lowest levels since before the Fed's June 2013 tapering announcement.[23] This bond rally has surprised many market observers, since U.S. economic indicators have shown modest improvement and most forecasters continue to expect higher interest rates in the medium term.[24] Nevertheless, investors who bet against bonds at the end of 2013 moved back into safe debt investments when predicted interest rate rises failed to materialize.

Additionally, U.S. Treasury bonds are especially appealing in 2014 when compared to European sovereign debt, for which yields are being driven down by slow economic growth and resulting monetary stimulus from the European Central Bank ("ECB"). In June of 2014, the ECB made history by establishing a negative bank deposit rate—effectively charging banks money for depositing their money in the

[21] *Ibid.*

[22] Bond yields rise when prices fall, since face value and coupon payments are fixed.

[23] "Treasurys Rally, Sending 10-yr Yield to 2014 Low", Cynthia Lin, May 28, 2014, *The Wall Street Journal.*

[24] See, for example, *Consensus Forecasts*® June, 2014 survey, which predicts 10-Year Treasury Bond yields will increase from 2.6% as of the survey to 4.1% by the end of 2015.

central bank rather than lending it to consumers and businesses.[25] This accommodative stance by the ECB reflects a low interest rate outlook for European markets, perhaps driving bond investors to seek potential upside in the U.S. debt market.

The U.S. stock market has generally performed well in 2013 and 2014, but net flows for U.S. equity mutual funds have not exhibited a consistent trend. Although the uniform outflows observed in the early part of this decade are no longer manifest, there is not a clear indication in the data that investors are ready to move their money back into equities. Indeed, the short term trend of increasing outflows observed in April and May of 2014 (see Figure 6)—together with the increased demand for bonds—suggests that a clear preference for lower-risk assets currently prevails in financial markets.

In general, these trends are consistent with my observation that the average investor's risk aversion remains elevated. Additionally, the particular circumstances leading to the current low bond yields may be short-term phenomena, suggesting that current yields may underestimate the long-term risk-free interest rate. As discussed in greater detail below, a higher-than-normal equity risk premium and an underestimated risk-free rate may lead to a downward bias in cost of capital estimates based on the CAPM and ECAPM.

[25] "ECB Unveils Rate Cuts, Lending Package", June 5, 2014, *The Wall Street Journal.*

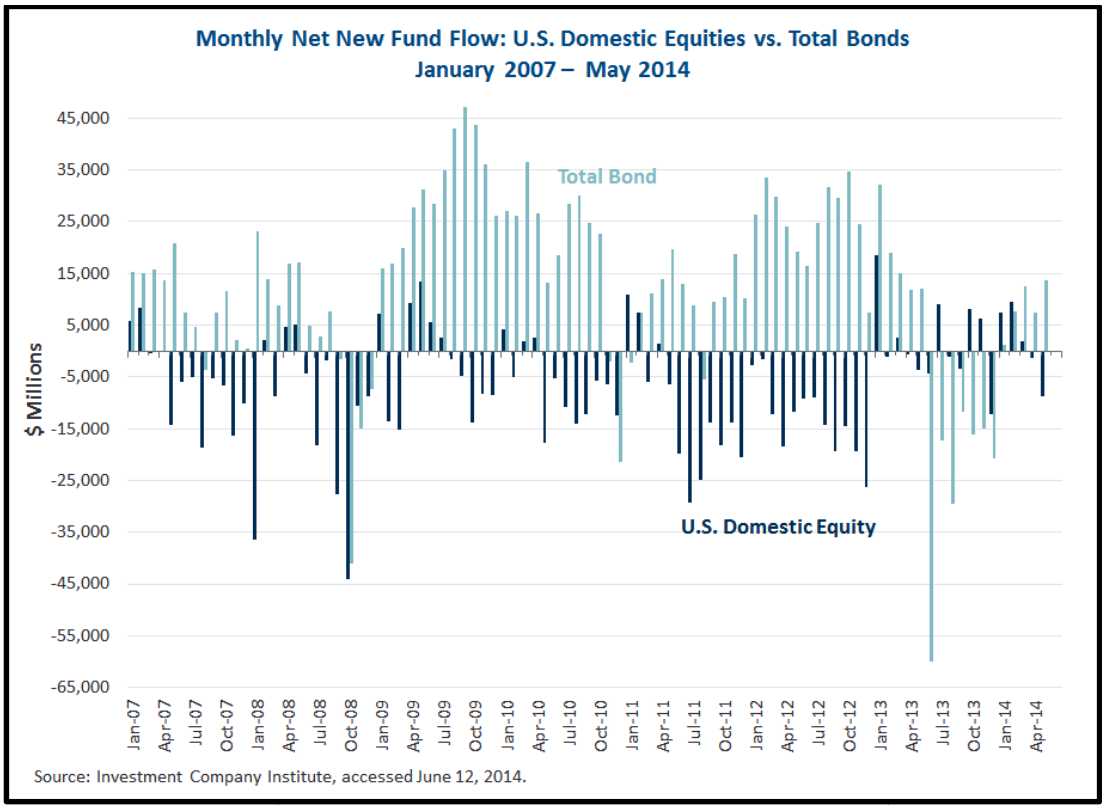


Figure 5

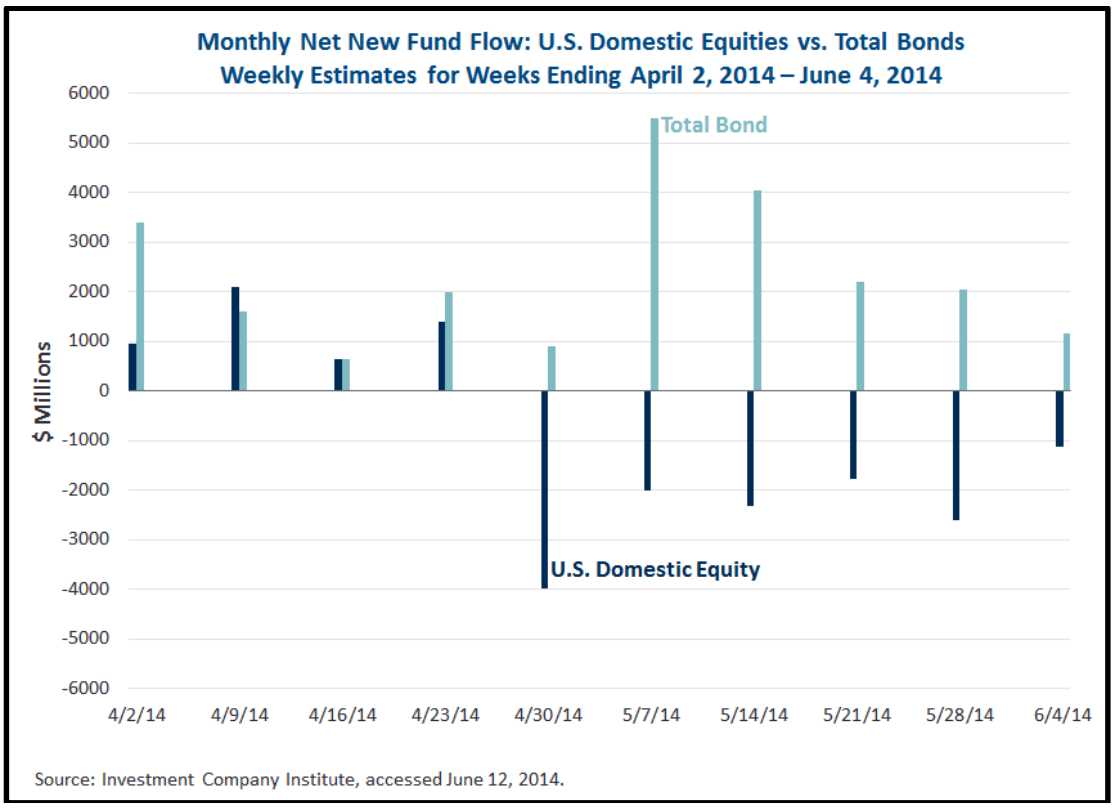


Figure 6

Q. Do you believe that the increase in the market risk premium is a short-term or a long-term phenomenon?

A. I believe that it is a long-term phenomenon. Even when market conditions return to normal, investors' risk aversion is likely to remain higher until their confidence fully returns, which is likely to be well into the recovery period. It could easily be years before investors regain the level of confidence that prevailed prior to the crisis. For a sizable group of investors, the stock market collapse of 2008-2009 has had a much more fundamental impact than wiping out a large part of their savings. In fact, it changed their perception of risk and their appetites for taking on risk again. For many investors, it changed their lifestyle. Some cannot retire as soon as expected, and others have had to sell their homes in a down market, or have lost their homes. This negative shock to investors' confidence and risk preferences is likely to have a sustained impact on their portfolio allocation choices and may persist for some time. If investors have fundamentally changed their attitude towards risk as the evidence suggests, then the required reward for investing in the stock market, i.e., the MRP, must have gone up and is likely to stay at a higher-than-normal level for the foreseeable future. An increase in the MRP results in an increase in the cost of capital for all risky investments including regulated utilities.

Q. Given that much of the economic crisis was rooted in the housing market, has the housing market in the U.S. fully recovered?

A. No. Figure 7 demonstrates that while nation-wide housing prices have begun to recover, they remain lower than they were pre-crisis.

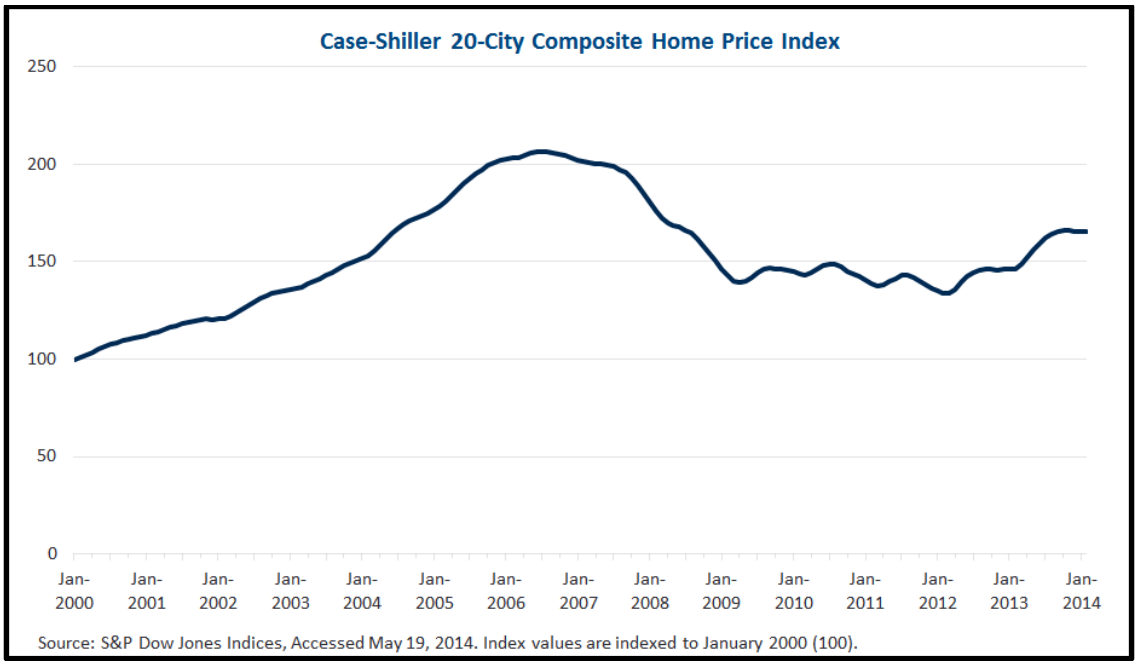


Figure 7

The decline in housing prices, which started in 2006, was a leading indicator of the decline in the financial markets because so much of the economy is dependent on the housing sector. Not only do individuals have a substantial amount of their wealth tied up in their homes, but financial institutions also have significant exposure to mortgage-backed securities. Accordingly, falling prices for homes affect much of the rest of the economy. As of the first quarter of 2013, more than 25 percent of the population had home equity value that was negative,[26] and as shown in figure 6, national home prices have not improved substantially since that time. Throughout most of the country, home prices remain far below pre-crisis levels, despite the recent improvements. As a result, borrowing and household consumption remain constrained.

[26] "Millions Remain Trapped by 'Effective' Negative Equity in Q1, Even if They're Not Underwater," Zillow Real Estate Research, Accessed August 8, 2013.

Q. What do other macroeconomic indicators suggest about the status of the recovery?

A. Unemployment is also an important issue for the health of the overall economy since it affects consumer spending and consumer confidence. Figure 8 below displays the national unemployment rate from 1990 to today. It is clear that unemployment has declined materially from its peak (around 10 percent) during the crisis and is following a sustained downward trend. However, the national unemployment rate remained at approximately 6.3 percent in May 2014,[27] which is higher than it has been since the early 1990s. Even though the unemployment rate is declining, the number of jobs created in the private sector has still been below expectations. Labor force participation remains at its lowest level since the 1970s, suggesting that many discouraged workers without jobs may not even be counted in the current unemployment rate. Overall, the U.S. labor market appears stronger than during the crisis, but does not suggest consumer and investor confidence are truly "back to normal."

[27] http://research.stlouisfed.org/fred2/graph/?id=UNRATE



Figure 8

Q. What are your thoughts on the possible effect of the budget deficit on the economy?

A. In dollar terms, the federal budget deficit was $680 billion in fiscal year 2013, down substantially from more than $1 trillion in fiscal year 2012. This improvement may result partially from the budget sequestration that went into effect in early 2013. However, the 2013 fiscal year deficit was still approximately 50 percent higher than that of 2008 and well above the average level in the years leading up to the crisis. The U.S. Congressional Budget Office estimates that the budget deficit will represent approximately 3 percent of the Gross Domestic Product ("GDP") in 2014 and will

remain high relative to economic output over the foreseeable future (see Figure 9 below).[28]

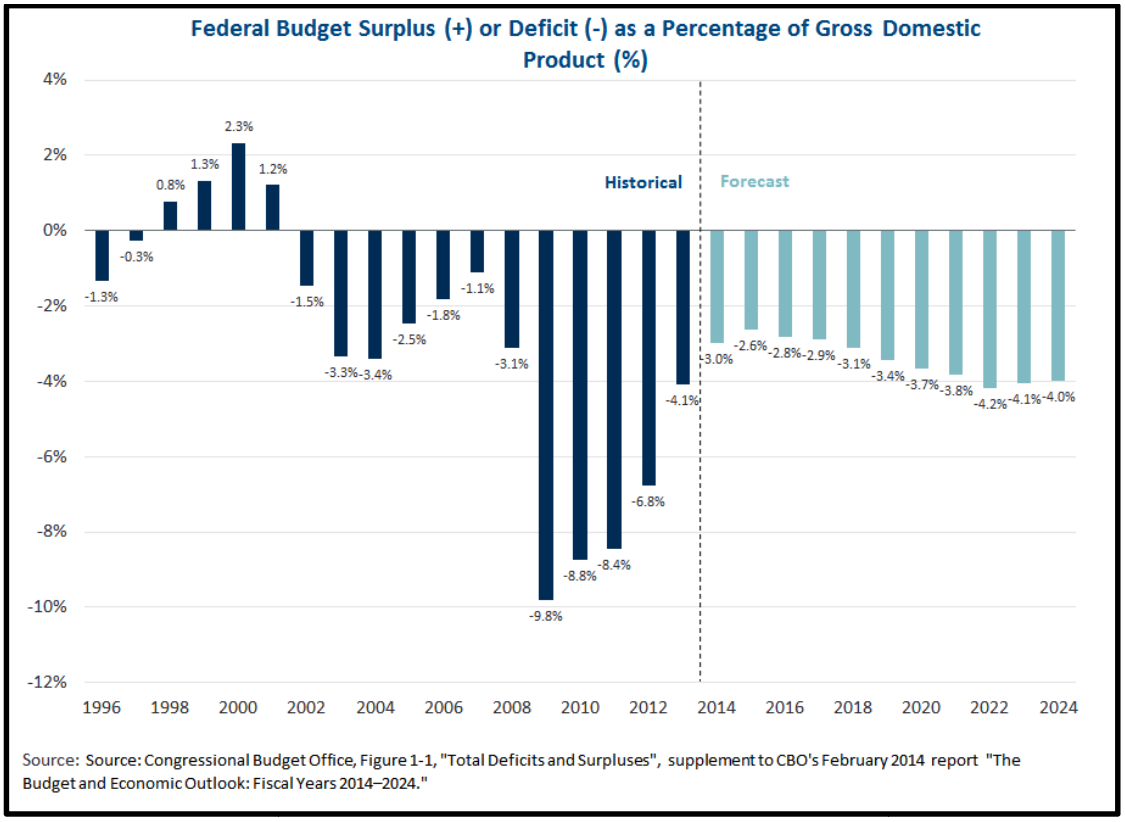


Figure 9

Maintaining such a high deficit is unsustainable, especially if buyers of U.S. debt lose confidence in the U.S. economy and demand higher interest rates in return. This suggests that going forward, the U.S. will have to be more fiscally conservative, and limit the stimulus funds it provides to the economy. Although inflation is not currently an issue, it is also quite likely that the magnitude of the federal budget deficit will affect U.S. inflation going forward. The Fed now holds approximately

[28] Congressional Budget Office: http://www.cbo.gov/.

$1,656 billion in mortgage-backed securities.[29] It is unclear how the unwinding of these positions will affect financial markets, which creates additional uncertainty.

Q. Can you summarize how the economic developments discussed above have affected the return on equity and debt that investors require?

A. Companies such as Met-Ed, Penelec, Penn Power, and West Penn rely on investors in capital markets to support efficient business operations. These investors have been dramatically affected by the credit crisis, and while there have been material improvements in capital markets and the macro-economy since the height of the financial crisis, there is evidence that investors' confidence remains low and their risk aversion remains elevated relative to pre-crisis periods.

Many lost their jobs, their homes or their savings in the crisis; many cannot retire as early as hoped or planned. Even though the economy is improving, the speed and duration of that recovery remains highly uncertain. Likewise, the effects of the federal budget deficit and the Fed's unwinding of its involvement in providing credit may have substantial but uncertain effects on the economy and financial markets. Finally, due to increased risk-aversion on the part of investors, as well as continued bond-purchase programs initiated by the Fed, long-term U.S. government bond yields (along with forecasts of future interest rates) have been pushed down to extremely low levels by historical standards. As a result, yield spreads on utility debt, including top-rated instruments, have remained elevated. The evidence presented above demonstrates that the equity risk premium is higher today than it was prior to the

[29] Federal Reserve Statistical Release as of May 22, 2014. (http://www.federalreserve.gov/releases/h41/).

crisis for all risky investments. This is true even for investments of lower-than-average risk, such as the equity of regulated utilities.

Q. How do you adjust your cost of capital estimation methods to correct for current economic conditions?

A. I make no adjustment to the DCF method, for two reasons. First, the DCF method is based on forward-looking inputs and so is less likely to be biased by estimated parameters from time periods that do not reflect current market sentiment. Second, it is difficult to make an appropriate adjustment.

For the risk positioning method, I recognize the unusually large yield spreads on utility debt by adding a "yield spread adjustment" to the current long-term risk-free rate. This has the effect of increasing the intercept of the Security Market Line displayed in Figure 1 above. I also present results from the risk positioning model by increasing the MRP over the 6.5 percent that I normally use. This has the effect of increasing the slope of the Security Market Line displayed in Figure 1. I present sensitivity tests of the effect of an increase in the MRP to 7.5 percent and yield spread adjustments to the risk-free rate of 25 basis points ("bps"). Table 4 below lists the parameters of these two scenarios.

Q. How do you estimate the increase in MRP needed to adjust for the increased cost of capital stemming from the current market turmoil?

A. Estimating the MRP is always imprecise and controversial. Measuring the change in MRP due to the current economic situation is likely to be no different, but it is still necessary to estimate the MRP as carefully as possible given the change in economic

conditions. Fortunately, there is a way to provide a quantitative benchmark for the required increase in MRP based upon a paper by Edwin J. Elton, et al., which documents that the yield spread on corporate bonds is normally a combination of a default premium, a tax premium, and a systematic risk premium.[30] As displayed in Table 1 above, the yield spreads for A-rated and BBB-rated utility debt have increased substantially compared to the average for the period 1991-2007.

Q. How do you use the information concerning the increase in yield spreads to estimate the increase in the MRP?

A. Table 1 above shows that yield spread for A-rated has increased by about 25 bps for 20-year maturities. This means that investors require a higher return on investment grade utility debt relative to the return on U.S. Government debt than before the credit crisis. Some of the increase in yield spread for A-rated debt may be due to an increase in default risk, but this is more likely to be a factor for BBB-rated utility bond yields.[31] The increase in the default risk premium for A-rated debt is undoubtedly very small because A-rated utility debt has not been at the center of the wave of defaults based upon collateralized mortgage debt. This means that the vast majority—if not all—of the increase in A-rated yield spreads is due to a combination of the increased systematic risk premium and the downward pressure on the yields of government debt caused by the flight to safety. In other words, either the market risk premium has increased or the risk-free rate is underestimated, or both. Therefore, I

[30] "Explaining the Rate Spread on Corporate Bonds," Edwin J. Elton, Martin J. Gruber, Deepak Agarwal, and Christopher Mann, *The Journal of Finance*, February 2001, pp. 247-277.

[31] Although there is no increase in tax premium due to coupon payments, there may be some increase due to a small tax effect resulting from the probability of increased capital gains taxes when the debt matures.

consider possible allocations of the 25 bps increase in A-rated utility spreads between an increase in the MRP (which drives the increase in systematic risk premium on A-rated debt), or downward pressure on the risk-free rate.

Q. How do you allocate the increase in the yield spread to the increase in systematic risk or to the under estimation of the risk-free rate due to downward pressure on government bond yields?

A. There is no precise way to allocate the increase in yield spread between the increase in systematic risk and the underestimation of the risk-free rate arising from downward pressure on government bond yields. However, assuming a beta of 0.25 for A-rated debt[32] means that an increase in the MRP of one percentage point translates into a ¼ percentage point increase in the risk premium on A-rated debt (i.e. 0.25 (beta) times 1 percentage point (increase in MRP) = ¼ percentage point increase in yield spread). The relationship among the increased yield spread for A-rated utilities ($\Delta\, spread$), the underestimation of the risk-free rate (Δr_f), and the required adjustment to the market risk premium ($\Delta\, MRP$) can be represented as follows.

$$\Delta\, spread - \Delta r_f = 0.25 \cdot\ \Delta\, MRP$$

A 25 bps increase in the yield spread is therefore consistent with a 1 percentage point increase in the MRP if there is no underestimation of the risk-free rate (i.e., 25 bps – 0 bps = 25 bps/.25 = 1.0). Alternatively, the 25 bps increase in the yield spread could

[32] Elton, *et al*. estimates the average beta on BBB-rated corporate debt as 0.26 over the period of their study, and A-rated debt will have a slightly lower beta than BBB-rated debt.

be consistent with a ¼ percentage point underestimation of the risk-free rate, with no adjustment to the MRP required (i.e., 25 bps less 25 bps = 0 bps/.25 = 0.0).

The greater the increase in yield spread assumed to be attributed to an increase in systematic risk, the larger must be the corresponding increase in the MRP and the smaller the assumed effect of downward pressure on the risk-free rate. As illustrated above, if all of the non-default increase in the yield spread were due to the increase in systematic risk, then the MRP would have to increase by 1.0 percentage point to explain the 25 bps change. Alternatively, a 25 bps increase in the yield spread is also consistent with a 25 bps underestimation of the risk-free rate, assuming that none of the change in yield spread is driven by an increase in systematic risk. These are the two scenarios I implement in my analyses.[33] The former (labeled "Scenario 2") attributes the increased yield spread entirely to an increase in systematic risk and an attendant increase in the premium required by investors for taking market risk (i.e., the MRP). Meanwhile, the latter ("Scenario 1") attributes the entire yield spread increase to the temporarily depressed government bond yields caused by the actions of the Fed and the "flight to safety" in the wake of the financial crisis.

Q. Would the estimate of the effect of an increase in the MRP be different if the estimate of the beta of an A-rated bond were different?

A. Yes. If the beta of an A-rated bond were higher, then the increase in the systematic risk premium in the yield spread for each one percentage point increase in the MRP

[33] See Exhibit MJV-1. Results for the two scenarios are presented in Panels A ("Scenario 1") and B ("Scenario 2") of Table No. MJV-10 and Table No. MJV-11. The results for both scenarios are summarized in Table No. MJV-12.

would be smaller and vice versa. However, I believe that a beta estimate of 0.25 for A-rated utility debt is reasonable, because the debt of any company is less risky than its equity. A beta estimate of 0.25 for A-rated utility debt is likely quite conservative, especially when compared to an average estimated beta of 0.78 (*Value Line* betas) for the equity of the full electric sample, given that equity is much riskier than debt. (See Table 3 later in my testimony for the estimated betas of the electric sample). Moreover, the average estimated beta for BBB-rated debt was 0.26 at the time of the Elton, et al. study, which should be higher than the estimated beta for A-rated debt, given that lower rated debt is naturally more sensitive to market risk. Even if the average beta for BBB-rated debt is higher today than at the time of the Elton, et al. study, it is likely that an estimate of 0.25 for A-rated debt is on the high end of a reasonable range. Such an estimate is also conservative in the sense that a relatively higher estimate of beta allows the increased yield spread to be explained by a relatively smaller increase in the systematic risk premium.

Q. Would you provide a graph of how the scenarios you consider affect the Security Market Line?

A. Yes, see Figure 10 below. Scenario 1 attributes the entire increase in the yield spread on A-rated utility debt to underestimation of the risk free rate by shifting the Security Market line up in parallel fashion by 25 bps ($R_1^F - R_0^F$). Scenario 2 attributes the entire increase in the yield spread to an increase in the market risk premium by increasing the slope of the line by 1.0 percentage point ($\Delta\, MRP$).

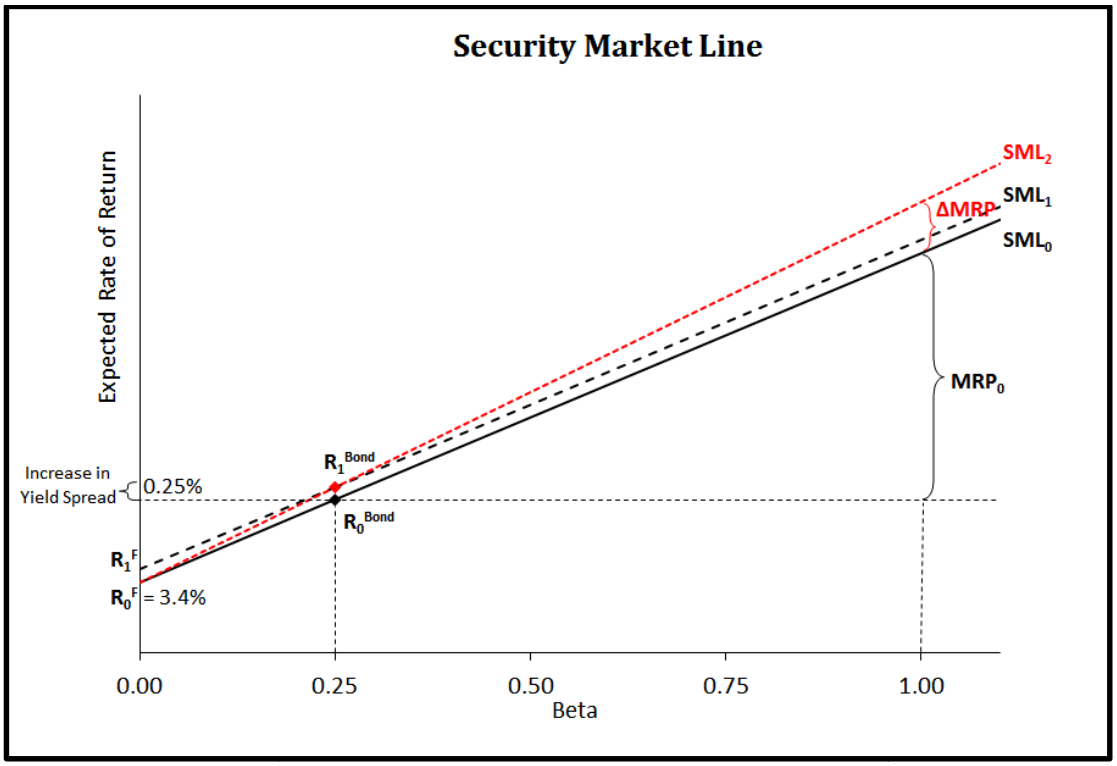


Figure 10

Q. Can you summarize your thoughts with regard to the MRP and the financial crisis?

A. Yes. There remain serious concerns of a very slow growth recovery. Banks continue to fail or are stressed in countries around the world, in an increasingly global economy. It defies logic to believe that the MRP has not increased from its level in more normal times, whether there is any particular agreed model for how to calculate the increase or not.

In light of these circumstances and the calculations described above, I submit that a 100 bps increase in the MRP presents a reasonable adjustment that might be made. As discussed in the Empirical CAPM estimation below, I have two scenarios with alternative adjustments to the risk-free rate and the MRP. These scenarios recognize

the simple reality that while the financial uncertainty and interventions by the Fed and the U.S. government have made it more difficult to measure the cost of equity accurately, the required return on equity has not decreased as much as mechanical implementation of the models might suggest.

IV. SAMPLE SELECTION

A. The Electric Sample

Q. What factors do you consider in selecting a proxy group?

A. The cost of capital for any part of a company depends on the risk of the lines of business in which the *part* is engaged, *not* on the overall risk of the parent company on a consolidated basis. According to financial theory, the overall risk of a diversified company equals the market-value weighted average of the risks of its components, so selecting a sample concentrated in the regulated company's line of business is important. Met-Ed, Penelec, Penn Power, and West Penn are regulated electric companies, and there is currently available a relatively large sample of publicly-traded electric utilities whose primary business is in the regulated electric industry under cost of service regulation.

Q. Can you summarize how you selected the electric sample?

A. I formed the sample from the universe of publicly traded electric utilities as classified by the *Value Line Investment Survey Plus Edition*.[34] This resulted in an initial group of 51 companies. I then eliminated companies by applying additional selection

[34] The 51 companies are from *Value Line Investment Analyzer*, Accessed as of June 3, 2014.

criteria designed to remove companies with unique circumstances which may bias the cost of capital estimates.

Q. What additional selection criteria did you apply?

A. The companies must own substantial regulated assets, must not exhibit any signs of financial distress, and must not be involved in any substantial merger and acquisition ("M&A") activities[35] that could bias the estimation process. In general, this requires that companies have an investment grade credit rating, a high percentage of regulated electric assets (greater than 50 percent),[36] no significant merger activity in the past five years (dated from the point of analysis), no dividend cuts during the past five years, and no other activity that could cause the growth rates or beta estimates to be biased. I also require that each of the sample companies has more than $300 million in reported revenue in the past year (dated from the end of fiscal quarter used for capital structure data). Finally, I require that data from S&P or Moody's, *Value Line*, and Bloomberg—each widely known and utilized by investors—be available for all sample companies.

[35] This includes pending (but announced) M&A activity, but adjusts for M&A activity that does not appear to bias the beta estimates substantively, (such as small, spaced-out transactions, transactions involving multiple parties or parent drop-downs).

[36] I use the Edison Electric Institute's classification of electric utilities as Regulated (greater than 80 percent of total assets are regulated), Mostly Regulated (50 to 80 percent of total assets are regulated) or Diversified (less than 50% of total assets are regulated). My sample includes only electric utilities classified by EEI as Regulated or Mostly Regulated.

Q. Do any of the companies in your electric sample have a revenue decoupling mechanism?

A. Yes. Several of the companies in my comparable sample have a decoupling mechanism in place.[37] This means that these companies benefit from regulatory provisions allowing them to recover their fixed costs independently of volumetric charges: if the utilities' customers use less electricity than was forecast, the decoupling mechanism ensures that the utilities can recover their cost despite the decrease in variable revenues.

B. Characteristics of the Electric Sample Companies

Q. What are the characteristics of the sample of electric utility companies you have chosen?

A. The electric sample is comprised of regulated companies whose primary source of revenues and majority of assets are in the regulated portion of the electric industry. The final sample consists of the 33 electric utilities listed in Table 2 below.

Q. How does the sample compare to Met-Ed, Penelec, Penn Power, and West Penn?

A. The Table 2 below reports the sample companies' total annual revenues in 2013 and the percentage of their assets devoted to regulated electric operations according to EEI's classifications of electric utilities as being either regulated ("R"), having greater than 80 percent regulated electric assets or mostly regulated ("MR"), having 50-80 percent regulated electric assets. Table 2 also displays the Market Capitalization, the

[37] See Edison Electric Institute, "Alternative Regulation for Evolving Utility Challenges: An Updated Survey," January 2013 for a compilation of decoupling mechanisms by company and state.

S&P Credit Rating in 2014, and the average long-term (5-year) earnings growth rate estimate from Bloomberg for all of the companies in the electric sample.

The Companies averaged revenue of approximately $1.1 billion in 2013.[38] In comparison, the average sample company had $6.6 billion in revenue in 2013; the median company in the sample had $4.5 billion in revenue.[39] Met-Ed, Penelec, Penn Power, and West Penn's parent company, FirstEnergy Corp., had $14.9 billion in revenue for 2013. Thus, while the Companies individually are somewhat smaller than the average sample company, their status as subsidiaries of a larger firm mitigates any additional risk of financial distress that their size might otherwise pose relative to the sample.

FirstEnergy Corp., Met-Ed, Penelec, Penn Power, and West Penn all have S&P credit ratings of BBB-, which is slightly lower than the sample's average credit rating.[40]

[38] Ibid.

[39] The revenue figures in **Error! Reference source not found.** are the reported annual revenue in the calendar year ending December 31st, 2013.

[40] Table 2 reports the credit rating without the +/- designation that S&P assigns to some companies.

Electric Sample

Company	Annual Revenue (Year End, 2013) ($MM)	Regulated Assets	Market Cap. (2013) ($MM)	S&P Credit Rating (2014)	Long Term Growth Est
[1]	[2]	[3]	[4]	[5]	[6]
ALLETE Inc	1,018	R	2,006	BBB	6.0%
Ameren Corp	5,838	R	8,561	BBB	7.3%
American Electric Power Co Inc	15,357	R	22,132	BBB	5.7%
Black Hills Corp	1,276	R	2,258	BBB	7.0%
CMS Energy Corp	6,566	R	6,930	BBB	5.7%
Cleco Corp	1,097	R	2,760	BBB	7.0%
CenterPoint Energy Inc	8,106	MR	9,669	A	5.0%
Dominion Resources Inc/VA	13,120	MR	36,632	A	6.1%
DTE Energy Co	9,661	R	11,582	BBB	5.5%
Consolidated Edison Inc	12,354	R	15,703	A	3.8%
El Paso Electric Co	890	R	1,379	BBB	5.3%
Edison International	12,581	R	14,789	BBB	3.7%
Entergy Corp	11,391	R	10,809	BBB	0.1%
Great Plains Energy Inc	2,446	R	3,644	BBB	5.0%
Hawaiian Electric Industries Inc	3,237	MR	2,535	BBB	3.4%
IDACORP Inc	1,246	R	2,582	BBB	4.0%
Alliant Energy Corp	3,277	R	5,597	A	5.0%
MGE Energy Inc	591	MR	1,280	AA	4.0%
NextEra Energy Inc	15,136	MR	35,919	A	6.5%
OGE Energy Corp	2,868	MR	6,611	A	5.0%
Otter Tail Corp	893	MR	1,035	BBB	6.0%
PG&E Corp	15,598	R	18,154	BBB	5.8%
Public Service Enterprise Group Inc	9,968	MR	15,840	BBB	5.2%
Pinnacle West Capital Corp	3,455	R	5,721	A	4.5%
Portland General Electric Co	1,810	R	2,305	BBB	6.8%
SCANA Corp	4,495	MR	6,542	BBB	5.0%
Southern Co/The	17,087	R	35,237	A	3.9%
Sempra Energy	10,557	MR	21,283	BBB	6.9%
Integrys Energy Group Inc	5,635	R	4,191	A	5.0%
Vectren Corp	2,491	MR	2,820	A	4.5%
Wisconsin Energy Corp	4,519	R	9,131	A	4.7%
Westar Energy Inc	2,371	R	3,996	BBB	4.1%
Xcel Energy Inc	10,915	R	13,692	A	5.0%

Sources and Notes:
[2] Bloomberg as of June 3, 2014
[3] Key R - Regulated (More than 80% of assets regulated)
MR - Mostly Regulated (50%-80% of assets regulated)
Source: EEI. See Table MJV-2
[4] See Table MJV-3, Panels A through AG
[5] Bloomberg as of June 3, 2014
[6] See Table MJV-5

Table 2

Like many of the sample companies, Met-Ed, Penelec, Penn Power, and West Penn benefit from certain regulatory policies that reduce regulatory lag, including a quarterly adjustment and true-up mechanism for default service power prices.[41] The Companies, for the most part, are not permitted to include construction work in progress (CWIP) in rate base,[42] but have received approval from the PUC for a dedicated Smart Meter Technologies Charge to recover capital expenditures associated with the mandatory installation of advanced metering infrastructure (AMI) within their service territories.[43] Cost-tracking mechanisms such as these also have precedents in states affecting several of the sample companies.[44] However, unlike some of the sample companies, Met-Ed, Penelec, Penn Power, and West Penn do not have revenue decoupling mechanisms or lost revenue adjustment mechanisms (LRAM) in place; nor do they operate in a jurisdiction that employs "fixed variable" pricing for rate design, as some sample companies do.[45]

Q. How does the business risk of Met-Ed, Penelec, Penn Power, and West Penn compare to that of the sample companies?

A. Like the sample companies, the Companies' business is concentrated in regulated electric service, and Met-Ed, Penelec, Penn Power, and West Penn also have some

[41] SNL Regulatory Research Associates

[42] Edison Electric Institute, "Alternative Regulation for Evolving Utility Challenges: An Updated Survey," January 2013.

[43] SNL Regulatory Research Associates

[44] Edison Electric Institute, "Alternative Regulation for Evolving Utility Challenges: An Updated Survey," January 2013.

[45] Ibid.

regulatory mechanisms in place that are comparable to those of the proxy group companies.

The Companies' operations focus predominantly on electric distribution, and unlike many of the sample companies, Met-Ed, Penelec, Penn Power, and West Penn do not own generation assets. However, since their distribution service is cost-of-service regulated, and they are permitted to true-up their purchase power costs, they are of similar business risk to the sample.

In terms of risk factors that increase the Companies' business risks relative to the sample, I have already noted that all have S&P corporate credit ratings of BBB-, below the median of 'BBB' for the sample, indicating an elevated credit risk. I have likewise noted that Met-Ed, Penelec, Penn Power, and West Penn are individually smaller—both in terms of revenue and assets—than the average sample company. Smaller companies typically have a higher cost of capital, even after adjusting for their level of systematic market risk (as measured by beta in the CAPM and ECAPM).

Regulatory policy also plays a role in the business risk of the Companies. In the current environment of low electric demand growth, the fact that Met-Ed, Penelec, Penn Power, and West Penn do not have a revenue decoupling mechanism or a fixed variable pricing policy places them at increased risk of under-recovering their cost of service relative to some sample companies that benefit from such mechanisms. This risk is especially acute for the Companies because Pennsylvania allows competitive retail choice, which could potentially decrease the variable revenues of electric

distribution companies such as Met-Ed, Penelec, Penn Power, and West Penn. Pennsylvania also has Energy Efficiency Resource Standards that require electric distribution utilities to reduce energy consumption by 2.3 percent cumulatively over the 2014-2016 period.[46] Thus, to the extent that the Companies recover some of their fixed costs through per-kWh charges to their customers (i.e., do not benefit from decoupling or fixed-variable pricing), they will be at substantial risk for under-recovery.

In consideration of these and other factors, I believe Met-Ed, Penelec, Penn Power, and West Penn are of somewhat higher than average business risk relative to the sample companies.

C. Capital Structure

Q. What regulatory capital structure are the Companies requesting in this proceeding?

A. Met-Ed, Penelec, Penn Power, and West Penn have each proposed a regulatory capital structure consisting of approximately 50 percent equity and 50 percent debt,[47] as further explained by Mr. Steven R. Staub in Met-Ed/Penelec/Penn Power/ West Penn Statement No. 10. This capital structure is consistent with the book value capital structures of my sample companies. The sample averages about 49 percent equity and 51 percent debt on a book basis. The highest percentage of book equity for the companies in the sample is 60 percent equity (MGE Energy Inc.) and the

[46] American Council for an Energy-Efficient Economy State and Local Policy Database. http://database.aceee.org/state/pennsylvania

[47] By regulatory capital structure, I mean the capital structure used to set rates in this proceeding.

lowest is 31 percent equity (CMS Energy Corp.). My recommended range for ROE is a function of the requested capital structure, the sample average ATWACC estimates and the relative risk of the Companies compared to the sample.

V. COST OF CAPITAL ESTIMATES

Q. How do you estimate the sample companies' costs of equity?

A. As noted earlier, I apply two general methodologies—risk positioning and DCF—both of which are standard ways of estimating a company's cost of equity. For my CAPM (risk positioning) based estimates, I consider a range of sensitivities to reflect well-documented empirical deficiencies in the CAPM when used in conjunction with an equity market index. These sensitivities are called the Empirical CAPM. I also report results generated by two versions of the DCF approach: the single-stage and the multistage DCF models.

A. The CAPM-Based Estimates

Q. Can you explain the CAPM?

A. Modern models of capital market equilibrium express the cost of equity as the sum of a risk-free rate and a market risk premium. The CAPM is the longest-standing and most widely used of these theories. To implement the model requires specification of (1) the current values of the benchmarks that determine the Security Market Line (see Figure 1 above); (2) the relative risk of a security or investment; and (3) how the benchmarks combine to produce the Security Market Line. Given these specifications, the company's cost of capital can be calculated based on its relative

risk. Specifically, the CAPM states that the cost of capital for an investment, *S* (e.g., a particular common stock), is given by the following equation:

$$r_S = r_f + \beta_S \times MRP \qquad (2)$$

where r_s is the cost of capital for investment *S*; r_f is the risk-free rate; β_S is the beta risk measure for the investment *S*; and *MRP* is the market risk premium. The CAPM relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities. It says that the Security Market Line starts at the risk-free interest rate (that is the return on a zero-risk security, the y-axis intercept in Figure 1, equals the risk-free interest rate). Further, it says that the risk premium of a security over the risk-free rate equals the product of the beta of that security and the risk premium on a value-weighted portfolio of all investments, which by definition has average risk.

1. The Risk-free Interest Rate

Q. What interest rates do your procedures require?

A. Modern capital market theories of risk and return (e.g., the theoretical version of the CAPM as originally developed) use the short-term risk-free rate of return as the starting benchmark, but regulatory bodies frequently use a version of the risk positioning model that is based upon the long-term risk-free rate. In this proceeding, I rely upon the long-term version of the risk positioning model. Accordingly, the implementation of my procedures requires use of long-term U.S. Treasury bond interest rates. I obtain this information from the 15-day average yield on long-term Treasury bonds as reported by Bloomberg for the period ending June 3, 2014.

Q. Why didn't you use the version of the CAPM that relies on the short-term risk-free rate in this proceeding?

A. Short-term Treasury bill yields remain at artificially low levels due to the efforts of the Fed to stimulate the economy. As a result, the risk positioning required ROE estimates using the short-term Treasury bill yields as the risk-free interest rate are unreasonably low. For example, the estimates are sometimes less than the corresponding company's current market cost of debt, which is unreasonable. A company's equity is always riskier than its debt and requires a higher return, because debt holders are always paid before equity holders in the event of bankruptcy or other financial distress.

2. The Market Risk Premium

Q. Why is a risk premium necessary?

A. Experience (e.g., the recent credit crisis in stock markets worldwide and the U.S. market's October Crash of 1987) demonstrates that shareholders, even well diversified shareholders, are exposed to enormous risks. By investing in stocks instead of risk-free government Treasury bills, investors subject themselves not only to the risk of earning a return well below that which they expected in any year but also to the risk that they might lose much of their initial capital. This is fundamentally why investors demand a risk premium.

Q. Has the estimate of the MRP been controversial over the recent past?

A. Yes. Historically, it was generally accepted that the appropriate method to estimate the MRP was to consider the historical average realized return on the market minus

the return on a risk-free asset over as long a series of time as possible; however, this procedure came under attack during the period of time generally referred to as the "tech bubble" when the stock markets in the U.S. reached very high valuation levels relative to traditional metrics of value. The period of the tech bubble also resulted in the average realized return on the market increasing to a very high level. Attempts to explain the high stock market valuation levels centered on the hypothesis that the MRP must be dramatically lower than previously believed, but this hypothesis conflicted with the fact that realized returns over the period were very high. The result was an academic debate on the level of the forward-looking MRP and how best to estimate it—a debate that has still not been fully resolved. As discussed in *Section III*, the effects of the recession still affect investors' required returns through a MRP that remains higher than the historical average realized return on the market minus the return on the risk-free asset prior to the crisis.

Q. How do these factors affect the cost of capital for the Companies?

A. The Companies invest in long-lived assets which cannot be easily liquidated (they are hard physical assets that once put in place cannot be moved). Investment is a voluntary activity, and investors generally require a return that is consistent with the risk they take on; therefore, it could damage the ability to access capital if investors view the allowed rate of return as lower than the required rate of return. The problem is not avoided for companies that are 100 percent owned subsidiaries because the parent company must consider the opportunity cost of capital when making investments. Investors expect managers to invest in projects which provide expected returns at least equal to the cost of capital.

Q. What is your conclusion regarding the MRP?

A. Historically, much of the controversy over market risk premium centered on various reasons that it may not be as high as frequently estimated. Although none of the arguments was completely persuasive in and of itself, I generally gave some weight to these issues in past testimony and reduced my estimate of the MRP. Conversely, recent events have strongly suggested an increase in the MRP from its previous levels. I would typically consider an MRP of 6.5 percent over the long-bond rate as reasonable based on my review of the relevant academic literature. However, current market conditions suggest that a value of 7.5 percent could be more appropriate at this time. Therefore, I include two analyses: one using an MRP of 6.5 and the other using an MRP of 7.5 percent.

3. Beta

Q. Can you more fully explain beta?

A. The basic idea behind beta is that risks that cannot be diversified away in large portfolios matter more than those that can be eliminated by diversification. Beta is a measure of the risks that cannot be eliminated by diversification. That is, it measures the "systematic" risk of a stock—the extent to which a stock's value fluctuates more or less than average when the market fluctuates.

Diversification is a vital concept in the study of risk and return. (Harry Markowitz won a Nobel Prize for work showing just how important it was.) Over the long run, the rate of return on the stock market has a very high standard deviation, on the order

of 20 percent per year.[48] Many individual stocks have much higher standard deviations than this. The stock market's standard deviation is "only" about 15-20 percent because when stocks are combined into portfolios, some of the risk of individual stocks is eliminated by diversification. Some stocks go up when others go down, and the average portfolio return—whether positive or negative—is usually less extreme than that of many individual stocks within it. The fact that the market's actual annual standard deviation is so large means that, in practice, the returns on stocks are positively correlated with one another, and to a material degree. The reason is that many factors that make a particular stock go up or down also affect other stocks. Examples include the state of the economy, the balance of trade, and inflation. Thus some risk is "non-diversifiable" in that even a well-diversified portfolio of stocks will experience changes in value caused by these shared risk factors. Single-factor equity risk premium models (such as the CAPM) are based upon the assumption that all of the systematic factors that affect stock returns can be considered simultaneously, through their impact on one factor: the market portfolio. Other models derive somewhat less restrictive conditions under which several factors might be individually relevant.

Again, the basic idea behind all of these models is that risks that cannot be diversified away in large portfolios matter more than those that can be eliminated by diversification, because there are a large number of large portfolios whose managers

[48] See Brealey, Myers and Allen (2011), *Principles of Corporate Finance, 10th Edition*, McGraw-Hill Irwin, New York, p. 166.

actively seek the best risk-reward tradeoffs available. (Of course, undiversified investors would like to get a premium for bearing diversifiable risk, but they cannot.)

Q. What does a particular value of beta signify?

A. By definition, a stock with a beta equal to 1.0 has average non-diversifiable risk: it goes up or down by 10 percent on average when the market goes up or down by 10 percent. Stocks with betas above 1.0 exaggerate the swings in the market: stocks with betas of 2.0 tend to fall 20 percent when the market falls 10 percent, for example. Stocks with betas below 1.0 are less volatile than the market. A stock with a beta of 0.5 will tend to rise 5 percent when the market rises 10 percent.

Q. How is beta measured?

A. The usual approach to calculating beta is a statistical comparison of the sensitivity of a stock's (or a portfolio's) return to the market's return. Many investment services report betas, including Bloomberg and the *Value Line Investment Survey*. Betas are not always calculated in precisely the same way, and therefore must be used with a degree of caution. However, the basic principle that a high beta indicates a risky stock has long been widely accepted by both financial theorists and investment professionals, and is universally reflected in all calculations of beta. In my analyses for these proceedings, I present results using the beta estimates reported by *Value Line*.

Q. What are the betas that you used for the sample companies?

A. Table 3 below lists the *Value Line* betas I used to calculate my risk-positioning estimates of the cost of capital for the sample of regulated electric utilities.

Valueline Betas	
Company	**Value Line Betas**
ALLETE Inc	0.80
Ameren Corp	0.85
American Electric Power Co Inc	0.70
Black Hills Corp	0.90
CMS Energy Corp	0.70
Cleco Corp	0.70
CenterPoint Energy Inc	0.85
Dominion Resources Inc/VA	0.75
DTE Energy Co	0.85
Consolidated Edison Inc	0.65
El Paso Electric Co	0.70
Edison International	0.80
Entergy Corp	0.75
Great Plains Energy Inc	0.90
Hawaiian Electric Industries Inc	0.85
IDACORP Inc	0.80
Alliant Energy Corp	0.80
MGE Energy Inc	0.70
NextEra Energy Inc	0.75
OGE Energy Corp	0.85
Otter Tail Corp	0.95
PG&E Corp	0.60
Public Service Enterprise Group Inc	0.80
Pinnacle West Capital Corp	0.75
Portland General Electric Co	0.80
SCANA Corp	0.75
Southern Co/The	0.60
Sempra Energy	0.80
Integrys Energy Group Inc	1.05
Vectren Corp	0.75
Wisconsin Energy Corp	0.70
Westar Energy Inc	0.80
Xcel Energy Inc	0.65
Average	0.78
Sources and Notes: From Valueline Investment Analyzer as of June 3, 2014.	

Table 3

4. The Empirical CAPM

Q. What other equity risk premium model do you use?

A. Empirical research has long shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted. A number of variations on the original CAPM theory have been proposed to explain this finding, but the observation itself can also be used to estimate the cost of capital directly, using beta to measure relative risk by making a direct empirical adjustment to the CAPM.

This second model makes use of these empirical findings. It estimates the cost of capital with the equation,

$$r_S = r_f + \alpha + \beta_S \times (MRP - \alpha) \qquad (3)$$

where α is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are defined as above. I label this model the Empirical Capital Asset Pricing Model, or "ECAPM." The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line in Figure 1 earlier in my testimony which results in a Security Market Line that more closely matches the results of empirical tests. In other words, the ECAPM produces more accurate predictions of eventual realized risk premiums than does the CAPM.

Q. Why is it appropriate to use the Empirical CAPM?

A. The CAPM has not generally performed well as an empirical model, but its shortcomings are directly addressed by the ECAPM. Specifically, the ECAPM recognizes the consistent empirical observation that the CAPM underestimates (overestimates) the cost of capital for low (high) beta stocks. In other words, the ECAPM is based on recognizing that the actual observed risk-return line is flatter and has a higher intercept than that predicted by the CAPM. The alpha parameter (α) in the ECAPM adjusts for this fact, which has been established by repeated empirical tests of the CAPM. The difference between the CAPM and the type of relationship identified in the empirical studies is depicted in Figure 11 below.

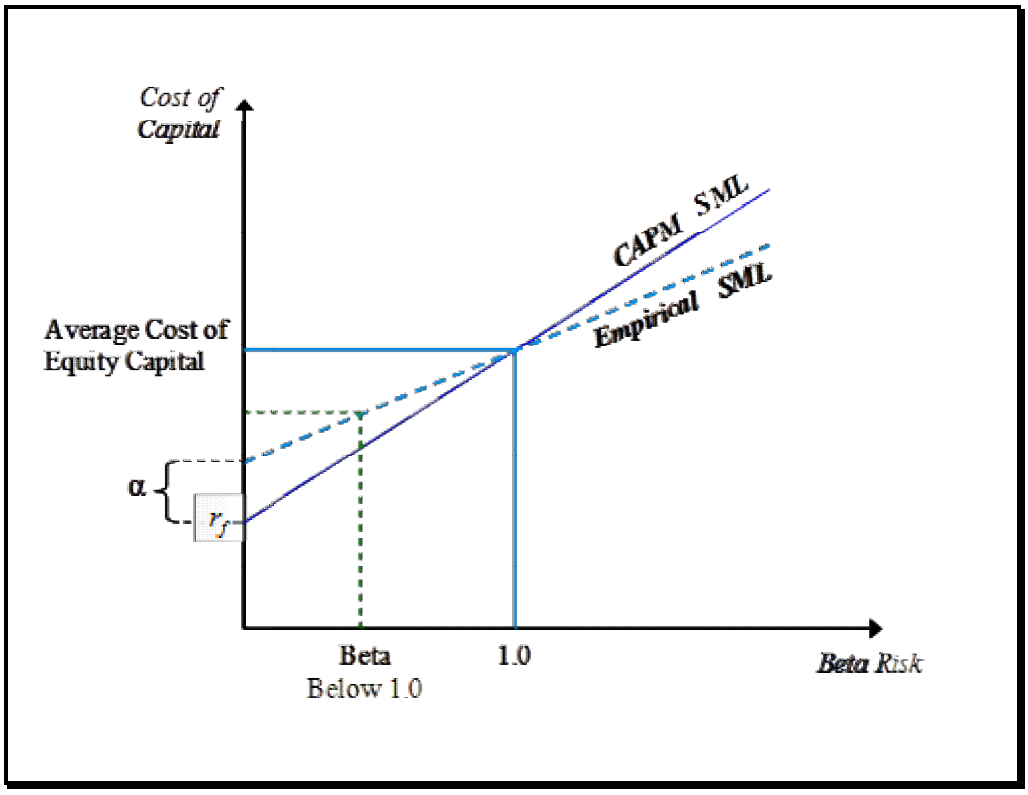


Figure 11: The Empirical Security Market Line

Q. What are the parameters of the two scenarios you considered in your risk positioning analyses?

A. The parameters for the two scenarios are displayed in Table 4 below. The motivation for the scenarios is the empirical observation that the yield spread is higher than normal. The increased yield spread could be the result of an increase in the MRP or downward pressure on the yield of risk-free bonds due to a flight to quality or a combination of the two factors. Therefore, I reduce the risk-free rate for use with a higher estimate of the MRP as illustrated in Table 4**.** In other words, the approximately 25 bps increase in the yield spread is allocated between an increase in the MRP and the downward pressure on the risk-free rate according to the method described above. The more of the bps increase in yield spread that is allocated to the under estimation of the risk-free rate, the less that the MRP is increased and vice versa.

Parameters for Scenarios in Risk Positioning Analyses

	Scenario 1	Scenario 2
Risk-Free Interest Rate	3.35%	3.10%
Market Risk Premium	6.50%	7.50%

Table 4

Q. Can you summarize the results from applying the CAPM and ECAPM methodologies to the sample?

A. The results of the risk positioning analyses (the CAPM and the ECAPM) are presented in Table 5 using *Value Line's* estimated betas for the sample of electric companies. (The underlying calculations are also presented in Exhibit MJV-1.) For the ECAPM, there are two sensitivities: $\alpha = 0.5$ percent and $\alpha = 1.5$ percent. The

columns display the scenario results for MRP estimates of 6.5, and 7.5 percent. The long-term risk-free interest rate as of June 3, 2014 was 3.10 percent before adjustments for the downward pressure on government yields due to the flight to safety. The ROE estimates in Table 5 reflect the ATWACC estimates adjusted for differences in capital structure between the sample companies and the Companies. Specifically, the ROE associated with each method and a capital structure with 50 percent equity is displayed in Table 5.

Return on Equity Summary and Sensitivity Analysis
Using Value Line Betas

Estimated Return on Equity	Scenario 1 [1]	Scenario 2 [2]
Full Sample		
CAPM	8.7%	9.2%
ECAPM (α = 0.5%)	8.8%	9.3%
ECAPM (α = 1.5%)	9.0%	9.6%

Sources and Notes:
Scenario 1: Long-Term Risk Free Rate of 3.35%, Long-Term Market Risk Premium of 6.50%.
Scenario 2: Long-Term Risk Free Rate of 3.10%, Long-Term Market Risk Premium of 7.50%.

Table 5

Q. What conclusions do you draw from the equity risk premium results (i.e., CAPM and ECAPM)?

A. Of the equity risk premium results, the CAPM values deserve the least weight, because this method does not adjust for the empirical finding that the cost of capital is less sensitive to beta than predicted by the CAPM (which my testimony and exhibits consider by using the ECAPM). Conversely, the ECAPM numbers deserve more weight, because this method adjusts for the empirical findings. The results for

Scenario 1 do not fully adjust for the still-elevated market risk premium in the capital markets and deserve less weight than those for Scenario 2. Focusing on the ECAPM results for the sample, the results range from 8.8 percent to 9.6 percent.

B. The DCF Based Estimates

Q. Can you describe the discounted cash flow approach to estimating the cost of equity?

A. The DCF model takes the first approach to cost of capital estimation described above, i.e., to attempt to estimate the cost of capital in one step instead of estimating the cost of capital for the entire market and then determining the cost of capital for an individual investment. The DCF method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P = \frac{D_1}{(1+r)} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \qquad (4)$$

where "*P*" is the market price of the stock; "D_i" is the dividend cash flow expected at the end of period *i*; "*r*" is the cost of capital; and "*T*" is the last period in which a dividend cash flow is to be received. The formula just says that the stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received.

Most DCF applications go even further, and make very strong assumptions that yield a simplification of the standard formula, which then can be rearranged to estimate the

cost of capital. Specifically, if investors expect a dividend stream that will grow *forever* at a steady rate, then the market price of the stock will be given by a very simple formula,

$$P = \frac{D_1}{(r - g)} \qquad (5)$$

where "D_1" is the dividend expected at the end of the first period, "g" is the perpetual growth rate, and "P" and "r" are the market price and the cost of capital, as before. Equation (5) is a simplified version of equation (4) that can be solved to yield the well-known "DCF formula" for the cost of capital:

$$\begin{aligned} r &= \frac{D_1}{P} + g \\ &= \frac{D_0 \times (1+g)}{P} + g \end{aligned} \qquad (6)$$

where "D_0" is the current dividend, which investors expect to increase at rate g by the end of the next period, and the other symbols are defined as before. Equation (6) says that if equation (5) holds, the cost of capital equals the expected dividend yield plus the (perpetual) expected future growth rate of dividends. I refer to this as the simple DCF model. Of course, the "simple" model is simple because it relies on very strong assumptions.[49]

Q. Are there other versions of the DCF models in addition to the "simple" one?

A. Yes. One such alternative version is the multistage DCF model. In its "simple" or constant growth rate formulation, the DCF model requires that dividends and earnings

[49] In this context "strong" means assumptions that are unlikely to reflect reality but that also are not expected to have a large effect on the estimate.

grow at a constant rate for companies that earn their cost of capital on average.[50] It is inconsistent with the theory on which this formulation is based to have varying growth rates in earnings and dividends. If, however, the growth rates for dividends and earnings were expected to vary over some number of years before settling down into a constant growth period, then it would be appropriate to utilize a multistage DCF model. In the multistage model, earnings and dividends can grow at different rates, but must grow at the same rate in the final, constant growth rate period.

Q. What is your assessment of the DCF model?

A. The DCF approach is grounded in solid finance theory. It is widely accepted by regulatory commissions and provides useful insight regarding the cost of capital based on forward-looking metrics. DCF estimates of the cost of capital complement those of the CAPM and the ECAPM because the two methods rely on different inputs and assumptions. The DCF method is particularly valuable in the current economic environment, because of the effects on capital market conditions of the Fed's efforts to maintain interest rates at historically low levels which bias the CAPM and ECAPM estimates downward.

However, I recognize that the DCF model, like most models, relies upon assumptions that do not always correspond to reality. For example, the DCF approach assumes

[50] Why must the two growth rates be equal in a steady-growth DCF model? Think of earnings as divided between reinvestment, which funds future growth, and dividends. If dividends grow faster than earnings, then there is less investment and slower growth each year. Sooner or later dividends will equal earnings. At that point, growth is zero because nothing is being reinvested (dividends are constant). If dividends grow more slowly than earnings, each year a bigger fraction of earnings are reinvested. That makes for ever faster growth. Both scenarios contradict the steady-growth assumption. So if you observe a company with different expectations for dividend and earnings growth, you know the company's stock price and its dividend growth forecast are inconsistent with the assumptions of the steady-growth DCF model.

that the variant of the present value formula that is used matches the variations in investor expectations for the growth of dividends, and that the growth rate(s) used in that formula match current investor expectations. Less frequently noted conditions, such as the value of real options incorporated in a company's market price, may create issues that the DCF model does not incorporate. Nevertheless, under current economic conditions, because of its forward looking nature, the strengths of the DCF method far outweigh any weaknesses the method may have.

Q. What growth rate information do you use?

A. The first step in my DCF analysis (either constant growth or multistage formulations) is to examine a sample of investment analysts' forecasted earnings growth rates from Bloomberg and from *Value Line* for companies in the electric sample. For the long-term growth rate for the final, constant-growth stage of the multistage DCF estimates, I use the most recent long-run GDP growth forecast from Blue Chip Economic Indicators.[51]

Q. How do these growth rates correspond to the theoretical criteria you discuss above?

A. The constant-growth formulation of the DCF model, in principle, requires forecasted growth rates, but it is also necessary that the growth rates used go far enough out into the future so that it is reasonable to believe that investors expect a stable growth path afterwards. Under current economic conditions, I believe the forecasted growth rates of investment analysts provide the best available representation of the longer term, steady-state growth rate expectations of investors. Therefore, I feel these growth

[51] Blue Chip Economic Indicators, March 10, 2014.

parameters available to apply to the simple, constant-growth DCF model provide useful estimates of the cost of capital.

Q. Does the multistage DCF improve upon the simple DCF?

A. Potentially, but the multistage method assumes a particular smoothing pattern and a long-term growth rate afterwards. These assumptions may not be a more accurate representation of investor expectation than those of the simple DCF. The smoother growth pattern, for example, might be not be representative of investor expectations, in which case the multistage model would not increase the accuracy of the estimates. Indeed, amidst uncertainty in capital markets, assuming a simple constant growth rate may be preferable to attempting to model growth patterns in greater detail over multiple stages. While it is difficult to determine which set of assumptions comprises a closer approximation of the actual conditions of capital markets, I believe both forms of the DCF model provide useful information about the cost of capital.

Q. What are the relative strengths and weaknesses of the DCF and risk-positioning methodologies?

A. Current market conditions affect all cost of capital estimation models to some degree, but the DCF model has at least one advantage over the risk positioning models. Specifically, the DCF model reflects current market conditions more quickly because the market price of a company's stock changes daily. Dividend yields increase when market prices fall and reflect the increased cost of capital. The challenge for the DCF model is that the model requires forecasts of earnings growth rates that are based upon stable economic conditions which are required to satisfy the constant dividend

growth rate assumption. Although the dividend yield quickly reacts to changes in the market, the growth rate estimates may be less precise during times of market uncertainty because future growth rates may be more volatile. Nevertheless, because dividend yields and forecast growth rates change quickly, the DCF model is likely to better reflect investors' current cost of capital expectations than the CAPM and ECAPM which relies upon 5 years of historical data.

Q. What are the DCF estimates for the sample?

A. The corresponding DCF estimates for the sample are presented in Table 6. The ROE estimate is 10.9 percent for the single-stage model and 9.8 percent for the multistage model.

DCF Return on Equity Summary		
	DCF	
	Simple	Multi-stage
Full Sample		
Cost of Equity	10.9%	9.8%

Table 6

Q. What conclusions do you draw from the DCF analysis?

A. Although I made no adjustment for the current market turmoil for the DCF model, the DCF estimates are slightly higher than the upper end of the range of estimates from the risk positioning model displayed above in Table 5. (Recall that the ECAPM risk positioning estimates range from 8.8 percent to 9.6 percent when using *Value Line's* estimated betas). At this time, I believe that the DCF estimates indicate that the

estimates from Scenario 2 for the risk positioning model are more reliable than those from Scenario 1.

VI. CONCLUSIONS

Q. Can you summarize the evidence from the sample regarding the ROE for an electric utility of average risk?

A. Table 5 and Table 6 summarize the results of the analyses for the risk positioning and DCF models for the sample of electric utilities. The results from the CAPM are less reliable than the results from the ECAPM because they do not consider the consistent empirical evidence that the CAPM underestimates the cost of capital for low beta companies, such as Met-Ed, Penelec, Penn Power, and West Penn. Similarly, the results for Scenario 1 are not as reliable as those for Scenario 2 because Scenario 1 ignores the increased MRP resulting from the ongoing uncertainty in the capital markets. Based on the sample's cost of capital estimates, I believe a company of the Companies' business and financial risk should have an allowed ROE in the range 9.3 percent to 10.9 percent.

Q. What is your recommendation range of the ROE for the Companies?

A. For companies of comparable risk to Met-Ed, Penelec, Penn Power, and West Penn at a capital structure with approximately 50 percent equity, the cost of equity falls in the range of 9.3 percent to 10.9 percent. Because the upper end of the range is established by the estimates from the DCF model, I believe that the upper end of the range is more reliable at this time.

Q. Why doesn't your recommended range for the samples cover all of the estimates displayed in Table 5 and Table 6?

A. I provide an estimate of a reasonable range of required ROE for the sample, and the range of uncertainty is based upon all of the analyses I have done, placing relatively more weight on more reliable methodologies and estimates. I do not try to include all of the resulting estimates in the range because I regard some of the estimates as more reliable than others. For example, the estimates based upon the CAPM are not as reliable as those based upon the ECAPM because the CAPM estimates do not account for the empirical observation that low beta stocks have higher costs of capital than estimated by the CAPM, high beta stocks have lower costs of capital. Nor is it likely that the lowest estimates in the tables are as reliable as those in the upper end of the range because those estimates do not adequately consider the continued uncertainty in the financial markets.

Q. Is there any other reason to support an allowed ROE in the upper end of the 9.3 percent to 10.9 percent range?

A. Yes. It is important to maintain Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company's access to capital, and maintaining a solid credit rating and outlook is one important aspect to maintaining access to capital. Credit rating agencies are concerned about cash flows. A reduction in the allowed return on equity would signal a likely reduction in cash flow and put downward pressure on Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company's credit metrics, which are already on the borderline of investment

grade.[52] Maintaining a strong credit rating is particularly critical during a period forecast to have substantial capital investment for infrastructure. In addition, as the Fed continues to taper its bond purchases, one can expect that the cost of capital will increase although the pace of such an increase cannot be predicted with certainty. This means that estimates at the upper end of the range are more representative of the cost of capital expected over the next three years.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[52] Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company are rated Baa3 by Moodys, BBB by Fitch, and BBB- by S&P. These are the corporate (S&P) / issuer (Moody's and Fitch) credit ratings for the Companies.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. R-2014-2428745

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. R-2014-2428743

PENNSYLVANIA POWER COMPANY
DOCKET NO. R-2014-2428744

WEST PENN POWER COMPANY
DOCKET NO. R-2014-2428742

Exhibit MJV-1

List of Topics Addressed

Cost of Common Equity Capital

Table No. MJV-1

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Table No. MJV-1	Table of Contents
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Table No. MJV-3	Market Value of the Electric Sample
Table No. MJV-4	Capital Structure Summary
Table No. MJV-5	Estimated Growth Rates
Table No. MJV-6	DCF Cost of Equity of the Electric Sample
Table No. MJV-7	Overall After-Tax DCF Cost of Capital of the Electric Sample
Table No. MJV-8	DCF Cost of Equity at The Companies' Representative Capital Structure
Table No. MJV-9	Risk-Free Rates
Table No. MJV-10	Risk Positioning Cost of Equity of the Electric Sample
Table No. MJV-11	Overall After-Tax Cost of Capital of the Electric Sample
Table No. MJV-12	Risk Positioning Cost of Equity at The Companies' Representative Capital Structure

Table No. MJV-2

Electric Sample

Classification of Companies by Assets

Company	Company Category
ALLETE Inc	R
Ameren Corp	R
American Electric Power Co Inc	R
Black Hills Corp	R
CMS Energy Corp	R
Cleco Corp	R
CenterPoint Energy Inc	MR
Dominion Resources Inc/VA	MR
DTE Energy Co	R
Consolidated Edison Inc	R
El Paso Electric Co	R
Edison International	R
Entergy Corp	R
Great Plains Energy Inc	R
Hawaiian Electric Industries Inc	MR
IDACORP Inc	R
Alliant Energy Corp	R
MGE Energy Inc	MR
NextEra Energy Inc	MR
OGE Energy Corp	MR
Otter Tail Corp	MR
PG&E Corp	R
Public Service Enterprise Group Inc	MR
Pinnacle West Capital Corp	R
Portland General Electric Co	R
SCANA Corp	MR
Southern Co/The	R
Sempra Energy	MR
Integrys Energy Group Inc	R
Vectren Corp	MR
Wisconsin Energy Corp	R
Westar Energy Inc	R
Xcel Energy Inc	R

Sources and Notes:
Edison Electric Institute: "Stock Performance - Q4 2013 Financial Update"
R = Regulated (greater than 80 percent of total assets are regulated).
MR = Mostly Regulated (50 to 80 percent of total assets are regulated).
D = Diversified (less than 50 percent of total assets are regulated).

Table No. MJV-3

Market Value of the Electric Sample

Panel A: ALLETE Inc

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$1,343	$1,343	$1,201	$1,079	$976	$930	$827	[a]
Shares Outstanding (in millions) - Common	41	41	39	38	36	35	33	[b]
Price per Share - Common	$49	$48.45	$38.44	$37	$32	$27	$24	[c]
Market Value of Common Equity	$2,040	$2,006	$1,515	$1,378	$1,139	$966	$776	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$2,040	$2,006	$1,515	$1,378	$1,139	$966	$776	[f]= [d] + [e]
Market to Book Value of Common Equity	1.52	1.49	1.26	1.28	1.17	1.04	0.94	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$307	$307	$273	$277	$240	$226	$252	[j]
Current Liabilities	$230	$230	$283	$163	$159	$133	$151	[k]
Current Portion of Long-Term Debt	$27	$27	$85	$5	$13	$5	$10	[l]
Net Working Capital	$104	$104	$74	$119	$94	$98	$112	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	#N/A N/A	#N/A N/A	#N/A N/A	$1	$1	$2	$6	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,083	$1,083	$934	$858	$772	$696	$588	[p]
Book Value of Long-Term Debt	$1,110	$1,110	$1,018	$863	$785	$701	$599	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,132	$1,132	$1,144	$966	$797	$735	$562	
Carrying Amount	$1,110	$1,110	$1,018	$863	$785	$701	$599	
Adjustment to Book Value of Long-Term Debt	$22	$22	$126	$103	$12	$34	($37)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,132	$1,132	$1,144	$966	$797	$735	$562	[s] = [q] + [r].
Market Value of Debt	$1,132	$1,132	$1,144	$966	$797	$735	$562	[t] = [s].
MARKET VALUE OF FIRM	$3,172	$3,137	$2,658	$2,345	$1,935	$1,701	$1,338	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	64.32%	63.93%	56.98%	58.79%	58.84%	56.79%	58.02%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	35.68%	36.07%	43.02%	41.21%	41.16%	43.21%	41.98%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014.
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel B: Ameren Corp

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$6,544	$6,544	$6,616	$7,919	$7,730	$7,856	$6,963	[a]
Shares Outstanding (in millions) - Common	243	243	243	243	240	238	212	[b]
Price per Share - Common	$39	$35.29	$28.61	$29	$24	$23	$25	[c]
Market Value of Common Equity	$9,441	$8,561	$6,941	$7,070	$5,809	$5,360	$5,213	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$9,441	$8,561	$6,941	$7,070	$5,809	$5,360	$5,213	[f]= [d] + [e]
Market to Book Value of Common Equity	1.44	1.31	1.05	0.89	0.75	0.68	0.75	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,972	$1,972	$3,596	$2,295	$2,890	$2,842	$2,608	[j]
Current Liabilities	$2,461	$2,461	$2,686	$1,785	$1,888	$1,711	$3,077	[k]
Current Portion of Long-Term Debt	$534	$534	$355	$179	$155	$204	$380	[l]
Net Working Capital	$45	$45	$1,265	$689	$1,157	$1,335	($89)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$368	$368	$0	$148	$269	$20	$1,174	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$89	[o] = See Sources and Notes.
Long-Term Debt	$5,504	$5,504	$5,802	$6,677	$7,313	$7,941	$6,554	[p]
Book Value of Long-Term Debt	$6,038	$6,038	$6,157	$6,856	$7,468	$8,145	$7,023	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$6,584	$6,584	$7,728	$7,800	$7,661	$7,719	$6,144	
Carrying Amount	$6,038	$6,038	$6,981	$6,856	$7,008	$7,317	$6,934	
Adjustment to Book Value of Long-Term Debt	$546	$546	$747	$944	$653	$402	($790)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$6,584	$6,584	$6,904	$7,800	$8,121	$8,547	$6,233	[s] = [q] + [r].
Market Value of Debt	$6,584	$6,584	$6,904	$7,800	$8,121	$8,547	$6,233	[t] = [s].
MARKET VALUE OF FIRM	$16,025	$15,145	$13,845	$14,870	$13,930	$13,907	$11,446	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	58.92%	56.53%	50.14%	47.54%	41.70%	38.54%	45.55%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	41.08%	43.47%	49.86%	52.46%	58.30%	61.46%	54.45%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel C: American Electric Power Co Inc

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$16,085	$16,085	$15,237	$14,664	$13,622	$13,140	$10,693	[a]
Shares Outstanding (in millions) - Common	488	488	486	483	481	478	426	[b]
Price per Share - Common	$52	$45.37	$40.59	$36	$31	$29	$24	[c]
Market Value of Common Equity	$25,511	$22,132	$19,713	$17,516	$14,752	$13,639	$10,234	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$25,511	$22,132	$19,713	$17,516	$14,752	$13,639	$10,234	[f]= [d] + [e]
Market to Book Value of Common Equity	1.59	1.38	1.29	1.19	1.08	1.04	0.96	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$60	$61	$61	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$60	$61	$61	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$4,310	$4,310	$4,589	$4,182	$5,016	$4,756	$3,775	[j]
Current Liabilities	$6,112	$6,112	$6,823	$6,611	$6,518	$5,327	$6,297	[k]
Current Portion of Long-Term Debt	$1,549	$1,549	$2,171	$1,433	$1,309	$1,741	$447	[l]
Net Working Capital	($253)	($253)	($63)	($996)	($193)	$1,170	($2,075)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$757	$757	$981	$1,650	$1,346	$126	$1,976	[n]
Adjusted Short-Term Debt	$253	$253	$63	$996	$193	$0	$1,976	[o] = See Sources and Notes.
Long-Term Debt	$16,828	$16,828	$15,586	$15,083	$15,502	$15,757	$15,536	[p]
Book Value of Long-Term Debt	$18,630	$18,630	$17,820	$17,512	$17,004	$17,498	$17,959	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$19,672	$19,672	$20,907	$19,259	$18,285	$18,479	$15,113	
Carrying Amount	$18,377	$18,377	$17,757	$16,516	$16,811	$17,498	$15,983	
Adjustment to Book Value of Long-Term Debt	$1,295	$1,295	$3,150	$2,743	$1,474	$981	($870)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$19,925	$19,925	$20,970	$20,255	$18,478	$18,479	$17,089	[s] = [q] + [r].
Market Value of Debt	$19,925	$19,925	$20,970	$20,255	$18,478	$18,479	$17,089	[t] = [s].
MARKET VALUE OF FIRM	$45,436	$42,057	$40,683	$37,771	$33,290	$32,179	$27,384	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	56.15%	52.62%	48.45%	46.37%	44.31%	42.38%	37.37%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	0.18%	0.19%	0.22%	[w] = [i] / [u].
Debt - Market Value Ratio	43.85%	47.38%	51.55%	53.63%	55.51%	57.43%	62.40%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel D: Black Hills Corp

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$1,308	$1,308	$1,233	$1,209	$1,100	$1,085	$1,051	[a]
Shares Outstanding (in millions) - Common	44	44	44	44	39	39	39	[b]
Price per Share - Common	$57	$50.75	$34.52	$30	$27	$22	$20	[c]
Market Value of Common Equity	$2,522	$2,258	$1,526	$1,327	$1,044	$867	$778	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$2,522	$2,258	$1,526	$1,327	$1,044	$867	$778	[f]= [d] + [e]
Market to Book Value of Common Equity	1.93	1.73	1.24	1.10	0.95	0.80	0.74	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$345	$345	$405	$759	$684	$625	$800	[j]
Current Liabilities	$378	$378	$735	$878	$794	$645	$1,254	[k]
Current Portion of Long-Term Debt	$0	$0	$104	$2	$5	$35	$2	[l]
Net Working Capital	($33)	($33)	($226)	($117)	($104)	$15	($452)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$83	$83	$277	$345	$249	$165	$704	[n]
Adjusted Short-Term Debt	$33	$33	$226	$117	$104	$0	$452	[o] = See Sources and Notes.
Long-Term Debt	$1,397	$1,397	$939	$1,280	$1,186	$1,016	$501	[p]
Book Value of Long-Term Debt	$1,430	$1,430	$1,269	$1,400	$1,296	$1,051	$955	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,491	$1,491	$1,232	$1,464	$1,291	$1,124	$456	
Carrying Amount	$1,397	$1,397	$1,043	$1,283	$1,191	$1,051	$503	
Adjustment to Book Value of Long-Term Debt	$94	$94	$189	$181	$99	$73	($47)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,525	$1,525	$1,457	$1,581	$1,395	$1,124	$908	[s] = [q] + [r].
Market Value of Debt	$1,525	$1,525	$1,457	$1,581	$1,395	$1,124	$908	[t] = [s].
MARKET VALUE OF FIRM	$4,046	$3,783	$2,983	$2,908	$2,439	$1,991	$1,687	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	62.32%	59.70%	51.15%	45.64%	42.81%	43.55%	46.14%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	37.68%	40.30%	48.85%	54.36%	57.19%	56.45%	53.86%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel E: CMS Energy Corp

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$3,454	$3,454	$3,194	$3,028	$2,793	$2,602	$2,476	[a]
Shares Outstanding (in millions) - Common	266	266	264	254	250	228	226	[b]
Price per Share - Common	$29	$26.04	$23.12	$19	$16	$13	$8	[c]
Market Value of Common Equity	$7,798	$6,930	$6,105	$4,932	$4,109	$2,978	$1,755	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$7,798	$6,930	$6,105	$4,932	$4,109	$2,978	$1,755	[f]= [d] + [e]
Market to Book Value of Common Equity	2.26	2.01	1.91	1.63	1.47	1.14	0.71	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$239	$243	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$239	$243	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$2,526	$2,526	$2,422	$2,565	$2,759	$2,742	$2,827	[j]
Current Liabilities	$1,945	$1,945	$1,797	$2,338	$2,021	$1,954	$1,863	[k]
Current Portion of Long-Term Debt	$562	$562	$541	$1,057	$750	$694	$514	[l]
Net Working Capital	$1,143	$1,143	$1,166	$1,284	$1,488	$1,482	$1,478	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$170	$170	$110	$0	$0	$40	$0	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$7,239	$7,239	$6,863	$6,207	$6,636	$6,092	$6,221	[p]
Book Value of Long-Term Debt	$7,801	$7,801	$7,404	$7,264	$7,386	$6,786	$6,735	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$8,368	$8,368	$8,347	$8,025	$7,861	$7,013	$5,962	
Carrying Amount	$7,642	$7,642	$7,229	$7,073	$7,174	$6,567	$6,348	
Adjustment to Book Value of Long-Term Debt	$726	$726	$1,118	$952	$687	$446	($386)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$8,527	$8,527	$8,522	$8,216	$8,073	$7,232	$6,349	[s] = [q] + [r].
Market Value of Debt	$8,527	$8,527	$8,522	$8,216	$8,073	$7,232	$6,349	[t] = [s].
MARKET VALUE OF FIRM	$16,325	$15,457	$14,627	$13,148	$12,182	$10,449	$8,347	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	47.77%	44.83%	41.74%	37.51%	33.73%	28.50%	21.02%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	2.29%	2.91%	[w] = [i] / [u].
Debt - Market Value Ratio	52.23%	55.17%	58.26%	62.49%	66.27%	69.21%	76.07%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel F: Cleco Corp

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$1,586	$1,586	$1,499	$1,420	$1,317	$1,115	$1,060	[a]
Shares Outstanding (in millions) - Common	60	60	60	60	61	60	60	[b]
Price per Share - Common	$51	$45.65	$38.56	$34	$28	$24	$18	[c]
Market Value of Common Equity	$3,104	$2,760	$2,328	$2,065	$1,676	$1,421	$1,090	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$3,104	$2,760	$2,328	$2,065	$1,676	$1,421	$1,090	[f]= [d] + [e]
Market to Book Value of Common Equity	1.96	1.74	1.55	1.45	1.27	1.27	1.03	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$1	$1	$1	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$1	$1	$1	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$474	$474	$447	$457	$609	$494	$466	[j]
Current Liabilities	$243	$243	$295	$321	$478	$242	$361	[k]
Current Portion of Long-Term Debt	$17	$17	$91	$24	$12	$11	$64	[l]
Net Working Capital	$247	$247	$244	$160	$143	$264	$169	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$0	$150	$0	$0	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,316	$1,316	$1,257	$1,337	$1,400	$1,320	$1,107	[p]
Book Value of Long-Term Debt	$1,333	$1,333	$1,348	$1,361	$1,412	$1,332	$1,170	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,420	$1,420	$1,580	$1,543	$1,462	$1,353	$1,110	
Carrying Amount	$1,331	$1,331	$1,345	$1,355	$1,404	$1,320	$1,173	
Adjustment to Book Value of Long-Term Debt	$89	$89	$234	$188	$58	$34	($63)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,422	$1,422	$1,583	$1,550	$1,470	$1,366	$1,108	[s] = [q] + [r].
Market Value of Debt	$1,422	$1,422	$1,583	$1,550	$1,470	$1,366	$1,108	[t] = [s].
MARKET VALUE OF FIRM	$4,525	$4,181	$3,910	$3,615	$3,147	$2,788	$2,198	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	68.59%	66.00%	59.52%	57.13%	53.25%	50.98%	49.57%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	0.03%	0.04%	0.05%	[w] = [i] / [u].
Debt - Market Value Ratio	31.41%	34.00%	40.48%	42.87%	46.72%	48.98%	50.39%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel G: CenterPoint Energy Inc

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$4,329	$4,329	$4,301	$4,222	$3,198	$2,639	$2,022	[a]
Shares Outstanding (in millions) - Common	429	429	428	426	425	391	346	[b]
Price per Share - Common	$24	$22.54	$18.51	$18	$14	$12	$10	[c]
Market Value of Common Equity	$10,226	$9,669	$7,922	$7,603	$5,867	$4,701	$3,322	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$10,226	$9,669	$7,922	$7,603	$5,867	$4,701	$3,322	[f]= [d] + [e]
Market to Book Value of Common Equity	2.36	2.23	1.84	1.80	1.83	1.78	1.64	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$2,658	$2,658	$2,874	$2,337	$2,582	$2,904	$3,035	[j]
Current Liabilities	$3,019	$3,019	$3,575	$2,593	$2,620	$3,038	$2,848	[k]
Current Portion of Long-Term Debt	$497	$497	$1,400	$484	$428	$903	$333	[l]
Net Working Capital	$136	$136	$699	$228	$390	$769	$520	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$43	$43	$38	$62	$53	$55	$153	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$7,817	$7,817	$8,357	$8,641	$9,001	$9,119	$10,181	[p]
Book Value of Long-Term Debt	$8,314	$8,314	$9,757	$9,125	$9,429	$10,022	$10,514	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$8,670	$8,670	$10,807	$10,049	$10,071	$10,413	$9,875	
Carrying Amount	$8,171	$8,171	$9,619	$8,994	$9,303	$9,900	$10,396	
Adjustment to Book Value of Long-Term Debt	$499	$499	$1,188	$1,055	$768	$513	($521)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$8,813	$8,813	$10,945	$10,180	$10,197	$10,535	$9,993	[s] = [q] + [r].
Market Value of Debt	$8,813	$8,813	$10,945	$10,180	$10,197	$10,535	$9,993	[t] = [s].
MARKET VALUE OF FIRM	$19,039	$18,482	$18,867	$17,783	$16,064	$15,236	$13,315	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	53.71%	52.32%	41.99%	42.75%	36.52%	30.86%	24.95%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	46.29%	47.68%	58.01%	57.25%	63.48%	69.14%	75.05%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel H: Dominion Resources Inc/VA

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$11,642	$11,642	$10,568	$11,446	$11,997	$11,185	$10,077	[a]
Shares Outstanding (in millions) - Common	581	581	576	570	581	599	583	[b]
Price per Share - Common	$69	$63.05	$48.89	$47	$37	$33	$27	[c]
Market Value of Common Equity	$40,110	$36,632	$28,161	$26,812	$21,546	$19,565	$16,024	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$40,110	$36,632	$28,161	$26,812	$21,546	$19,565	$16,024	[f]= [d] + [e]
Market to Book Value of Common Equity	3.45	3.15	2.66	2.34	1.80	1.75	1.59	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$257	$257	$257	$257	$257	$257	$257	[h]
Market Value of Preferred Equity	$257	$257	$257	$257	$257	$257	$257	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$5,940	$5,940	$5,140	$5,430	$5,400	$6,817	$7,661	[j]
Current Liabilities	$6,994	$6,994	$7,763	$6,962	$5,773	$6,833	$7,794	[k]
Current Portion of Long-Term Debt	$1,519	$1,519	$2,223	$1,479	$497	$1,137	$444	[l]
Net Working Capital	$465	$465	($400)	($53)	$124	$1,121	$311	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,927	$1,927	$2,412	$1,814	$1,386	$1,295	$2,030	[n]
Adjusted Short-Term Debt	$0	$0	$400	$53	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$19,330	$19,330	$16,851	$17,394	$15,758	$15,481	$14,956	[p]
Book Value of Long-Term Debt	$20,849	$20,849	$19,474	$18,926	$16,255	$16,618	$15,400	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$19,887	$19,887	$19,898	$18,936	$16,112	$15,970	$14,260	
Carrying Amount	$18,396	$18,396	$16,841	$16,264	$14,520	$14,867	$14,334	
Adjustment to Book Value of Long-Term Debt	$1,491	$1,491	$3,057	$2,672	$1,592	$1,103	($74)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$22,340	$22,340	$22,531	$21,598	$17,847	$17,721	$15,326	[s] = [q] + [r].
Market Value of Debt	$22,340	$22,340	$22,531	$21,598	$17,847	$17,721	$15,326	[t] = [s].
MARKET VALUE OF FIRM	$62,707	$59,229	$50,949	$48,667	$39,650	$37,543	$31,607	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	63.96%	61.85%	55.27%	55.09%	54.34%	52.11%	50.70%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.41%	0.43%	0.50%	0.53%	0.65%	0.68%	0.81%	[w] = [i] / [u].
Debt - Market Value Ratio	35.63%	37.72%	44.22%	44.38%	45.01%	47.20%	48.49%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel I: DTE Energy Co

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$7,921	$7,921	$7,373	$7,009	$6,722	$6,278	$5,995	[a]
Shares Outstanding (in millions) - Common	177	177	172	169	169	165	163	[b]
Price per Share - Common	$76	$65.40	$57.73	$49	$39	$36	$27	[c]
Market Value of Common Equity	$13,372	$11,582	$9,950	$8,217	$6,685	$6,005	$4,439	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$13,372	$11,582	$9,950	$8,217	$6,685	$6,005	$4,439	[f]= [d] + [e]
Market to Book Value of Common Equity	1.69	1.46	1.35	1.17	0.99	0.96	0.74	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$2,806	$2,806	$2,915	$3,196	$3,167	$2,877	$3,328	[j]
Current Liabilities	$3,189	$3,189	$2,768	$2,628	$2,749	$2,645	$3,013	[k]
Current Portion of Long-Term Debt	$898	$898	$817	$526	$925	$671	$362	[l]
Net Working Capital	$515	$515	$964	$1,094	$1,343	$903	$677	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$131	$131	$240	$419	$150	$327	$744	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$7,214	$7,214	$7,014	$7,187	$7,089	$7,370	$7,741	[p]
Book Value of Long-Term Debt	$8,112	$8,112	$7,831	$7,713	$8,014	$8,041	$8,103	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$8,475	$8,475	$8,893	$8,800	$8,500	$8,300	$7,700	
Carrying Amount	$8,094	$8,094	$7,813	$7,700	$8,000	$8,000	$8,000	
Adjustment to Book Value of Long-Term Debt	$381	$381	$1,080	$1,100	$500	$300	($300)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$8,493	$8,493	$8,911	$8,813	$8,514	$8,341	$7,803	[s] = [q] + [r].
Market Value of Debt	$8,493	$8,493	$8,911	$8,813	$8,514	$8,341	$7,803	[t] = [s].
MARKET VALUE OF FIRM	$21,865	$20,075	$18,861	$17,030	$15,199	$14,346	$12,242	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	61.16%	57.69%	52.76%	48.25%	43.98%	41.86%	36.26%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	38.84%	42.31%	47.24%	51.75%	56.02%	58.14%	63.74%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel J: Consolidated Edison Inc

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$12,245	$12,245	$11,869	$11,436	$11,061	$10,249	$9,698	[a]
Shares Outstanding (in millions) - Common	293	293	293	293	292	281	274	[b]
Price per Share - Common	$55	$53.62	$52.57	$55	$43	$37	$30	[c]
Market Value of Common Equity	$15,998	$15,703	$15,396	$16,001	$12,408	$10,444	$8,168	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$15,998	$15,703	$15,396	$16,001	$12,408	$10,444	$8,168	[f]= [d] + [e]
Market to Book Value of Common Equity	1.31	1.28	1.30	1.40	1.12	1.02	0.84	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$213	$213	$213	$213	[h]
Market Value of Preferred Equity	$0	$0	$0	$213	$213	$213	$213	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,891	$3,891	$3,451	$3,638	$3,669	$3,214	$3,319	[j]
Current Liabilities	$4,730	$4,730	$3,945	$2,987	$2,530	$2,940	$3,205	[k]
Current Portion of Long-Term Debt	$485	$485	$706	$530	$5	$731	$482	[l]
Net Working Capital	($354)	($354)	$212	$1,181	$1,144	$1,005	$596	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,451	$1,451	$539	$0	$0	$0	$363	[n]
Adjusted Short-Term Debt	$354	$354	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$10,490	$10,490	$10,064	$10,145	$10,678	$9,868	$9,249	[p]
Book Value of Long-Term Debt	$11,329	$11,329	$10,770	$10,675	$10,683	$10,599	$9,731	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$12,082	$12,082	$12,935	$12,744	$11,795	$11,009	$9,249	
Carrying Amount	$10,974	$10,974	$10,768	$10,673	$10,676	$10,585	$9,249	
Adjustment to Book Value of Long-Term Debt	$1,108	$1,108	$2,167	$2,071	$1,119	$424	$0	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$12,437	$12,437	$12,937	$12,746	$11,802	$11,023	$9,731	[s] = [q] + [r].
Market Value of Debt	$12,437	$12,437	$12,937	$12,746	$11,802	$11,023	$9,731	[t] = [s].
MARKET VALUE OF FIRM	$28,435	$28,140	$28,333	$28,960	$24,423	$21,680	$18,112	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	56.26%	55.80%	54.34%	55.25%	50.80%	48.17%	45.10%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	0.74%	0.87%	0.98%	1.18%	[w] = [i] / [u].
Debt - Market Value Ratio	43.74%	44.20%	45.66%	44.01%	48.32%	50.84%	53.73%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel K: El Paso Electric Co

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$944	$944	$825	$760	$810	$723	$694	[a]
Shares Outstanding (in millions) - Common	40	40	40	40	65	65	45	[b]
Price per Share - Common	$37	$34.36	$30.48	$32	$26	$19	$16	[c]
Market Value of Common Equity	$1,481	$1,379	$1,220	$1,266	$1,668	$1,208	$729	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$1,481	$1,379	$1,220	$1,266	$1,668	$1,208	$729	[f]= [d] + [e]
Market to Book Value of Common Equity	1.57	1.46	1.48	1.67	2.06	1.67	1.05	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$179	$179	$246	$155	$230	$250	$286	[j]
Current Liabilities	$138	$138	$152	$185	$131	$172	$145	[k]
Current Portion of Long-Term Debt	$0	$0	$0	$33	$5	$42	$24	[l]
Net Working Capital	$41	$41	$94	$3	$104	$119	$164	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$14	$14	$22	$33	$0	$0	$0	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,000	$1,000	$1,000	$816	$850	$805	$810	[p]
Book Value of Long-Term Debt	$1,000	$1,000	$1,000	$850	$854	$847	$833	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,059	$1,059	$1,182	$1,057	$883	$850	$685	
Carrying Amount	$1,014	$1,014	$1,022	$883	$854	$847	$833	
Adjustment to Book Value of Long-Term Debt	$45	$45	$160	$174	$28	$3	($148)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,044	$1,044	$1,160	$1,024	$883	$850	$685	[s] = [q] + [r].
Market Value of Debt	$1,044	$1,044	$1,160	$1,024	$883	$850	$685	[t] = [s].
MARKET VALUE OF FIRM								
	$2,526	$2,424	$2,380	$2,290	$2,551	$2,058	$1,414	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	58.65%	56.91%	51.27%	55.28%	65.39%	58.69%	51.53%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	41.35%	43.09%	48.73%	44.72%	34.61%	41.31%	48.47%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel L: Edison International

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$9,938	$9,938	$9,432	$10,055	$10,583	$9,841	$9,517	[a]
Shares Outstanding (in millions) - Common	326	326	326	326	326	326	326	[b]
Price per Share - Common	$55	$45.39	$43.29	$37	$35	$31	$26	[c]
Market Value of Common Equity	$17,829	$14,789	$14,105	$12,168	$11,324	$10,059	$8,535	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$17,829	$14,789	$14,105	$12,168	$11,324	$10,059	$8,535	[f]= [d] + [e]
Market to Book Value of Common Equity	1.79	1.49	1.50	1.21	1.07	1.02	0.90	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$1,753	$1,753	$1,759	$1,029	$907	$907	$907	[h]
Market Value of Preferred Equity	$1,753	$1,753	$1,759	$1,029	$907	$907	$907	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,312	$3,312	$2,672	$4,484	$4,422	$4,430	$7,353	[j]
Current Liabilities	$4,881	$4,881	$3,744	$4,348	$3,952	$3,787	$6,697	[k]
Current Portion of Long-Term Debt	$601	$601	$0	$0	$48	$377	$174	[l]
Net Working Capital	($968)	($968)	($1,072)	$136	$518	$1,020	$830	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$209	$209	$175	$429	$115	$309	$2,367	[n]
Adjusted Short-Term Debt	$209	$209	$175	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$9,825	$9,825	$9,231	$8,834	$12,371	$10,437	$10,950	[p]
Book Value of Long-Term Debt	$10,635	$10,635	$9,406	$8,834	$12,419	$10,814	$11,124	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$11,084	$11,084	$10,944	$14,264	$12,360	$10,452	$10,637	
Carrying Amount	$10,426	$10,426	$9,231	$13,746	$12,419	$10,814	$10,950	
Adjustment to Book Value of Long-Term Debt	$658	$658	$1,713	$518	($59)	($362)	($313)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$11,293	$11,293	$11,119	$9,352	$12,360	$10,452	$10,811	[s] = [q] + [r].
Market Value of Debt	$11,293	$11,293	$11,119	$9,352	$12,360	$10,452	$10,811	[t] = [s].
MARKET VALUE OF FIRM	$30,875	$27,835	$26,983	$22,549	$24,591	$21,418	$20,253	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	57.75%	53.13%	52.27%	53.96%	46.05%	46.97%	42.14%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	5.68%	6.30%	6.52%	4.56%	3.69%	4.23%	4.48%	[w] = [i] / [u].
Debt - Market Value Ratio	36.58%	40.57%	41.21%	41.47%	50.26%	48.80%	53.38%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel M: Entergy Corp

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$9,632	$9,632	$9,197	$8,961	$8,496	$8,613	$7,967	[a]
Shares Outstanding (in millions) - Common	178	178	178	176	179	189	189	[b]
Price per Share - Common	$74	$60.60	$59.35	$64	$60	$67	$63	[c]
Market Value of Common Equity	$13,277	$10,809	$10,553	$11,245	$10,656	$12,649	$11,971	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$13,277	$10,809	$10,553	$11,245	$10,656	$12,649	$11,971	[f]= [d] + [e]
Market to Book Value of Common Equity	1.38	1.12	1.15	1.25	1.25	1.47	1.50	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$305	$305	$281	$281	$311	$311	$311	[h]
Market Value of Preferred Equity	$305	$305	$281	$281	$311	$311	$311	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,930	$3,930	$3,683	$3,623	$4,339	$4,534	$5,160	[j]
Current Liabilities	$4,061	$4,061	$4,106	$4,951	$2,776	$3,194	$3,766	[k]
Current Portion of Long-Term Debt	$459	$459	$722	$2,196	$303	$924	$707	[l]
Net Working Capital	$329	$329	$299	$868	$1,866	$2,265	$2,101	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,047	$1,047	$796	$108	$154	$30	$55	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$12,171	$12,171	$11,955	$10,082	$11,359	$11,060	$11,517	[p]
Book Value of Long-Term Debt	$12,631	$12,631	$12,677	$12,278	$11,662	$11,984	$12,224	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$12,440	$12,440	$12,849	$12,176	$10,989	$10,728	$10,118	
Carrying Amount	$12,596	$12,596	$12,639	$12,236	$11,617	$11,418	$11,719	
Adjustment to Book Value of Long-Term Debt	($156)	($156)	$210	($60)	($628)	($690)	($1,601)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$12,474	$12,474	$12,888	$12,218	$11,034	$11,295	$10,623	[s] = [q] + [r].
Market Value of Debt	$12,474	$12,474	$12,888	$12,218	$11,034	$11,295	$10,623	[t] = [s].
MARKET VALUE OF FIRM	$26,056	$23,589	$23,721	$23,744	$22,001	$24,255	$22,905	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	50.96%	45.83%	44.49%	47.36%	48.44%	52.15%	52.26%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	1.17%	1.29%	1.18%	1.18%	1.41%	1.28%	1.36%	[w] = [i] / [u].
Debt - Market Value Ratio	47.87%	52.88%	54.33%	51.46%	50.15%	46.57%	46.38%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel N: Great Plains Energy Inc

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$3,474	$3,474	$3,340	$2,960	$2,886	$2,793	$2,551	[a]
Shares Outstanding (in millions) - Common	154	154	154	136	136	135	119	[b]
Price per Share - Common	$25	$23.68	$19.21	$19	$17	$16	$15	[c]
Market Value of Common Equity	$3,877	$3,644	$2,950	$2,636	$2,288	$2,191	$1,775	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$3,877	$3,644	$2,950	$2,636	$2,288	$2,191	$1,775	[f]= [d] + [e]
Market to Book Value of Common Equity	1.12	1.05	0.88	0.89	0.79	0.78	0.70	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$39	$39	$39	$39	$39	$39	$39	[h]
Market Value of Preferred Equity	$39	$39	$39	$39	$39	$39	$39	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$767	$767	$724	$619	$612	$613	$604	[j]
Current Liabilities	$770	$770	$1,450	$1,635	$1,339	$958	$1,337	[k]
Current Portion of Long-Term Debt	$1	$1	$263	$801	$486	$1	$71	[l]
Net Working Capital	($2)	($2)	($463)	($214)	($242)	($345)	($663)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$292	$292	$716	$384	$368	$439	$584	[n]
Adjusted Short-Term Debt	$2	$2	$463	$214	$242	$345	$584	[o] = See Sources and Notes.
Long-Term Debt	$3,516	$3,516	$2,757	$2,742	$2,943	$3,213	$2,557	[p]
Book Value of Long-Term Debt	$3,519	$3,519	$3,483	$3,758	$3,670	$3,559	$3,212	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$3,700	$3,700	$3,500	$3,900	$3,700	$3,400	$2,200	
Carrying Amount	$3,500	$3,500	$3,000	$3,500	$3,400	$3,200	$2,600	
Adjustment to Book Value of Long-Term Debt	$200	$200	$500	$400	$300	$200	($400)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$3,719	$3,719	$3,983	$4,158	$3,970	$3,759	$2,812	[s] = [q] + [r].
Market Value of Debt	$3,719	$3,719	$3,983	$4,158	$3,970	$3,759	$2,812	[t] = [s].
MARKET VALUE OF FIRM	$7,635	$7,402	$6,971	$6,833	$6,297	$5,989	$4,626	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	50.78%	49.23%	42.31%	38.58%	36.33%	36.58%	38.38%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.51%	0.53%	0.56%	0.57%	0.62%	0.65%	0.84%	[w] = [i] / [u].
Debt - Market Value Ratio	48.70%	50.24%	57.13%	60.85%	63.05%	62.77%	60.78%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel O: Hawaiian Electric Industries Inc

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$1,727	$1,727	$1,594	$1,529	$1,484	$1,442	$1,389	[a]
Shares Outstanding (in millions) - Common	101	101	98	96	95	93	91	[b]
Price per Share - Common	$24	$25.04	$23.56	$23	$19	$17	$16	[c]
Market Value of Common Equity	$2,413	$2,535	$2,307	$2,225	$1,796	$1,549	$1,488	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$2,413	$2,535	$2,307	$2,225	$1,796	$1,549	$1,488	[f]= [d] + [e]
Market to Book Value of Common Equity	1.40	1.47	1.45	1.46	1.21	1.07	1.07	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$34	$34	$34	$34	$34	$34	$34	[h]
Market Value of Preferred Equity	$34	$34	$34	$34	$34	$34	$34	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,188	$1,188	$1,350	$1,337	$1,276	$1,178	$1,142	[j]
Current Liabilities	$4,962	$4,962	$4,748	$4,613	$4,468	$4,585	$5,045	[k]
Current Portion of Long-Term Debt	$0	$0	$0	$0	$0	$0	$0	[l]
Net Working Capital	($3,773)	($3,773)	($3,398)	($3,277)	($3,192)	($3,407)	($3,903)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$350	$350	$280	$302	$262	$340	$681	[n]
Adjusted Short-Term Debt	$350	$350	$280	$302	$262	$340	$681	[o] = See Sources and Notes.
Long-Term Debt	$1,493	$1,493	$1,423	$1,340	$1,365	$1,365	$1,212	[p]
Book Value of Long-Term Debt	$1,843	$1,843	$1,702	$1,642	$1,627	$1,704	$1,892	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,508	$1,508	$1,481	$1,400	$1,346	$1,336	$1,212	
Carrying Amount	$1,493	$1,493	$1,423	$1,340	$1,365	$1,365	$1,212	
Adjustment to Book Value of Long-Term Debt	$15	$15	$58	$60	($19)	($29)	$0	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,858	$1,858	$1,761	$1,702	$1,608	$1,676	$1,892	[s] = [q] + [r].
Market Value of Debt	$1,858	$1,858	$1,761	$1,702	$1,608	$1,676	$1,892	[t] = [s].
MARKET VALUE OF FIRM	$4,306	$4,428	$4,102	$3,961	$3,439	$3,259	$3,415	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	56.04%	57.26%	56.25%	56.16%	52.24%	47.52%	43.58%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.80%	0.77%	0.84%	0.87%	1.00%	1.05%	1.00%	[w] = [i] / [u].
Debt - Market Value Ratio	43.16%	41.97%	42.92%	42.97%	46.76%	51.43%	55.42%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel P: IDACORP Inc

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$1,851	$1,851	$1,742	$1,658	$1,532	$1,397	$1,302	[a]
Shares Outstanding (in millions) - Common	50	50	50	50	49	48	47	[b]
Price per Share - Common	$54	$51.41	$41.55	$38	$33	$27	$24	[c]
Market Value of Common Equity	$2,724	$2,582	$2,084	$1,914	$1,654	$1,316	$1,126	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$2,724	$2,582	$2,084	$1,914	$1,654	$1,316	$1,126	[f]= [d] + [e]
Market to Book Value of Common Equity	1.47	1.40	1.20	1.15	1.08	0.94	0.86	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$477	$477	$367	$311	$464	$310	$266	[j]
Current Liabilities	$250	$250	$351	$368	$449	$218	$396	[k]
Current Portion of Long-Term Debt	$1	$1	$71	$101	$123	$9	$87	[l]
Net Working Capital	$227	$227	$87	$44	$138	$102	($43)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$55	$55	$70	$54	$67	$54	$151	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$43	[o] = See Sources and Notes.
Long-Term Debt	$1,615	$1,615	$1,467	$1,388	$1,488	$1,410	$1,183	[p]
Book Value of Long-Term Debt	$1,616	$1,616	$1,538	$1,489	$1,611	$1,419	$1,313	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,600	$1,600	$1,819	$1,738	$1,623	$1,407	$1,200	
Carrying Amount	$1,616	$1,616	$1,538	$1,492	$1,614	$1,422	$1,277	
Adjustment to Book Value of Long-Term Debt	($16)	($16)	$282	$246	$9	($15)	($77)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,600	$1,600	$1,819	$1,735	$1,619	$1,404	$1,235	[s] = [q] + [r].
Market Value of Debt	$1,600	$1,600	$1,819	$1,735	$1,619	$1,404	$1,235	[t] = [s].
MARKET VALUE OF FIRM								
	$4,325	$4,183	$3,903	$3,649	$3,274	$2,720	$2,362	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	63.00%	61.74%	53.39%	52.46%	50.53%	48.40%	47.68%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	37.00%	38.26%	46.61%	47.54%	49.47%	51.60%	52.32%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
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Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel Q: Alliant Energy Corp

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$3,281	$3,281	$3,135	$3,013	$2,894	$2,773	$2,824	[a]
Shares Outstanding (in millions) - Common	111	111	111	111	111	111	110	[b]
Price per Share - Common	$57	$50.45	$41.96	$39	$32	$25	$23	[c]
Market Value of Common Equity	$6,370	$5,597	$4,658	$4,323	$3,556	$2,815	$2,502	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$6,370	$5,597	$4,658	$4,323	$3,556	$2,815	$2,502	[f]= [d] + [e]
Market to Book Value of Common Equity	1.94	1.71	1.49	1.43	1.23	1.02	0.89	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$200	$200	$205	$205	$244	$244	$244	[h]
Market Value of Preferred Equity	$200	$200	$205	$205	$244	$244	$244	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,011	$1,011	$994	$871	$1,093	$1,390	$1,446	[j]
Current Liabilities	$1,433	$1,433	$1,020	$855	$867	$1,077	$1,038	[k]
Current Portion of Long-Term Debt	$359	$359	$2	$1	$1	$102	$136	[l]
Net Working Capital	($64)	($64)	($24)	$17	$227	$415	$544	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$279	$279	$218	$103	$47	$190	$86	[n]
Adjusted Short-Term Debt	$64	$64	$24	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$2,978	$2,978	$3,137	$2,703	$2,703	$2,405	$1,748	[p]
Book Value of Long-Term Debt	$3,400	$3,400	$3,162	$2,705	$2,705	$2,506	$1,885	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$3,712	$3,712	$3,861	$3,325	$2,959	$2,676	$2,107	
Carrying Amount	$3,336	$3,336	$3,138	$2,705	$2,705	$2,506	$1,885	
Adjustment to Book Value of Long-Term Debt	$376	$376	$722	$621	$254	$170	$222	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$3,776	$3,776	$3,885	$3,325	$2,959	$2,676	$2,107	[s] = [q] + [r].
Market Value of Debt	$3,776	$3,776	$3,885	$3,325	$2,959	$2,676	$2,107	[t] = [s].
MARKET VALUE OF FIRM	$10,346	$9,573	$8,747	$7,853	$6,758	$5,734	$4,853	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	61.57%	58.47%	53.25%	55.05%	52.61%	49.09%	51.56%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	1.93%	2.09%	2.34%	2.61%	3.61%	4.25%	5.02%	[w] = [i] / [u].
Debt - Market Value Ratio	36.50%	39.44%	44.41%	42.34%	43.78%	46.66%	43.41%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
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Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel R: MGE Energy Inc

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$618	$618	$579	$551	$525	$502	$478	[a]
Shares Outstanding (in millions) - Common	35	35	35	35	35	35	34	[b]
Price per Share - Common	$37	$36.92	$32.77	$28	$26	$21	$17	[c]
Market Value of Common Equity	$1,282	$1,280	$1,136	$982	$887	$713	$599	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$1,282	$1,280	$1,136	$982	$887	$713	$599	[f]= [d] + [e]
Market to Book Value of Common Equity	2.08	2.07	1.96	1.78	1.69	1.42	1.25	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$221	$221	$223	$189	$162	$165	$194	[j]
Current Liabilities	$97	$97	$76	$63	$81	$127	$205	[k]
Current Portion of Long-Term Debt	$4	$4	$3	$3	$2	$2	$0	[l]
Net Working Capital	$128	$128	$150	$129	$83	$39	($11)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$0	$0	$23	$65	$125	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$11	[o] = See Sources and Notes.
Long-Term Debt	$399	$399	$358	$361	$334	$321	$272	[p]
Book Value of Long-Term Debt	$404	$404	$362	$364	$336	$322	$284	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$432	$432	$427	$433	$356	$340	$261	
Carrying Amount	$404	$404	$362	$364	$337	$324	$274	
Adjustment to Book Value of Long-Term Debt	$28	$28	$66	$68	$19	$16	($12)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$432	$432	$427	$432	$355	$339	$272	[s] = [q] + [r].
Market Value of Debt	$432	$432	$427	$432	$355	$339	$272	[t] = [s].
MARKET VALUE OF FIRM	$1,713	$1,712	$1,563	$1,414	$1,242	$1,051	$870	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	74.80%	74.78%	72.68%	69.47%	71.39%	67.80%	68.80%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	25.20%	25.22%	27.32%	30.53%	28.61%	32.20%	31.20%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel S: NextEra Energy Inc

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$18,040	$18,040	$16,068	$14,943	$14,392	$12,882	$11,581	[a]
Shares Outstanding (in millions) - Common	435	435	424	416	421	414	409	[b]
Price per Share - Common	$96	$82.57	$66.35	$54	$46	$46	$40	[c]
Market Value of Common Equity	$41,766	$35,919	$28,131	$22,497	$19,216	$19,021	$16,243	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$41,766	$35,919	$28,131	$22,497	$19,216	$19,021	$16,243	[f]= [d] + [e]
Market to Book Value of Common Equity	2.32	1.99	1.75	1.51	1.34	1.48	1.40	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$5,842	$5,842	$5,237	$4,872	$5,258	$4,337	$5,392	[j]
Current Liabilities	$9,189	$9,189	$8,879	$6,719	$6,904	$6,449	$7,689	[k]
Current Portion of Long-Term Debt	$3,766	$3,766	$2,771	$808	$1,920	$569	$1,388	[l]
Net Working Capital	$419	$419	($871)	($1,039)	$274	($1,543)	($909)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$691	$691	$1,411	$1,349	$889	$2,020	$1,865	[n]
Adjusted Short-Term Debt	$0	$0	$871	$1,039	$0	$1,543	$909	[o] = See Sources and Notes.
Long-Term Debt	$23,969	$23,969	$23,177	$20,810	$18,013	$16,300	$13,833	[p]
Book Value of Long-Term Debt	$27,735	$27,735	$26,819	$22,657	$19,933	$18,412	$16,130	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$28,612	$28,612	$28,874	$23,699	$20,756	$17,256	$15,152	
Carrying Amount	$27,728	$27,728	$26,647	$21,614	$19,929	$16,869	$15,221	
Adjustment to Book Value of Long-Term Debt	$884	$884	$2,227	$2,085	$827	$387	($69)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$28,619	$28,619	$29,046	$24,742	$20,760	$18,799	$16,061	[s] = [q] + [r].
Market Value of Debt	$28,619	$28,619	$29,046	$24,742	$20,760	$18,799	$16,061	[t] = [s].
MARKET VALUE OF FIRM	$70,385	$64,538	$57,177	$47,239	$39,976	$37,820	$32,304	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	59.34%	55.66%	49.20%	47.62%	48.07%	50.29%	50.28%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	40.66%	44.34%	50.80%	52.38%	51.93%	49.71%	49.72%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel T: OGE Energy Corp

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$3,037	$3,037	$2,767	$2,563	$2,290	$2,041	$1,897	[a]
Shares Outstanding (in millions) - Common	199	199	198	196	195	194	187	[b]
Price per Share - Common	$36	$33.31	$27.05	$26	$21	$16	$10	[c]
Market Value of Common Equity	$7,149	$6,611	$5,344	$5,016	$4,023	$3,113	$1,933	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$7,149	$6,611	$5,344	$5,016	$4,023	$3,113	$1,933	[f]= [d] + [e]
Market to Book Value of Common Equity	2.35	2.18	1.93	1.96	1.76	1.53	1.02	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$695	$695	$794	$653	$632	$826	$745	[j]
Current Liabilities	$1,094	$1,094	$1,276	$999	$815	$1,276	$888	[k]
Current Portion of Long-Term Debt	$100	$100	$0	$0	$0	$289	$0	[l]
Net Working Capital	($299)	($299)	($482)	($346)	($182)	($160)	($144)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$440	$440	$431	$277	$145	$175	$298	[n]
Adjusted Short-Term Debt	$299	$299	$431	$277	$145	$160	$144	[o] = See Sources and Notes.
Long-Term Debt	$2,300	$2,300	$2,849	$2,737	$2,363	$2,089	$2,162	[p]
Book Value of Long-Term Debt	$2,699	$2,699	$3,280	$3,014	$2,508	$2,539	$2,306	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,653	$2,653	$3,397	$3,276	$2,579	$2,477	$2,112	
Carrying Amount	$2,400	$2,400	$2,849	$2,737	$2,363	$2,378	$2,160	
Adjustment to Book Value of Long-Term Debt	$253	$253	$548	$539	$216	$99	($48)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,952	$2,952	$3,828	$3,553	$2,724	$2,637	$2,258	[s] = [q] + [r].
Market Value of Debt	$2,952	$2,952	$3,828	$3,553	$2,724	$2,637	$2,258	[t] = [s].
MARKET VALUE OF FIRM	$10,101	$9,563	$9,172	$8,569	$6,747	$5,750	$4,191	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	70.78%	69.13%	58.27%	58.54%	59.62%	54.13%	46.12%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	29.22%	30.87%	41.73%	41.46%	40.38%	45.87%	53.88%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel U: Otter Tail Corp

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$535	$535	$522	$571	$632	$673	$677	[a]
Shares Outstanding (in millions) - Common	36	36	36	36	36	36	35	[b]
Price per Share - Common	$28	$28.53	$23.45	$19	$19	$19	$17	[c]
Market Value of Common Equity	$1,020	$1,035	$848	$695	$693	$692	$601	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$1,020	$1,035	$848	$695	$693	$692	$601	[f]= [d] + [e]
Market to Book Value of Common Equity	1.91	1.93	1.62	1.22	1.10	1.03	0.89	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$16	$16	$16	$16	$16	[h]
Market Value of Preferred Equity	$0	$0	$16	$16	$16	$16	$16	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$251	$251	$324	$475	$514	$350	$393	[j]
Current Liabilities	$233	$233	$173	$192	$285	$207	$305	[k]
Current Portion of Long-Term Debt	$0	$0	$0	$0	$0	$59	$4	[l]
Net Working Capital	$18	$18	$151	$282	$229	$202	$92	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$51	$51	#N/A N/A	#N/A N/A	$79	$8	$135	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$390	$390	$422	$472	$434	$436	$340	[p]
Book Value of Long-Term Debt	$390	$390	$422	$472	$434	$495	$343	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$428	$428	$491	$525	$475	$458	$308	
Carrying Amount	$390	$390	$422	$472	$435	$436	$340	
Adjustment to Book Value of Long-Term Debt	$38	$38	$70	$53	$39	$22	($31)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$428	$428	$491	$525	$473	$517	$312	[s] = [q] + [r].
Market Value of Debt	$428	$428	$491	$525	$473	$517	$312	[t] = [s].
MARKET VALUE OF FIRM	$1,448	$1,463	$1,355	$1,236	$1,182	$1,224	$929	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	70.46%	70.75%	62.59%	56.25%	58.64%	56.50%	64.74%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	1.14%	1.25%	1.31%	1.27%	1.67%	[w] = [i] / [u].
Debt - Market Value Ratio	29.54%	29.25%	36.27%	42.49%	40.05%	42.23%	33.59%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel V: PG&E Corp

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$14,342	$14,342	$13,074	$12,101	$11,282	$10,333	$9,377	[a]
Shares Outstanding (in millions) - Common	457	457	431	412	395	371	336	[b]
Price per Share - Common	$45	$39.75	$38.34	$36	$41	$37	$30	[c]
Market Value of Common Equity	$20,342	$18,154	$16,514	$14,884	$16,341	$13,852	$10,154	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$20,342	$18,154	$16,514	$14,884	$16,341	$13,852	$10,154	[f]= [d] + [e]
Market to Book Value of Common Equity	1.42	1.27	1.26	1.23	1.45	1.34	1.08	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$252	$252	$252	$252	$252	$252	$252	[h]
Market Value of Preferred Equity	$252	$252	$252	$252	$252	$252	$252	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$5,977	$5,977	$5,121	$6,480	$5,542	$5,657	$6,403	[j]
Current Liabilities	$7,493	$7,493	$6,256	$7,749	$7,185	$6,813	$7,626	[k]
Current Portion of Long-Term Debt	$889	$889	$400	$473	$1,213	$728	$970	[l]
Net Working Capital	($627)	($627)	($735)	($796)	($430)	($428)	($253)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,174	$1,174	$492	$1,647	$853	$833	$287	[n]
Adjusted Short-Term Debt	$627	$627	$492	$796	$430	$428	$253	[o] = See Sources and Notes.
Long-Term Debt	$12,717	$12,717	$12,517	$11,766	$11,329	$11,208	$10,534	[p]
Book Value of Long-Term Debt	$14,233	$14,233	$13,409	$13,035	$12,972	$12,364	$11,757	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$0	$0	$0	$0	$0	$0	$0	
Carrying Amount	$0	$0	$0	$0	$0	$0	$0	
Adjustment to Book Value of Long-Term Debt	$0	$0	$0	$0	$0	$0	$0	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$14,233	$14,233	$13,409	$13,035	$12,972	$12,364	$11,757	[s] = [q] + [r].
Market Value of Debt	$14,233	$14,233	$13,409	$13,035	$12,972	$12,364	$11,757	[t] = [s].
MARKET VALUE OF FIRM	$34,827	$32,639	$30,175	$28,171	$29,565	$26,468	$22,163	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	58.41%	55.62%	54.73%	52.84%	55.27%	52.33%	45.81%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.72%	0.77%	0.84%	0.89%	0.85%	0.95%	1.14%	[w] = [i] / [u].
Debt - Market Value Ratio	40.87%	43.61%	44.44%	46.27%	43.88%	46.71%	53.05%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel W: Public Service Enterprise Group Inc

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$11,608	$11,608	$10,780	$10,270	$9,633	$8,788	$7,771	[a]
Shares Outstanding (in millions) - Common	506	506	506	506	506	506	506	[b]
Price per Share - Common	$38	$31.31	$28.55	$29	$27	$28	$23	[c]
Market Value of Common Equity	$19,046	$15,840	$14,441	$14,451	$13,658	$13,916	$11,388	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$19,046	$15,840	$14,441	$14,451	$13,658	$13,916	$11,388	[f]= [d] + [e]
Market to Book Value of Common Equity	1.64	1.36	1.34	1.41	1.42	1.58	1.47	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$80	$80	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$80	$80	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,614	$3,614	$3,869	$3,911	$5,051	$4,290	$3,999	[j]
Current Liabilities	$3,063	$3,063	$3,777	$2,957	$3,485	$3,360	$3,410	[k]
Current Portion of Long-Term Debt	$781	$781	$1,252	$633	$1,121	$521	$1,033	[l]
Net Working Capital	$1,332	$1,332	$1,344	$1,587	$2,687	$1,451	$1,622	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$60	$60	$263	#N/A N/A	$64	$530	$19	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$7,862	$7,862	$6,687	$7,461	$7,819	$7,645	$8,005	[p]
Book Value of Long-Term Debt	$8,643	$8,643	$7,939	$8,094	$8,940	$8,166	$9,038	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$9,061	$9,061	$9,324	$9,283	$9,836	$8,973	$9,159	
Carrying Amount	$8,643	$8,643	$7,939	$8,094	$8,940	$8,166	$9,038	
Adjustment to Book Value of Long-Term Debt	$418	$418	$1,385	$1,189	$896	$807	$121	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$9,061	$9,061	$9,324	$9,283	$9,836	$8,973	$9,159	[s] = [q] + [r].
Market Value of Debt	$9,061	$9,061	$9,324	$9,283	$9,836	$8,973	$9,159	[t] = [s].
MARKET VALUE OF FIRM	$28,107	$24,901	$23,765	$23,734	$23,494	$22,969	$20,627	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	67.76%	63.61%	60.77%	60.89%	58.13%	60.59%	55.21%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	0.35%	0.39%	[w] = [i] / [u].
Debt - Market Value Ratio	32.24%	36.39%	39.23%	39.11%	41.87%	39.07%	44.40%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel X: Pinnacle West Capital Corp

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$4,194	$4,194	$3,973	$3,822	$3,683	$3,316	$3,446	[a]
Shares Outstanding (in millions) - Common	110	110	110	109	109	101	101	[b]
Price per Share - Common	$55	$51.92	$48.46	$43	$36	$30	$23	[c]
Market Value of Common Equity	$6,054	$5,721	$5,319	$4,660	$3,897	$3,081	$2,361	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$6,054	$5,721	$5,319	$4,660	$3,897	$3,081	$2,361	[f]= [d] + [e]
Market to Book Value of Common Equity	1.44	1.36	1.34	1.22	1.06	0.93	0.69	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,044	$1,044	$1,006	$956	$1,025	$929	$882	[j]
Current Liabilities	$1,619	$1,619	$1,084	$1,343	$1,450	$1,109	$1,506	[k]
Current Portion of Long-Term Debt	$540	$540	$123	$477	$632	$303	$178	[l]
Net Working Capital	($35)	($35)	$45	$91	$207	$123	($446)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$153	$153	$92	$0	$17	$154	$670	[n]
Adjusted Short-Term Debt	$35	$35	$0	$0	$0	$0	$446	[o] = See Sources and Notes.
Long-Term Debt	$2,796	$2,796	$3,199	$3,019	$3,046	$3,497	$3,032	[p]
Book Value of Long-Term Debt	$3,372	$3,372	$3,322	$3,496	$3,678	$3,800	$3,655	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$3,579	$3,579	$3,875	$3,926	$3,913	$3,774	$2,818	
Carrying Amount	$3,337	$3,337	$3,322	$3,496	$3,678	$3,648	$3,209	
Adjustment to Book Value of Long-Term Debt	$242	$242	$553	$430	$235	$126	($391)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$3,614	$3,614	$3,875	$3,926	$3,913	$3,926	$3,264	[s] = [q] + [r].
Market Value of Debt	$3,614	$3,614	$3,875	$3,926	$3,913	$3,926	$3,264	[t] = [s].
MARKET VALUE OF FIRM	$9,667	$9,334	$9,193	$8,587	$7,809	$7,007	$5,625	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	62.62%	61.29%	57.85%	54.27%	49.90%	43.97%	41.97%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	37.38%	38.71%	42.15%	45.73%	50.10%	56.03%	58.03%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel Y: Portland General Electric Co

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$1,819	$1,819	$1,728	$1,663	$1,592	$1,542	$1,354	[a]
Shares Outstanding (in millions) - Common	78	78	76	75	75	75	63	[b]
Price per Share - Common	$33	$29.52	$25.92	$23	$19	$17	$14	[c]
Market Value of Common Equity	$2,568	$2,305	$1,959	$1,710	$1,451	$1,298	$903	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$2,568	$2,305	$1,959	$1,710	$1,451	$1,298	$903	[f]= [d] + [e]
Market to Book Value of Common Equity	1.41	1.27	1.13	1.03	0.91	0.84	0.67	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$591	$591	$622	$716	$661	$690	$820	[j]
Current Liabilities	$393	$393	$521	$614	$489	$620	$889	[k]
Current Portion of Long-Term Debt	$0	$0	$100	$100	$10	$186	$142	[l]
Net Working Capital	$198	$198	$201	$202	$182	$256	$73	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$0	$0	$17	$30	$19	$0	$203	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$1,916	$1,916	$1,536	$1,635	$1,798	$1,558	$1,164	[p]
Book Value of Long-Term Debt	$1,916	$1,916	$1,636	$1,735	$1,808	$1,744	$1,306	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$2,074	$2,074	$1,949	$2,091	$1,968	$1,818	$1,286	
Carrying Amount	$1,916	$1,916	$1,636	$1,735	$1,808	$1,744	$1,308	
Adjustment to Book Value of Long-Term Debt	$158	$158	$313	$356	$160	$74	($22)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$2,074	$2,074	$1,949	$2,091	$1,968	$1,818	$1,284	[s] = [q] + [r].
Market Value of Debt	$2,074	$2,074	$1,949	$2,091	$1,968	$1,818	$1,284	[t] = [s].
MARKET VALUE OF FIRM	$4,642	$4,379	$3,908	$3,801	$3,419	$3,116	$2,187	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	55.32%	52.64%	50.12%	44.98%	42.44%	41.65%	41.28%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	44.68%	47.36%	49.88%	55.02%	57.56%	58.35%	58.72%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel Z: SCANA Corp

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$4,664	$4,664	$4,154	$3,889	$3,702	$3,408	$3,045	[a]
Shares Outstanding (in millions) - Common	141	141	132	130	127	123	118	[b]
Price per Share - Common	$51	$46.40	$43.65	$40	$35	$31	$27	[c]
Market Value of Common Equity	$7,252	$6,542	$5,780	$5,173	$4,478	$3,830	$3,195	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$7,252	$6,542	$5,780	$5,173	$4,478	$3,830	$3,195	[f]= [d] + [e]
Market to Book Value of Common Equity	1.55	1.40	1.39	1.33	1.21	1.12	1.05	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$106	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$106	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,421	$1,421	$1,527	$1,491	$1,631	$1,521	$1,836	[j]
Current Liabilities	$1,442	$1,442	$1,811	$1,642	$1,867	$1,256	$1,155	[k]
Current Portion of Long-Term Debt	$54	$54	$172	$31	$337	$28	$144	[l]
Net Working Capital	$33	$33	($112)	($120)	$101	$293	$825	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$376	$376	$623	$653	$420	$335	$80	[n]
Adjusted Short-Term Debt	$0	$0	$112	$120	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$5,395	$5,395	$4,949	$4,622	$4,152	$4,483	$4,368	[p]
Book Value of Long-Term Debt	$5,449	$5,449	$5,233	$4,773	$4,489	$4,511	$4,512	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$5,916	$5,916	$6,115	$5,479	$4,841	$4,726	$4,592	
Carrying Amount	$5,449	$5,449	$5,121	$4,653	$4,488	$4,511	$4,506	
Adjustment to Book Value of Long-Term Debt	$467	$467	$994	$826	$352	$215	$86	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$5,916	$5,916	$6,227	$5,599	$4,841	$4,726	$4,598	[s] = [q] + [r].
Market Value of Debt	$5,916	$5,916	$6,227	$5,599	$4,841	$4,726	$4,598	[t] = [s].
MARKET VALUE OF FIRM	$13,168	$12,458	$12,007	$10,772	$9,320	$8,556	$7,899	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	55.07%	52.51%	48.14%	48.02%	48.05%	44.76%	40.45%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	1.34%	[w] = [i] / [u].
Debt - Market Value Ratio	44.93%	47.49%	51.86%	51.98%	51.95%	55.24%	58.21%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel AA: Southern Co/The

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$19,008	$19,008	$18,297	$17,578	$16,202	$14,878	$13,276	[a]
Shares Outstanding (in millions) - Common	887	887	868	866	843	820	778	[b]
Price per Share - Common	$43	$39.71	$40.32	$41	$33	$27	$28	[c]
Market Value of Common Equity	$38,447	$35,237	$35,002	$35,091	$27,433	$22,391	$21,662	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$38,447	$35,237	$35,002	$35,091	$27,433	$22,391	$21,662	[f]= [d] + [e]
Market to Book Value of Common Equity	2.02	1.85	1.91	2.00	1.69	1.50	1.63	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$1,131	$1,131	$1,082	$1,082	$1,082	$1,082	$1,082	[h]
Market Value of Preferred Equity	$1,131	$1,131	$1,082	$1,082	$1,082	$1,082	$1,082	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$5,599	$5,599	$6,162	$6,272	$5,883	$5,873	$5,358	[j]
Current Liabilities	$5,536	$5,536	$7,014	$6,577	$6,472	$5,584	$5,226	[k]
Current Portion of Long-Term Debt	$469	$469	$2,335	$1,717	$1,301	$1,113	$617	[l]
Net Working Capital	$532	$532	$1,483	$1,412	$712	$1,402	$749	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$1,482	$1,482	$825	$859	$1,297	$639	$953	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$21,344	$21,344	$19,274	$18,647	$18,154	$18,131	$16,816	[p]
Book Value of Long-Term Debt	$21,813	$21,813	$21,609	$20,364	$19,455	$19,244	$17,433	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$22,197	$22,197	$23,480	$22,144	$20,073	$19,567	$17,114	
Carrying Amount	$21,650	$21,650	$21,530	$20,272	$19,356	$19,145	$17,327	
Adjustment to Book Value of Long-Term Debt	$547	$547	$1,950	$1,872	$717	$422	($213)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$22,360	$22,360	$23,559	$22,236	$20,172	$19,666	$17,220	[s] = [q] + [r].
Market Value of Debt	$22,360	$22,360	$23,559	$22,236	$20,172	$19,666	$17,220	[t] = [s].
MARKET VALUE OF FIRM	$61,938	$58,728	$59,643	$58,409	$48,687	$43,139	$39,964	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	62.07%	60.00%	58.69%	60.08%	56.35%	51.90%	54.20%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	1.83%	1.93%	1.81%	1.85%	2.22%	2.51%	2.71%	[w] = [i] / [u].
Debt - Market Value Ratio	36.10%	38.07%	39.50%	38.07%	41.43%	45.59%	43.09%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
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Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel AB: Sempra Energy

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$11,008	$11,008	$10,282	$9,775	$9,027	$9,007	$7,969	[a]
Shares Outstanding (in millions) - Common	244	244	242	240	240	247	243	[b]
Price per Share - Common	$99	$87.22	$68.52	$50	$46	$48	$35	[c]
Market Value of Common Equity	$24,114	$21,283	$16,583	$11,880	$11,138	$11,905	$8,419	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$24,114	$21,283	$16,583	$11,880	$11,138	$11,905	$8,419	[f]= [d] + [e]
Market to Book Value of Common Equity	2.19	1.93	1.61	1.22	1.23	1.32	1.06	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$20	$20	$99	$99	$179	$179	$179	[h]
Market Value of Preferred Equity	$20	$20	$99	$99	$179	$179	$179	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,997	$3,997	$3,695	$2,332	$3,353	$2,295	$2,476	[j]
Current Liabilities	$4,369	$4,369	$4,258	$4,152	$3,786	$3,888	$3,612	[k]
Current Portion of Long-Term Debt	$1,147	$1,147	$725	$336	$349	$573	$410	[l]
Net Working Capital	$775	$775	$162	($1,484)	($84)	($1,020)	($726)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$545	$545	$546	$449	$158	$618	$503	[n]
Adjusted Short-Term Debt	$0	$0	$0	$449	$84	$618	$503	[o] = See Sources and Notes.
Long-Term Debt	$11,253	$11,253	$11,621	$10,078	$8,980	$7,460	$6,544	[p]
Book Value of Long-Term Debt	$12,400	$12,400	$12,346	$10,863	$9,413	$8,651	$7,457	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$12,676	$12,676	$13,243	$11,047	$8,883	$8,618	$7,013	
Carrying Amount	$12,022	$12,022	$11,873	$9,826	$8,330	$8,050	$6,962	
Adjustment to Book Value of Long-Term Debt	$654	$654	$1,370	$1,221	$553	$568	$51	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$13,054	$13,054	$13,716	$12,084	$9,966	$9,219	$7,508	[s] = [q] + [r].
Market Value of Debt	$13,054	$13,054	$13,716	$12,084	$9,966	$9,219	$7,508	[t] = [s].
MARKET VALUE OF FIRM	$37,188	$34,357	$30,398	$24,063	$21,283	$21,303	$16,106	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	64.84%	61.95%	54.55%	49.37%	52.33%	55.88%	52.27%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.05%	0.06%	0.33%	0.41%	0.84%	0.84%	1.11%	[w] = [i] / [u].
Debt - Market Value Ratio	35.10%	38.00%	45.12%	50.22%	46.83%	43.28%	46.61%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
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Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel AC: Integrys Energy Group Inc

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$3,261	$3,261	$3,026	$2,961	$2,906	$2,850	$3,100	[a]
Shares Outstanding (in millions) - Common	79	79	78	78	77	76	76	[b]
Price per Share - Common	$57	$52.76	$49.50	$46	$41	$34	$31	[c]
Market Value of Common Equity	$4,543	$4,191	$3,856	$3,622	$3,183	$2,546	$2,326	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$4,543	$4,191	$3,856	$3,622	$3,183	$2,546	$2,326	[f]= [d] + [e]
Market to Book Value of Common Equity	1.39	1.29	1.27	1.22	1.10	0.89	0.75	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$51	$51	$51	$51	$51	$51	$51	[h]
Market Value of Preferred Equity	$51	$51	$51	$51	$51	$51	$51	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,972	$1,972	$1,659	$1,828	$2,050	$3,512	$5,891	[j]
Current Liabilities	$1,622	$1,622	$1,813	$1,674	$1,658	$3,148	$5,714	[k]
Current Portion of Long-Term Debt	$100	$100	$314	$250	$477	$117	$155	[l]
Net Working Capital	$450	$450	$159	$405	$870	$481	$332	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$326	$326	$482	$303	$10	$222	$1,209	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$2,956	$2,956	$1,932	$1,845	$2,162	$2,395	$2,288	[p]
Book Value of Long-Term Debt	$3,056	$3,056	$2,245	$2,095	$2,639	$2,511	$2,443	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$3,032	$3,032	$2,426	$2,282	$2,688	$2,544	$2,276	
Carrying Amount	$3,056	$3,056	$2,245	$2,122	$2,639	$2,511	$2,443	
Adjustment to Book Value of Long-Term Debt	($25)	($25)	$181	$160	$49	$32	($167)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$3,032	$3,032	$2,426	$2,255	$2,688	$2,544	$2,276	[s] = [q] + [r].
Market Value of Debt	$3,032	$3,032	$2,426	$2,255	$2,688	$2,544	$2,276	[t] = [s].
MARKET VALUE OF FIRM	$7,626	$7,274	$6,333	$5,928	$5,922	$5,141	$4,653	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	59.58%	57.62%	60.89%	61.11%	53.75%	49.53%	49.99%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.67%	0.70%	0.81%	0.86%	0.86%	0.99%	1.10%	[w] = [i] / [u].
Debt - Market Value Ratio	39.75%	41.68%	38.31%	38.03%	45.38%	49.48%	48.92%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
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Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel AD: Vectren Corp

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$1,554	$1,554	$1,526	$1,466	$1,439	$1,397	$1,352	[a]
Shares Outstanding (in millions) - Common	82	82	82	82	82	81	81	[b]
Price per Share - Common	$39	$34.23	$27.92	$26	$22	$20	$19	[c]
Market Value of Common Equity	$3,224	$2,820	$2,295	$2,162	$1,773	$1,627	$1,546	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$3,224	$2,820	$2,295	$2,162	$1,773	$1,627	$1,546	[f]= [d] + [e]
Market to Book Value of Common Equity	2.07	1.81	1.50	1.48	1.23	1.16	1.14	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	$0	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$630	$630	$678	$610	$645	$582	$776	[j]
Current Liabilities	$511	$511	$794	$694	$821	$748	$1,120	[k]
Current Portion of Long-Term Debt	$30	$30	$106	$63	$281	$99	$80	[l]
Net Working Capital	$150	$150	($10)	($21)	$105	($67)	($264)	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$69	$69	$279	$227	$118	$214	$520	[n]
Adjusted Short-Term Debt	$0	$0	$10	$21	$0	$67	$264	[o] = See Sources and Notes.
Long-Term Debt	$1,777	$1,777	$1,553	$1,560	$1,435	$1,541	$1,248	[p]
Book Value of Long-Term Debt	$1,807	$1,807	$1,669	$1,643	$1,716	$1,706	$1,593	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$1,895	$1,895	$1,873	$1,804	$1,767	$1,720	$1,251	
Carrying Amount	$1,807	$1,807	$1,660	$1,622	$1,716	$1,643	$1,373	
Adjustment to Book Value of Long-Term Debt	$88	$88	$214	$182	$51	$78	($122)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$1,895	$1,895	$1,883	$1,825	$1,767	$1,784	$1,471	[s] = [q] + [r].
Market Value of Debt	$1,895	$1,895	$1,883	$1,825	$1,767	$1,784	$1,471	[t] = [s].
MARKET VALUE OF FIRM	$5,119	$4,716	$4,178	$3,987	$3,540	$3,411	$3,017	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	62.98%	59.81%	54.93%	54.22%	50.08%	47.70%	51.25%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	-	[w] = [i] / [u].
Debt - Market Value Ratio	37.02%	40.19%	45.07%	45.78%	49.92%	52.30%	48.75%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel AE: Wisconsin Energy Corp

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$4,233	$4,233	$4,135	$3,963	$3,802	$3,567	$3,337	[a]
Shares Outstanding (in millions) - Common	226	226	229	230	234	234	234	[b]
Price per Share - Common	$45	$40.41	$35.43	$31	$26	$21	$17	[c]
Market Value of Common Equity	$10,217	$9,131	$8,114	$7,199	$6,134	$4,929	$4,063	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$10,217	$9,131	$8,114	$7,199	$6,134	$4,929	$4,063	[f]= [d] + [e]
Market to Book Value of Common Equity	2.41	2.16	1.96	1.82	1.61	1.38	1.22	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$30	$30	$30	$30	$30	$30	$30	[h]
Market Value of Preferred Equity	$30	$30	$30	$30	$30	$30	$30	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$1,551	$1,551	$1,314	$1,426	$1,331	$1,529	$1,693	[j]
Current Liabilities	$1,496	$1,496	$1,443	$1,365	$1,721	$1,894	$1,735	[k]
Current Portion of Long-Term Debt	$342	$342	$412	$33	$473	$296	$62	[l]
Net Working Capital	$397	$397	$283	$94	$83	($69)	$20	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$537	$537	$395	$670	$658	$825	$602	[n]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$69	$0	[o] = See Sources and Notes.
Long-Term Debt	$4,363	$4,363	$4,454	$4,614	$3,932	$3,876	$4,075	[p]
Book Value of Long-Term Debt	$4,705	$4,705	$4,866	$4,647	$4,405	$4,241	$4,137	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$4,912	$4,912	$5,447	$5,180	$4,578	$4,163	$3,712	
Carrying Amount	$4,627	$4,627	$4,773	$4,541	$4,288	$4,050	$4,009	
Adjustment to Book Value of Long-Term Debt	$285	$285	$674	$639	$290	$113	($298)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$4,991	$4,991	$5,540	$5,285	$4,695	$4,353	$3,839	[s] = [q] + [r].
Market Value of Debt	$4,991	$4,991	$5,540	$5,285	$4,695	$4,353	$3,839	[t] = [s].
MARKET VALUE OF FIRM	$15,238	$14,152	$13,685	$12,515	$10,860	$9,313	$7,932	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	67.05%	64.52%	59.29%	57.52%	56.48%	52.93%	51.22%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	0.20%	0.21%	0.22%	0.24%	0.28%	0.33%	0.38%	[w] = [i] / [u].
Debt - Market Value Ratio	32.75%	35.26%	40.48%	42.23%	43.24%	46.75%	48.40%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel AF: Westar Energy Inc

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$3,063	$3,063	$2,896	$2,769	$2,386	$2,249	$2,190	[a]
Shares Outstanding (in millions) - Common	128	128	127	126	112	109	108	[b]
Price per Share - Common	$35	$31.16	$26.87	$25	$22	$18	$15	[c]
Market Value of Common Equity	$4,516	$3,996	$3,400	$3,139	$2,417	$1,932	$1,582	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$4,516	$3,996	$3,400	$3,139	$2,417	$1,932	$1,582	[f]= [d] + [e]
Market to Book Value of Common Equity	1.47	1.30	1.17	1.13	1.01	0.86	0.72	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$21	$21	$21	$21	[h]
Market Value of Preferred Equity	$0	$0	$0	$21	$21	$21	$21	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$707	$707	$643	$634	$602	$629	$743	[j]
Current Liabilities	$955	$955	$846	$827	$783	$682	$872	[k]
Current Portion of Long-Term Debt	$277	$277	$26	$28	$30	$1	$146	[l]
Net Working Capital	$29	$29	($177)	($166)	($151)	($52)	$17	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$135	$135	$339	$286	$227	$243	$175	[n]
Adjusted Short-Term Debt	$0	$0	$177	$166	$151	$52	$0	[o] = See Sources and Notes.
Long-Term Debt	$3,164	$3,164	$3,042	$2,740	$2,777	$2,600	$2,310	[p]
Book Value of Long-Term Debt	$3,441	$3,441	$3,245	$2,934	$2,958	$2,653	$2,457	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$3,294	$3,294	$3,179	$2,624	$2,571	$2,528	$1,749	
Carrying Amount	$3,103	$3,103	$2,703	$2,373	$2,373	$2,374	$2,024	
Adjustment to Book Value of Long-Term Debt	$192	$192	$476	$251	$197	$155	($275)	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$3,633	$3,633	$3,721	$3,185	$3,155	$2,808	$2,182	[s] = [q] + [r].
Market Value of Debt	$3,633	$3,633	$3,721	$3,185	$3,155	$2,808	$2,182	[t] = [s].
MARKET VALUE OF FIRM	$8,149	$7,629	$7,121	$6,345	$5,593	$4,761	$3,785	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	55.42%	52.38%	47.74%	49.47%	43.21%	40.57%	41.80%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	0.34%	0.38%	0.45%	0.57%	[w] = [i] / [u].
Debt - Market Value Ratio	44.58%	47.62%	52.26%	50.19%	56.41%	58.98%	57.64%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-3

Market Value of the Electric Sample

Panel AG: Xcel Energy Inc

($MM)

	DCF Capital Structure	Year End, 2013	Year End, 2012	Year End, 2011	Year End, 2010	Year End, 2009	Year End, 2008	Notes
MARKET VALUE OF COMMON EQUITY								
Book Value, Common Shareholder's Equity	$9,566	$9,566	$8,874	$8,482	$8,084	$7,283	$6,964	[a]
Shares Outstanding (in millions) - Common	498	498	488	486	482	458	454	[b]
Price per Share - Common	$30	$27.50	$25.59	$24	$21	$18	$14	[c]
Market Value of Common Equity	$15,164	$13,692	$12,486	$11,874	$9,936	$8,187	$6,531	[d] = [b] x [c].
Market Value of GP Equity	$0	$0	$0	$0	$0	$0	$0	[e]
Total Market Value of Equity	$15,164	$13,692	$12,486	$11,874	$9,936	$8,187	$6,531	[f]= [d] + [e]
Market to Book Value of Common Equity	1.59	1.43	1.41	1.40	1.23	1.12	0.94	[g] = [f] / [a].
MARKET VALUE OF PREFERRED EQUITY								
Book Value of Preferred Equity	$0	$0	$0	$0	$105	$105	$105	[h]
Market Value of Preferred Equity	$0	$0	$0	$0	$105	$105	$105	[i] = [h].
MARKET VALUE OF DEBT								
Current Assets	$3,218	$3,218	$2,625	$2,983	$2,733	$2,977	$3,016	[j]
Current Liabilities	$3,654	$3,654	$2,937	$3,589	$2,537	$3,090	$3,046	[k]
Current Portion of Long-Term Debt	$281	$281	$258	$1,060	$55	$544	$559	[l]
Net Working Capital	($156)	($156)	($54)	$454	$252	$430	$528	[m] = [j] - ([k] - [l]).
Notes Payable (Short-Term Debt)	$759	$759	$602	$219	$466	$459	$455	[n]
Adjusted Short-Term Debt	$156	$156	$54	$0	$0	$0	$0	[o] = See Sources and Notes.
Long-Term Debt	$10,911	$10,911	$10,144	$8,849	$9,263	$7,889	$7,732	[p]
Book Value of Long-Term Debt	$11,347	$11,347	$10,456	$9,908	$9,319	$8,432	$8,290	[q] = [l] + [o] + [p].
Unadjusted Market Value of Long Term Debt	$11,879	$11,879	$12,208	$11,735	$10,225	$9,026	$8,562	
Carrying Amount	$11,192	$11,192	$10,402	$9,908	$9,319	$8,432	$8,290	
Adjustment to Book Value of Long-Term Debt	$687	$687	$1,806	$1,826	$906	$594	$272	[r] = See Sources and Notes.
Market Value of Long-Term Debt	$12,034	$12,034	$12,262	$11,735	$10,225	$9,026	$8,562	[s] = [q] + [r].
Market Value of Debt	$12,034	$12,034	$12,262	$11,735	$10,225	$9,026	$8,562	[t] = [s].
MARKET VALUE OF FIRM	$27,199	$25,727	$24,748	$23,609	$20,266	$17,319	$15,198	[u] = [f] + [i] + [t].
DEBT AND EQUITY TO MARKET VALUE RATIOS								
Common Equity - Market Value Ratio	55.75%	53.22%	50.45%	50.29%	49.03%	47.28%	42.97%	[v] = [f] / [u].
Preferred Equity - Market Value Ratio	-	-	-	-	0.52%	0.61%	0.69%	[w] = [i] / [u].
Debt - Market Value Ratio	44.25%	46.78%	49.55%	49.71%	50.45%	52.12%	56.34%	[x] = [t] / [u].

Sources and Notes:
Bloomberg as of June 3, 2014
Capital structure from Year End, 2013 calculated using respective balance sheet information and 15-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2013 balance sheet information and a 15-trading day average closing price ending on 6/3/2014.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[o] =
(1): 0 if [m] > 0.
(2): The absolute value of [m] if [m] < 0 and |[m]| < [n].
(3): [l] if [m] < 0 and |[m]| > [n].
[r]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2013 10-K.

Table No. MJV-4

Electric Sample

Capital Structure Summary

Company	DCF Capital Structure			5-Year Average Capital Structure		
	Common Equity - Value Ratio [1]	Preferred Equity - Value Ratio [2]	Debt - Value Ratio [3]	Common Equity - Value Ratio [4]	Preferred Equity - Value Ratio [5]	Debt - Value Ratio [6]
ALLETE Inc	0.64	0.00	0.36	0.59	0.00	0.41
Ameren Corp	0.59	0.00	0.41	0.47	0.00	0.53
American Electric Power Co Inc	0.56	0.00	0.44	0.47	0.00	0.53
Black Hills Corp	0.62	0.00	0.38	0.49	0.00	0.51
CMS Energy Corp	0.48	0.00	0.52	0.37	0.00	0.62
Cleco Corp	0.69	0.00	0.31	0.57	0.00	0.43
CenterPoint Energy Inc	0.54	0.00	0.46	0.41	0.00	0.59
Dominion Resources Inc/VA	0.64	0.00	0.36	0.56	0.01	0.44
DTE Energy Co	0.61	0.00	0.39	0.49	0.00	0.51
Consolidated Edison Inc	0.56	0.00	0.44	0.53	0.01	0.47
El Paso Electric Co	0.59	0.00	0.41	0.58	0.00	0.42
Edison International	0.58	0.06	0.37	0.50	0.05	0.44
Entergy Corp	0.51	0.01	0.48	0.48	0.01	0.51
Great Plains Energy Inc	0.51	0.01	0.49	0.41	0.01	0.59
Hawaiian Electric Industries Inc	0.56	0.01	0.43	0.54	0.01	0.45
IDACORP Inc	0.63	0.00	0.37	0.53	0.00	0.47
Alliant Energy Corp	0.62	0.02	0.36	0.54	0.03	0.43
MGE Energy Inc	0.75	0.00	0.25	0.71	0.00	0.29
NextEra Energy Inc	0.59	0.00	0.41	0.50	0.00	0.50
OGE Energy Corp	0.71	0.00	0.29	0.60	0.00	0.40
Otter Tail Corp	0.70	0.00	0.30	0.61	0.01	0.38
PG&E Corp	0.58	0.01	0.41	0.54	0.01	0.45
Public Service Enterprise Group Inc	0.68	0.00	0.32	0.61	0.00	0.39
Pinnacle West Capital Corp	0.63	0.00	0.37	0.53	0.00	0.47
Portland General Electric Co	0.55	0.00	0.45	0.46	0.00	0.54
SCANA Corp	0.55	0.00	0.45	0.48	0.00	0.52
Southern Co/The	0.62	0.02	0.36	0.57	0.02	0.41
Sempra Energy	0.65	0.00	0.35	0.55	0.00	0.45
Integrys Energy Group Inc	0.60	0.01	0.40	0.57	0.01	0.43
Vectren Corp	0.63	0.00	0.37	0.53	0.00	0.47
Wisconsin Energy Corp	0.67	0.00	0.33	0.58	0.00	0.42
Westar Energy Inc	0.55	0.00	0.45	0.47	0.00	0.53
Xcel Energy Inc	0.56	0.00	0.44	0.50	0.00	0.50
Average	0.60	0.00	0.39	0.53	0.01	0.47

Sources and Notes:
[1], [4]:Workpaper #1 to Table No. MJV-4.
[2], [5]:Workpaper #2 to Table No. MJV-4.
[3], [6]:Workpaper #3 to Table No. MJV-4.
Values in this table may not add up exactly to 1.0 because of rounding.

Workpaper #1 to Table No. MJV-4

Electric Sample

Calculation of the Average Common Equity - Market Value Ratio

Company	DCF Capital Structure [1]	Year End, 2013 [2]	2012 [3]	2011 [4]	2010 [5]	2009 [6]	5-Year Average [7]
ALLETE Inc	0.64	0.64	0.57	0.59	0.59	0.57	0.59
Ameren Corp	0.59	0.57	0.50	0.48	0.42	0.39	0.47
American Electric Power Co Inc	0.56	0.53	0.48	0.46	0.44	0.42	0.47
Black Hills Corp	0.62	0.60	0.51	0.46	0.43	0.44	0.49
CMS Energy Corp	0.48	0.45	0.42	0.38	0.34	0.28	0.37
Cleco Corp	0.69	0.66	0.60	0.57	0.53	0.51	0.57
CenterPoint Energy Inc	0.54	0.52	0.42	0.43	0.37	0.31	0.41
Dominion Resources Inc/VA	0.64	0.62	0.55	0.55	0.54	0.52	0.56
DTE Energy Co	0.61	0.58	0.53	0.48	0.44	0.42	0.49
Consolidated Edison Inc	0.56	0.56	0.54	0.55	0.51	0.48	0.53
El Paso Electric Co	0.59	0.57	0.51	0.55	0.65	0.59	0.58
Edison International	0.58	0.53	0.52	0.54	0.46	0.47	0.50
Entergy Corp	0.51	0.46	0.44	0.47	0.48	0.52	0.48
Great Plains Energy Inc	0.51	0.49	0.42	0.39	0.36	0.37	0.41
Hawaiian Electric Industries Inc	0.56	0.57	0.56	0.56	0.52	0.48	0.54
IDACORP Inc	0.63	0.62	0.53	0.52	0.51	0.48	0.53
Alliant Energy Corp	0.62	0.58	0.53	0.55	0.53	0.49	0.54
MGE Energy Inc	0.75	0.75	0.73	0.69	0.71	0.68	0.71
NextEra Energy Inc	0.59	0.56	0.49	0.48	0.48	0.50	0.50
OGE Energy Corp	0.71	0.69	0.58	0.59	0.60	0.54	0.60
Otter Tail Corp	0.70	0.71	0.63	0.56	0.59	0.57	0.61
PG&E Corp	0.58	0.56	0.55	0.53	0.55	0.52	0.54
Public Service Enterprise Group Inc	0.68	0.64	0.61	0.61	0.58	0.61	0.61
Pinnacle West Capital Corp	0.63	0.61	0.58	0.54	0.50	0.44	0.53
Portland General Electric Co	0.55	0.53	0.50	0.45	0.42	0.42	0.46
SCANA Corp	0.55	0.53	0.48	0.48	0.48	0.45	0.48
Southern Co/The	0.62	0.60	0.59	0.60	0.56	0.52	0.57
Sempra Energy	0.65	0.62	0.55	0.49	0.52	0.56	0.55
Integrys Energy Group Inc	0.60	0.58	0.61	0.61	0.54	0.50	0.57
Vectren Corp	0.63	0.60	0.55	0.54	0.50	0.48	0.53
Wisconsin Energy Corp	0.67	0.65	0.59	0.58	0.56	0.53	0.58
Westar Energy Inc	0.55	0.52	0.48	0.49	0.43	0.41	0.47
Xcel Energy Inc	0.56	0.53	0.50	0.50	0.49	0.47	0.50

Sources and Notes:
[1] - [6]: Table No. MJV-3; Panels A - AG, [v].
[7]: Average of [2] - [6].

Workpaper #2 to Table No. MJV-4

Electric Sample

Calculation of the Average Preferred Equity - Market Value Ratio

Company	DCF Capital Structure [1]	Year End, 2013 [2]	2012 [3]	2011 [4]	2010 [5]	2009 [6]	5-Year Average
ALLETE Inc	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ameren Corp	0.00	0.00	0.00	0.00	0.00	0.00	0.00
American Electric Power Co Inc	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Black Hills Corp	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CMS Energy Corp	0.00	0.00	0.00	0.00	0.00	0.02	0.00
Cleco Corp	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CenterPoint Energy Inc	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dominion Resources Inc/VA	0.00	0.00	0.01	0.01	0.01	0.01	0.01
DTE Energy Co	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Consolidated Edison Inc	0.00	0.00	0.00	0.01	0.01	0.01	0.01
El Paso Electric Co	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Edison International	0.06	0.06	0.07	0.05	0.04	0.04	0.05
Entergy Corp	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Great Plains Energy Inc	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Hawaiian Electric Industries Inc	0.01	0.01	0.01	0.01	0.01	0.01	0.01
IDACORP Inc	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Alliant Energy Corp	0.02	0.02	0.02	0.03	0.04	0.04	0.03
MGE Energy Inc	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NextEra Energy Inc	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OGE Energy Corp	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Otter Tail Corp	0.00	0.00	0.01	0.01	0.01	0.01	0.01
PG&E Corp	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Public Service Enterprise Group Inc	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pinnacle West Capital Corp	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Portland General Electric Co	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SCANA Corp	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Southern Co/The	0.02	0.02	0.02	0.02	0.02	0.03	0.02
Sempra Energy	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Integrys Energy Group Inc	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Vectren Corp	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wisconsin Energy Corp	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Westar Energy Inc	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Xcel Energy Inc	0.00	0.00	0.00	0.00	0.01	0.01	0.00

Sources and Notes:
[1] - [6]: Table No. MJV-3; Panels A - AG, [w].
[7]: Average of [2] - [6].

Workpaper #3 to Table No. MJV-4

Electric Sample

Calculation of the Average Debt - Market Value Ratio

Company	DCF Capital Structure [1]	Year End, 2013 [2]	2012 [3]	2011 [4]	2010 [5]	2009 [6]	5-Year Average [7]
ALLETE Inc	0.36	0.36	0.43	0.41	0.41	0.43	0.41
Ameren Corp	0.41	0.43	0.50	0.52	0.58	0.61	0.53
American Electric Power Co Inc	0.44	0.47	0.52	0.54	0.56	0.57	0.53
Black Hills Corp	0.38	0.40	0.49	0.54	0.57	0.56	0.51
CMS Energy Corp	0.52	0.55	0.58	0.62	0.66	0.69	0.62
Cleco Corp	0.31	0.34	0.40	0.43	0.47	0.49	0.43
CenterPoint Energy Inc	0.46	0.48	0.58	0.57	0.63	0.69	0.59
Dominion Resources Inc/VA	0.36	0.38	0.44	0.44	0.45	0.47	0.44
DTE Energy Co	0.39	0.42	0.47	0.52	0.56	0.58	0.51
Consolidated Edison Inc	0.44	0.44	0.46	0.44	0.48	0.51	0.47
El Paso Electric Co	0.41	0.43	0.49	0.45	0.35	0.41	0.42
Edison International	0.37	0.41	0.41	0.41	0.50	0.49	0.44
Entergy Corp	0.48	0.53	0.54	0.51	0.50	0.47	0.51
Great Plains Energy Inc	0.49	0.50	0.57	0.61	0.63	0.63	0.59
Hawaiian Electric Industries Inc	0.43	0.42	0.43	0.43	0.47	0.51	0.45
IDACORP Inc	0.37	0.38	0.47	0.48	0.49	0.52	0.47
Alliant Energy Corp	0.36	0.39	0.44	0.42	0.44	0.47	0.43
MGE Energy Inc	0.25	0.25	0.27	0.31	0.29	0.32	0.29
NextEra Energy Inc	0.41	0.44	0.51	0.52	0.52	0.50	0.50
OGE Energy Corp	0.29	0.31	0.42	0.41	0.40	0.46	0.40
Otter Tail Corp	0.30	0.29	0.36	0.42	0.40	0.42	0.38
PG&E Corp	0.41	0.44	0.44	0.46	0.44	0.47	0.45
Public Service Enterprise Group Inc	0.32	0.36	0.39	0.39	0.42	0.39	0.39
Pinnacle West Capital Corp	0.37	0.39	0.42	0.46	0.50	0.56	0.47
Portland General Electric Co	0.45	0.47	0.50	0.55	0.58	0.58	0.54
SCANA Corp	0.45	0.47	0.52	0.52	0.52	0.55	0.52
Southern Co/The	0.36	0.38	0.40	0.38	0.41	0.46	0.41
Sempra Energy	0.35	0.38	0.45	0.50	0.47	0.43	0.45
Integrys Energy Group Inc	0.40	0.42	0.38	0.38	0.45	0.49	0.43
Vectren Corp	0.37	0.40	0.45	0.46	0.50	0.52	0.47
Wisconsin Energy Corp	0.33	0.35	0.40	0.42	0.43	0.47	0.42
Westar Energy Inc	0.45	0.48	0.52	0.50	0.56	0.59	0.53
Xcel Energy Inc	0.44	0.47	0.50	0.50	0.50	0.52	0.50

Sources and Notes:
[1] - [6]: Table No. MJV-3; Panels A - AG, [x].
[7]: Average of [2] - [6].

Table No. MJV-5

Electric Sample

Estimated Growth Rates

Company	Bloomberg Estimate		Value Line			Combined BEst and Value Line Growth Rate
	BEst Long-Term Growth Rate	Number of Estimates	EPS Year 2014 Estimate	EPS Year 2017-2019 Estimate	Annualized Growth Rate	
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE Inc	6.0%	1	$2.85	$3.75	7.6%	6.8%
Ameren Corp	7.3%	3	$2.35	$3.00	6.7%	7.2%
American Electric Power Co Inc	5.7%	5	$3.30	$4.00	5.3%	5.6%
Black Hills Corp	7.0%	1	$2.65	$3.25	5.6%	6.3%
CMS Energy Corp	5.7%	4	$1.75	$2.25	6.9%	5.9%
Cleco Corp	7.0%	1	$2.75	$3.50	6.6%	6.8%
CenterPoint Energy Inc	5.0%	3	$1.15	$1.50	7.3%	5.6%
Dominion Resources Inc/VA	6.1%	3	$3.45	$4.00	4.0%	5.6%
DTE Energy Co	5.5%	5	$4.50	$5.25	4.2%	5.3%
Consolidated Edison Inc	3.8%	4	$3.70	$4.00	2.1%	3.5%
El Paso Electric Co	5.3%	2	$2.35	$2.75	4.3%	4.9%
Edison International	3.7%	8	$3.40	$4.50	7.8%	4.1%
Entergy Corp	0.1%	4	$4.80	$5.75	4.9%	1.1%
Great Plains Energy Inc	5.0%	4	$1.65	$2.00	5.3%	5.1%
Hawaiian Electric Industries Inc	3.4%	2	$1.60	$2.00	6.1%	4.3%
IDACORP Inc	4.0%	1	$3.50	$3.65	1.1%	2.6%
Alliant Energy Corp	5.0%	1	$3.45	$4.00	4.0%	4.5%
MGE Energy Inc	4.0%	1	$2.30	$3.10	8.3%	6.1%
NextEra Energy Inc	6.5%	4	$5.25	$6.50	5.9%	6.3%
OGE Energy Corp	5.0%	2	$2.00	$2.50	6.1%	5.4%
Otter Tail Corp	6.0%	1	$1.60	$2.20	8.9%	7.4%
PG&E Corp	5.8%	4	$2.20	$3.00	8.6%	6.3%
Public Service Enterprise Group Inc	5.2%	5	$2.50	$2.75	2.6%	4.8%
Pinnacle West Capital Corp	4.5%	5	$3.70	$4.25	3.8%	4.4%
Portland General Electric Co	6.8%	2	$2.05	$2.50	5.4%	6.3%
SCANA Corp	5.0%	1	$3.55	$4.25	4.9%	5.0%
Southern Co/The	3.9%	5	$2.80	$3.25	4.1%	4.0%
Sempra Energy	6.9%	6	$4.45	$6.25	9.5%	7.3%
Integrys Energy Group Inc	5.0%	1	$3.70	$4.50	5.4%	5.2%
Vectren Corp	4.5%	2	$2.25	$2.90	7.0%	5.3%
Wisconsin Energy Corp	4.7%	3	$2.60	$3.25	6.1%	5.1%
Westar Energy Inc	4.1%	3	$2.35	$2.75	4.3%	4.2%
Xcel Energy Inc	5.0%	3	$2.00	$2.50	6.1%	5.3%

Sources and Notes:

[1] - [2]: Bloomberg as of June 3, 2014. IDACORP, MGE Energy Inc, and Otter Tail Corp are from Thomson Reuters as of the same date.

[3] - [4]: From Valueline Investment Analyzer as of June 3, 2014..

[5]: ([4] / [3]) ^ (1/3.75) - 1.

[6]: ([1] x [2] + [5]) / ([2] + 1).

Table No. MJV-6

DCF Cost of Equity of the Electric Sample

Panel A: Simple DCF Method (Quarterly)

Company	Stock Price [1]	Most Recent Dividend [2]	Quarterly Dividend Yield [3]	Combined BEst and Value Line Long-Term Growth Rate [4]	Quarterly Growth Rate [5]	DCF Cost of Equity [6]
ALLETE Inc	$49.27	$0.49	0.99%	6.8%	1.7%	11.1%
Ameren Corp	$38.92	$0.40	1.03%	7.2%	1.7%	11.6%
American Electric Power Co Inc	$52.30	$0.50	0.96%	5.6%	1.4%	9.7%
Black Hills Corp	$56.67	$0.39	0.69%	6.3%	1.5%	9.3%
CMS Energy Corp	$29.30	$0.27	0.92%	5.9%	1.4%	9.9%
Cleco Corp	$51.34	$0.40	0.78%	6.8%	1.7%	10.2%
CenterPoint Energy Inc	$23.84	$0.24	1.00%	5.6%	1.4%	9.8%
Dominion Resources Inc/VA	$69.04	$0.60	0.87%	5.6%	1.4%	9.3%
DTE Energy Co	$75.51	$0.66	0.87%	5.3%	1.3%	9.0%
Consolidated Edison Inc	$54.63	$0.63	1.15%	3.5%	0.9%	8.3%
El Paso Electric Co	$36.90	$0.27	0.72%	4.9%	1.2%	8.0%
Edison International	$54.72	$0.36	0.65%	4.1%	1.0%	6.9%
Entergy Corp	$74.44	$0.83	1.12%	1.1%	0.3%	5.7%
Great Plains Energy Inc	$25.20	$0.23	0.91%	5.1%	1.2%	9.0%
Hawaiian Electric Industries Inc	$23.83	$0.31	1.30%	4.3%	1.1%	9.8%
IDACORP Inc	$54.24	$0.43	0.79%	2.6%	0.6%	5.9%
Alliant Energy Corp	$57.42	$0.51	0.89%	4.5%	1.1%	8.3%
MGE Energy Inc	$36.97	$0.27	0.73%	6.1%	1.5%	9.3%
NextEra Energy Inc	$96.01	$0.73	0.76%	6.3%	1.5%	9.6%
OGE Energy Corp	$36.02	$0.23	0.62%	5.4%	1.3%	8.0%
Otter Tail Corp	$28.13	$0.30	1.08%	7.4%	1.8%	12.1%
PG&E Corp	$44.54	$0.46	1.02%	6.3%	1.5%	10.7%
Public Service Enterprise Group Inc	$37.65	$0.37	0.98%	4.8%	1.2%	8.9%
Pinnacle West Capital Corp	$54.94	$0.57	1.03%	4.4%	1.1%	8.7%
Portland General Electric Co	$32.89	$0.28	0.84%	6.3%	1.5%	9.9%
SCANA Corp	$51.43	$0.53	1.02%	5.0%	1.2%	9.3%
Southern Co/The	$43.33	$0.53	1.21%	4.0%	1.0%	9.1%
Sempra Energy	$98.83	$0.66	0.67%	7.3%	1.8%	10.2%
Integrys Energy Group Inc	$57.19	$0.68	1.19%	5.2%	1.3%	10.3%
Vectren Corp	$39.12	$0.36	0.92%	5.3%	1.3%	9.3%
Wisconsin Energy Corp	$45.22	$0.39	0.86%	5.1%	1.2%	8.8%
Westar Energy Inc	$35.21	$0.35	0.99%	4.2%	1.0%	8.4%
Xcel Energy Inc	$30.45	$0.30	0.99%	5.3%	1.3%	9.5%

Sources and Notes:
[1]: Workpaper #1 to Table No. MJV-6.
[2]: Workpaper #2 to Table No. MJV-6.
[3]: [2] / [1].
[4]: Table No. MJV-5, [6].
[5]: {(1 + [4]) ^ (1/4)} - 1.
[6]: {(([2] / [1]) x (1 + [5]) + [5] + 1) ^ 4} - 1.

Table No. MJV-6

DCF Cost of Equity of the Electric Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company	Stock Price [1]	Most Recent Dividend [2]	Combined BEst and Value Line Long-Term Growth Rate [3]	Growth Rate: Year 6 [4]	Growth Rate: Year 7 [5]	Growth Rate: Year 8 [6]	Growth Rate: Year 9 [7]	Growth Rate: Year 10 [8]	GDP Long-Term Growth Rate [9]	DCF Cost of Equity [10]
ALLETE Inc	$49.27	$0.49	6.8%	6.4%	6.0%	5.6%	5.3%	4.9%	4.5%	9.4%
Ameren Corp	$38.92	$0.40	7.2%	6.7%	6.3%	5.8%	5.4%	4.9%	4.5%	9.6%
American Electric Power Co Inc	$52.30	$0.50	5.6%	5.4%	5.2%	5.0%	4.9%	4.7%	4.5%	8.8%
Black Hills Corp	$56.67	$0.39	6.3%	6.0%	5.7%	5.4%	5.1%	4.8%	4.5%	7.8%
CMS Energy Corp	$29.30	$0.27	5.9%	5.7%	5.5%	5.2%	5.0%	4.7%	4.5%	8.8%
Cleco Corp	$51.34	$0.40	6.8%	6.4%	6.0%	5.7%	5.3%	4.9%	4.5%	8.3%
CenterPoint Energy Inc	$23.84	$0.24	5.6%	5.4%	5.2%	5.0%	4.9%	4.7%	4.5%	9.0%
Dominion Resources Inc/VA	$69.04	$0.60	5.6%	5.4%	5.2%	5.0%	4.9%	4.7%	4.5%	8.4%
DTE Energy Co	$75.51	$0.66	5.3%	5.1%	5.0%	4.9%	4.8%	4.6%	4.5%	8.4%
Consolidated Edison Inc	$54.63	$0.63	3.5%	3.7%	3.8%	4.0%	4.2%	4.3%	4.5%	9.1%
El Paso Electric Co	$36.90	$0.27	4.9%	4.9%	4.8%	4.7%	4.6%	4.6%	4.5%	7.6%
Edison International	$54.72	$0.36	4.1%	4.2%	4.3%	4.3%	4.4%	4.4%	4.5%	7.2%
Entergy Corp	$74.44	$0.83	1.1%	1.7%	2.2%	2.8%	3.4%	3.9%	4.5%	8.3%
Great Plains Energy Inc	$25.20	$0.23	5.1%	5.0%	4.9%	4.8%	4.7%	4.6%	4.5%	8.5%
Hawaiian Electric Industries Inc	$23.83	$0.31	4.3%	4.3%	4.4%	4.4%	4.4%	4.5%	4.5%	10.0%
IDACORP Inc	$54.24	$0.43	2.6%	2.9%	3.2%	3.5%	3.9%	4.2%	4.5%	7.5%
Alliant Energy Corp	$57.42	$0.51	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	8.3%
MGE Energy Inc	$36.97	$0.27	6.1%	5.9%	5.6%	5.3%	5.0%	4.8%	4.5%	8.0%
NextEra Energy Inc	$96.01	$0.73	6.3%	6.0%	5.7%	5.4%	5.1%	4.8%	4.5%	8.1%
OGE Energy Corp	$36.02	$0.23	5.4%	5.2%	5.1%	4.9%	4.8%	4.6%	4.5%	7.3%
Otter Tail Corp	$28.13	$0.30	7.4%	6.9%	6.5%	6.0%	5.5%	5.0%	4.5%	10.0%
PG&E Corp	$44.54	$0.46	6.3%	6.0%	5.7%	5.4%	5.1%	4.8%	4.5%	9.4%
Public Service Enterprise Group Inc	$37.65	$0.37	4.8%	4.7%	4.7%	4.6%	4.6%	4.5%	4.5%	8.7%
Pinnacle West Capital Corp	$54.94	$0.57	4.4%	4.4%	4.4%	4.4%	4.5%	4.5%	4.5%	8.8%
Portland General Electric Co	$32.89	$0.28	6.3%	6.0%	5.7%	5.4%	5.1%	4.8%	4.5%	8.5%
SCANA Corp	$51.43	$0.53	5.0%	4.9%	4.8%	4.7%	4.7%	4.6%	4.5%	9.0%
Southern Co/The	$43.33	$0.53	4.0%	4.0%	4.1%	4.2%	4.3%	4.4%	4.5%	9.5%
Sempra Energy	$98.83	$0.66	7.3%	6.8%	6.3%	5.9%	5.4%	5.0%	4.5%	7.9%
Integrys Energy Group Inc	$57.19	$0.68	5.2%	5.1%	5.0%	4.8%	4.7%	4.6%	4.5%	9.8%
Vectren Corp	$39.12	$0.36	5.3%	5.2%	5.1%	4.9%	4.8%	4.6%	4.5%	8.6%
Wisconsin Energy Corp	$45.22	$0.39	5.1%	5.0%	4.9%	4.8%	4.7%	4.6%	4.5%	8.3%
Westar Energy Inc	$35.21	$0.35	4.2%	4.2%	4.3%	4.3%	4.4%	4.4%	4.5%	8.6%
Xcel Energy Inc	$30.45	$0.30	5.3%	5.2%	5.0%	4.9%	4.8%	4.6%	4.5%	8.9%

Sources and Notes:
[1]: Workpaper #1 to Table No. MJV-6.
[2]: Workpaper #2 to Table No. MJV-6.
[3]: Table No. MJV-5, [6].
[4]: [3] - {([3] - [9])/ 6}.
[5]: [4] - {([3] - [9])/ 6}.
[6]: [5] - {([3] - [9])/ 6}.
[7]: [6] - {([3] - [9])/ 6}.
[8]: [7] - {([3] - [9])/ 6}.
[9]: BlueChip Economic Indicators, March 2014 (U.S.) This number is assumed to be the perpetual growth rate.
[10]: Workpaper #3 to Table No. MJV-6.

Workpaper #1 to Table No. MJV-6

Electric Sample

Common Stock Prices from May 13, 2014 to June 3, 2014

Company	6/3/2014	6/2/2014	5/30/2014	5/29/2014	5/28/2014	5/27/2014	5/23/2014	5/22/2014	5/21/2014	5/20/2014	5/19/2014	5/16/2014	5/15/2014	5/14/2014	5/13/2014	Average
ALLETE Inc	$48.94	$49.32	$49.67	$49.51	$49.83	$50.12	$49.55	$49.26	$48.63	$48.60	$48.73	$49.36	$48.99	$49.30	$49.31	$49.27
Ameren Corp	$39.31	$39.04	$39.35	$38.91	$39.18	$38.91	$38.64	$38.73	$38.05	$38.43	$38.54	$39.22	$39.37	$39.27	$38.81	$38.92
American Electric Power Co Inc	$53.94	$53.48	$53.35	$52.79	$52.94	$52.70	$51.41	$51.49	$51.11	$50.96	$51.02	$52.70	$52.02	$52.36	$52.23	$52.30
Black Hills Corp	$57.39	$57.38	$57.67	$57.20	$57.41	$57.46	$56.73	$56.43	$55.95	$55.87	$56.04	$56.25	$56.01	$56.06	$56.15	$56.67
CMS Energy Corp	$29.78	$29.72	$29.75	$29.46	$29.53	$29.23	$29.30	$29.22	$28.87	$28.95	$28.88	$29.27	$29.23	$29.25	$29.11	$29.30
Cleco Corp	$51.56	$51.63	$52.03	$51.61	$51.88	$51.62	$51.42	$51.19	$50.58	$50.56	$50.61	$51.42	$51.01	$51.40	$51.54	$51.34
CenterPoint Energy Inc	$24.02	$24.08	$24.12	$24.06	$24.01	$23.96	$23.87	$24.03	$23.68	$23.64	$23.51	$23.88	$23.55	$23.70	$23.43	$23.84
Dominion Resources Inc/VA	$69.87	$69.60	$68.96	$68.52	$68.35	$68.82	$68.72	$69.22	$68.36	$68.32	$68.44	$69.72	$69.47	$69.96	$69.20	$69.04
DTE Energy Co	$76.22	$76.18	$76.12	$75.37	$75.36	$75.28	$74.88	$75.15	$74.36	$74.46	$74.70	$76.44	$75.85	$76.15	$76.14	$75.51
Consolidated Edison Inc	$55.00	$55.00	$55.01	$54.65	$54.52	$54.40	$54.13	$54.17	$53.86	$54.08	$54.30	$55.18	$54.96	$55.25	$54.87	$54.63
El Paso Electric Co	$37.37	$37.77	$38.11	$37.81	$37.79	$37.39	$36.82	$36.74	$36.21	$35.79	$35.89	$36.38	$36.07	$36.54	$36.75	$36.90
Edison International	$56.21	$55.67	$55.14	$54.59	$54.36	$54.09	$54.02	$54.36	$53.73	$54.03	$54.04	$55.28	$55.24	$55.10	$54.95	$54.72
Entergy Corp	$76.22	$75.77	$75.42	$75.53	$74.62	$74.11	$74.06	$74.04	$73.65	$73.49	$73.15	$74.52	$74.29	$74.27	$73.41	$74.44
Great Plains Energy Inc	$25.48	$25.39	$25.45	$25.29	$25.25	$25.13	$24.98	$25.01	$24.85	$24.90	$24.99	$25.45	$25.23	$25.35	$25.23	$25.20
Hawaiian Electric Industries Inc	$23.69	$23.84	$24.05	$24.07	$24.18	$23.93	$23.75	$23.74	$23.66	$23.68	$23.68	$23.99	$23.97	$23.63	$23.60	$23.83
IDACORP Inc	$54.24	$54.28	$54.83	$54.85	$55.03	$54.88	$54.00	$53.82	$53.36	$53.47	$53.81	$54.48	$54.15	$54.31	$54.03	$54.24
Alliant Energy Corp	$58.10	$58.21	$58.30	$57.75	$57.94	$57.39	$57.09	$56.98	$56.57	$56.47	$56.68	$57.54	$57.34	$57.57	$57.35	$57.42
MGE Energy Inc	$37.21	$37.21	$37.54	$37.65	$37.56	$37.77	$37.00	$36.67	$36.21	$36.34	$36.68	$36.80	$36.46	$36.59	$36.86	$36.97
NextEra Energy Inc	$97.16	$97.18	$97.36	$96.55	$96.64	$95.81	$95.74	$95.92	$95.56	$95.61	$93.99	$95.88	$95.55	$95.89	$95.36	$96.01
OGE Energy Corp	$36.55	$36.63	$36.73	$36.57	$36.56	$36.17	$35.87	$36.00	$35.35	$35.26	$35.22	$35.64	$35.73	$36.05	$35.91	$36.02
Otter Tail Corp	$28.48	$28.56	$28.58	$28.43	$28.32	$28.40	$28.19	$28.03	$27.98	$27.61	$27.67	$27.80	$27.54	$28.14	$28.27	$28.13
PG&E Corp	$45.64	$45.87	$45.87	$45.68	$45.30	$44.78	$44.72	$44.61	$44.29	$43.63	$43.52	$43.64	$43.63	$43.78	$43.20	$44.54
Public Service Enterprise Group Inc	$38.80	$38.74	$38.59	$38.14	$37.83	$37.00	$37.05	$37.26	$36.91	$36.82	$36.82	$37.44	$37.62	$37.88	$37.86	$37.65
Pinnacle West Capital Corp	$54.99	$55.09	$55.42	$54.86	$55.06	$55.01	$54.82	$54.94	$54.50	$54.52	$54.72	$55.18	$54.93	$55.16	$54.97	$54.94
Portland General Electric Co	$32.94	$32.88	$33.07	$32.99	$33.20	$33.18	$32.75	$32.83	$32.60	$32.87	$32.72	$33.04	$32.79	$32.87	$32.64	$32.89
SCANA Corp	$51.74	$51.88	$52.00	$51.52	$51.59	$51.20	$51.22	$51.37	$50.82	$50.83	$50.86	$51.63	$51.48	$51.69	$51.62	$51.43
Southern Co/The	$43.67	$43.67	$43.78	$43.54	$43.45	$43.16	$43.08	$43.19	$42.84	$42.77	$42.82	$43.51	$43.44	$43.73	$43.31	$43.33
Sempra Energy	$100.52	$100.47	$100.35	$100.05	$99.71	$99.06	$99.14	$98.50	$98.15	$97.16	$97.08	$98.20	$97.84	$98.49	$97.69	$98.83
Integrys Energy Group Inc	$57.85	$57.60	$57.99	$57.34	$57.23	$57.64	$57.14	$57.41	$57.03	$56.67	$56.59	$56.92	$56.62	$57.09	$56.71	$57.19
Vectren Corp	$39.69	$39.74	$39.88	$39.53	$39.59	$39.36	$38.98	$39.00	$38.39	$38.49	$38.65	$38.97	$38.86	$39.15	$38.57	$39.12
Wisconsin Energy Corp	$45.39	$45.45	$45.52	$45.10	$45.32	$45.14	$45.13	$45.11	$44.64	$44.83	$44.79	$45.37	$45.55	$45.79	$45.14	$45.22
Westar Energy Inc	$35.87	$35.69	$35.70	$35.45	$35.48	$35.21	$35.13	$35.15	$34.76	$34.61	$34.62	$35.29	$35.02	$35.14	$35.08	$35.21
Xcel Energy Inc	$30.68	$30.67	$30.76	$30.57	$30.50	$30.37	$30.24	$30.30	$30.04	$30.09	$30.06	$30.50	$30.58	$30.85	$30.57	$30.45

Sources and Notes:
Bloomberg as of June 3, 2014.
Daily prices for the 15-trading day period ending June 3, 2014.

Workpaper #2 to Table No. MJV-6

Electric Sample

Most Recent Paid Dividends

Company	Most Recent Dividend
ALLETE Inc	$0.49
Ameren Corp	$0.40
American Electric Power Co Inc	$0.50
Black Hills Corp	$0.39
CMS Energy Corp	$0.27
Cleco Corp	$0.40
CenterPoint Energy Inc	$0.24
Dominion Resources Inc/VA	$0.60
DTE Energy Co	$0.66
Consolidated Edison Inc	$0.63
El Paso Electric Co	$0.27
Edison International	$0.36
Entergy Corp	$0.83
Great Plains Energy Inc	$0.23
Hawaiian Electric Industries Inc	$0.31
IDACORP Inc	$0.43
Alliant Energy Corp	$0.51
MGE Energy Inc	$0.27
NextEra Energy Inc	$0.73
OGE Energy Corp	$0.23
Otter Tail Corp	$0.30
PG&E Corp	$0.46
Public Service Enterprise Group Inc	$0.37
Pinnacle West Capital Corp	$0.57
Portland General Electric Co	$0.28
SCANA Corp	$0.53
Southern Co/The	$0.53
Sempra Energy	$0.66
Integrys Energy Group Inc	$0.68
Vectren Corp	$0.36
Wisconsin Energy Corp	$0.39
Westar Energy Inc	$0.35
Xcel Energy Inc	$0.30

Sources and Notes:
Bloomberg as of June 3, 2014.

Workpaper #3 to Table No. MJV-6

DCF Cost of Equity of the Electric Sample

Multi - Stage DCF (using Blue Chip Economic Indicator Long-Term GDP Growth Forecast as the Perpetual Growth Rate)

Year	Company	ALLETE Inc	Ameren Corp	American Electric Power Co Inc	Black Hills Corp	CMS Energy Corp	Cleco Corp	CenterPoint Energy Inc	Dominion Resources Inc/VA	DTE Energy Co	Consolidated Edison Inc	El Paso Electric Co
	Current Dividend	$0.49	$0.40	$0.50	$0.39	$0.27	$0.40	$0.24	$0.60	$0.66	$0.63	$0.27
	Current Stock Price	($49.27)	($38.92)	($52.30)	($56.67)	($29.30)	($51.34)	($23.84)	($69.04)	($75.51)	($54.63)	($36.90)
YEAR 2014	Dividend Q3 Estimate	$0.50	$0.41	$0.51	$0.40	$0.27	$0.41	$0.24	$0.61	$0.66	$0.64	$0.27
YEAR 2014	Dividend Q4 Estimate	$0.51	$0.41	$0.51	$0.40	$0.28	$0.41	$0.24	$0.62	$0.67	$0.64	$0.27
YEAR 2015	Dividend Q1 Estimate	$0.51	$0.42	$0.52	$0.41	$0.28	$0.42	$0.25	$0.62	$0.68	$0.65	$0.27
YEAR 2015	Dividend Q2 Estimate	$0.52	$0.43	$0.53	$0.41	$0.29	$0.43	$0.25	$0.63	$0.69	$0.65	$0.28
YEAR 2015	Dividend Q3 Estimate	$0.53	$0.44	$0.54	$0.42	$0.29	$0.43	$0.25	$0.64	$0.70	$0.66	$0.28
YEAR 2015	Dividend Q4 Estimate	$0.54	$0.44	$0.54	$0.43	$0.29	$0.44	$0.26	$0.65	$0.71	$0.66	$0.28
YEAR 2016	Dividend Q1 Estimate	$0.55	$0.45	$0.55	$0.43	$0.30	$0.45	$0.26	$0.66	$0.72	$0.67	$0.29
YEAR 2016	Dividend Q2 Estimate	$0.56	$0.46	$0.56	$0.44	$0.30	$0.46	$0.26	$0.67	$0.73	$0.67	$0.29
YEAR 2016	Dividend Q3 Estimate	$0.57	$0.47	$0.57	$0.45	$0.31	$0.46	$0.27	$0.68	$0.74	$0.68	$0.30
YEAR 2016	Dividend Q4 Estimate	$0.58	$0.48	$0.57	$0.45	$0.31	$0.47	$0.27	$0.69	$0.74	$0.69	$0.30
YEAR 2017	Dividend Q1 Estimate	$0.59	$0.48	$0.58	$0.46	$0.32	$0.48	$0.28	$0.70	$0.75	$0.69	$0.30
YEAR 2017	Dividend Q2 Estimate	$0.60	$0.49	$0.59	$0.47	$0.32	$0.49	$0.28	$0.71	$0.76	$0.70	$0.31
YEAR 2017	Dividend Q3 Estimate	$0.61	$0.50	$0.60	$0.48	$0.33	$0.50	$0.28	$0.72	$0.77	$0.70	$0.31
YEAR 2017	Dividend Q4 Estimate	$0.62	$0.51	$0.60	$0.48	$0.33	$0.50	$0.29	$0.73	$0.78	$0.71	$0.31
YEAR 2018	Dividend Q1 Estimate	$0.63	$0.52	$0.61	$0.49	$0.34	$0.51	$0.29	$0.74	$0.79	$0.72	$0.32
YEAR 2018	Dividend Q2 Estimate	$0.64	$0.53	$0.62	$0.50	$0.34	$0.52	$0.29	$0.75	$0.80	$0.72	$0.32
YEAR 2018	Dividend Q3 Estimate	$0.65	$0.54	$0.63	$0.51	$0.34	$0.53	$0.30	$0.76	$0.81	$0.73	$0.33
YEAR 2018	Dividend Q4 Estimate	$0.66	$0.55	$0.64	$0.51	$0.35	$0.54	$0.30	$0.77	$0.83	$0.73	$0.33
YEAR 2019	Dividend Q1 Estimate	$0.67	$0.56	$0.65	$0.52	$0.35	$0.55	$0.31	$0.78	$0.84	$0.74	$0.33
YEAR 2019	Dividend Q2 Estimate	$0.68	$0.57	$0.66	$0.53	$0.36	$0.56	$0.31	$0.79	$0.85	$0.75	$0.34
YEAR 2019	Dividend Q3 Estimate	$0.69	$0.57	$0.67	$0.54	$0.37	$0.57	$0.32	$0.80	$0.86	$0.75	$0.34
YEAR 2019	Dividend Q4 Estimate	$0.70	$0.58	$0.67	$0.54	$0.37	$0.57	$0.32	$0.81	$0.87	$0.76	$0.35
YEAR 2020	Dividend Q1 Estimate	$0.71	$0.59	$0.68	$0.55	$0.38	$0.58	$0.32	$0.82	$0.88	$0.77	$0.35
YEAR 2020	Dividend Q2 Estimate	$0.72	$0.60	$0.69	$0.56	$0.38	$0.59	$0.33	$0.83	$0.89	$0.77	$0.35
YEAR 2020	Dividend Q3 Estimate	$0.74	$0.61	$0.70	$0.57	$0.39	$0.60	$0.33	$0.84	$0.90	$0.78	$0.36
YEAR 2020	Dividend Q4 Estimate	$0.75	$0.62	$0.71	$0.58	$0.39	$0.61	$0.34	$0.85	$0.91	$0.79	$0.36
YEAR 2021	Dividend Q1 Estimate	$0.76	$0.63	$0.72	$0.58	$0.40	$0.62	$0.34	$0.86	$0.92	$0.80	$0.37
YEAR 2021	Dividend Q2 Estimate	$0.77	$0.64	$0.73	$0.59	$0.40	$0.63	$0.35	$0.87	$0.94	$0.80	$0.37
YEAR 2021	Dividend Q3 Estimate	$0.78	$0.65	$0.74	$0.60	$0.41	$0.64	$0.35	$0.88	$0.95	$0.81	$0.37
YEAR 2021	Dividend Q4 Estimate	$0.79	$0.66	$0.75	$0.61	$0.41	$0.65	$0.35	$0.89	$0.96	$0.82	$0.38
YEAR 2022	Dividend Q1 Estimate	$0.80	$0.67	$0.76	$0.62	$0.42	$0.65	$0.36	$0.90	$0.97	$0.83	$0.38
YEAR 2022	Dividend Q2 Estimate	$0.81	$0.68	$0.76	$0.62	$0.42	$0.66	$0.36	$0.92	$0.98	$0.84	$0.39
YEAR 2022	Dividend Q3 Estimate	$0.82	$0.69	$0.77	$0.63	$0.43	$0.67	$0.37	$0.93	$0.99	$0.85	$0.39
YEAR 2022	Dividend Q4 Estimate	$0.83	$0.70	$0.78	$0.64	$0.43	$0.68	$0.37	$0.94	$1.00	$0.85	$0.40
YEAR 2023	Dividend Q1 Estimate	$0.84	$0.71	$0.79	$0.65	$0.44	$0.69	$0.38	$0.95	$1.02	$0.86	$0.40
YEAR 2023	Dividend Q2 Estimate	$0.85	$0.71	$0.80	$0.66	$0.44	$0.70	$0.38	$0.96	$1.03	$0.87	$0.41
YEAR 2023	Dividend Q3 Estimate	$0.86	$0.72	$0.81	$0.66	$0.45	$0.71	$0.38	$0.97	$1.04	$0.88	$0.41
YEAR 2023	Dividend Q4 Estimate	$0.87	$0.73	$0.82	$0.67	$0.45	$0.72	$0.39	$0.98	$1.05	$0.89	$0.41
YEAR 2024	Dividend Q1 Estimate	$0.89	$0.74	$0.83	$0.68	$0.46	$0.72	$0.39	$0.99	$1.06	$0.90	$0.42
YEAR 2024	Dividend Q2 Estimate	$0.90	$0.75	$0.84	$0.69	$0.46	$0.73	$0.40	$1.01	$1.08	$0.91	$0.42
YEAR 2024 Q3	Year 10 Stock Price	$80.17	$63.67	$83.85	$90.87	$47.11	$82.95	$38.23	$110.45	$120.46	$85.75	$58.54
	Trial COE: Quarterly Rate	2.3%	2.3%	2.1%	1.9%	2.1%	2.0%	2.2%	2.0%	2.0%	2.2%	1.9%
	Trial COE: Annual Rate	9.4%	9.6%	8.8%	7.8%	8.8%	8.3%	9.0%	8.4%	8.4%	9.1%	7.6%
	Cost of Equity	9.4%	9.6%	8.8%	7.8%	8.8%	8.3%	9.0%	8.4%	8.4%	9.1%	7.6%
	(Trial COE - COE) x 100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Sources and Notes:
All Growth Rate Estimates: Table No. MJV-6; Panel B.
Stock Prices and Dividends are from Bloomberg as of June 3, 2014.
1. See Workpaper #1 to Table No. MJV-6 for the average closing stock price obtained from Bloomberg.
2. See Workpaper #2 to Table No. MJV-6 for the for the quarterly dividend obtained from Bloomberg.
3. The Blue Chip Economic Indicator Long-Term GDP Growth Rate is used to calculate the Year 10 Stock Price.
Year 10 Stock Price = {(the Dividend Year 2024 Q3 Estimate) x ((1 + the Perpetual Growth Rate) ^ (1/4) x (1 + Quarterly Rate))} / {(Quarterly Rate) - ((1 + the Perpetual Growth Rate) ^ (1/4) -1)}.

Workpaper #3 to Table No. MJV-6

DCF Cost of Equity of the Electric Sample

Multi - Stage DCF (using Blue Chip Economic Indicator Long-Term GDP Growth Forecast as the Perpetual Growth Rate)

Year	Company	Edison International	Entergy Corp	Great Plains Energy Inc	Hawaiian Electric Industries Inc	IDACORP Inc	Alliant Energy Corp	MGE Energy Inc	NextEra Energy Inc	OGE Energy Corp	Otter Tail Corp	PG&E Corp
	Current Dividend	$0.36	$0.83	$0.23	$0.31	$0.43	$0.51	$0.27	$0.73	$0.23	$0.30	$0.46
	Current Stock Price	($54.72)	($74.44)	($25.20)	($23.83)	($54.24)	($57.42)	($36.97)	($96.01)	($36.02)	($28.13)	($44.54)
YEAR 2014	Dividend Q3 Estimate	$0.36	$0.83	$0.23	$0.31	$0.43	$0.52	$0.28	$0.74	$0.23	$0.31	$0.47
YEAR 2014	Dividend Q4 Estimate	$0.37	$0.83	$0.24	$0.32	$0.44	$0.52	$0.28	$0.75	$0.23	$0.31	$0.48
YEAR 2015	Dividend Q1 Estimate	$0.37	$0.84	$0.24	$0.32	$0.44	$0.53	$0.28	$0.76	$0.23	$0.32	$0.48
YEAR 2015	Dividend Q2 Estimate	$0.37	$0.84	$0.24	$0.32	$0.44	$0.53	$0.29	$0.77	$0.23	$0.32	$0.49
YEAR 2015	Dividend Q3 Estimate	$0.38	$0.84	$0.24	$0.33	$0.44	$0.54	$0.29	$0.78	$0.24	$0.33	$0.50
YEAR 2015	Dividend Q4 Estimate	$0.38	$0.84	$0.25	$0.33	$0.45	$0.54	$0.30	$0.79	$0.24	$0.34	$0.51
YEAR 2016	Dividend Q1 Estimate	$0.38	$0.85	$0.25	$0.33	$0.45	$0.55	$0.30	$0.81	$0.24	$0.34	$0.51
YEAR 2016	Dividend Q2 Estimate	$0.39	$0.85	$0.25	$0.34	$0.45	$0.56	$0.31	$0.82	$0.25	$0.35	$0.52
YEAR 2016	Dividend Q3 Estimate	$0.39	$0.85	$0.26	$0.34	$0.46	$0.56	$0.31	$0.83	$0.25	$0.36	$0.53
YEAR 2016	Dividend Q4 Estimate	$0.40	$0.85	$0.26	$0.34	$0.46	$0.57	$0.32	$0.85	$0.25	$0.36	$0.54
YEAR 2017	Dividend Q1 Estimate	$0.40	$0.86	$0.26	$0.35	$0.46	$0.58	$0.32	$0.86	$0.26	$0.37	$0.55
YEAR 2017	Dividend Q2 Estimate	$0.40	$0.86	$0.27	$0.35	$0.46	$0.58	$0.32	$0.87	$0.26	$0.38	$0.56
YEAR 2017	Dividend Q3 Estimate	$0.41	$0.86	$0.27	$0.36	$0.47	$0.59	$0.33	$0.89	$0.26	$0.38	$0.56
YEAR 2017	Dividend Q4 Estimate	$0.41	$0.86	$0.27	$0.36	$0.47	$0.60	$0.33	$0.90	$0.27	$0.39	$0.57
YEAR 2018	Dividend Q1 Estimate	$0.42	$0.86	$0.28	$0.36	$0.47	$0.60	$0.34	$0.91	$0.27	$0.40	$0.58
YEAR 2018	Dividend Q2 Estimate	$0.42	$0.87	$0.28	$0.37	$0.48	$0.61	$0.34	$0.93	$0.27	$0.40	$0.59
YEAR 2018	Dividend Q3 Estimate	$0.43	$0.87	$0.28	$0.37	$0.48	$0.62	$0.35	$0.94	$0.28	$0.41	$0.60
YEAR 2018	Dividend Q4 Estimate	$0.43	$0.87	$0.29	$0.37	$0.48	$0.62	$0.36	$0.96	$0.28	$0.42	$0.61
YEAR 2019	Dividend Q1 Estimate	$0.43	$0.87	$0.29	$0.38	$0.48	$0.63	$0.36	$0.97	$0.28	$0.43	$0.62
YEAR 2019	Dividend Q2 Estimate	$0.44	$0.88	$0.29	$0.38	$0.49	$0.64	$0.37	$0.99	$0.29	$0.43	$0.63
YEAR 2019	Dividend Q3 Estimate	$0.44	$0.88	$0.30	$0.39	$0.49	$0.64	$0.37	$1.00	$0.29	$0.44	$0.64
YEAR 2019	Dividend Q4 Estimate	$0.45	$0.88	$0.30	$0.39	$0.49	$0.65	$0.38	$1.01	$0.30	$0.45	$0.65
YEAR 2020	Dividend Q1 Estimate	$0.45	$0.89	$0.31	$0.40	$0.50	$0.66	$0.38	$1.03	$0.30	$0.46	$0.66
YEAR 2020	Dividend Q2 Estimate	$0.46	$0.89	$0.31	$0.40	$0.50	$0.66	$0.39	$1.04	$0.30	$0.46	$0.67
YEAR 2020	Dividend Q3 Estimate	$0.46	$0.90	$0.31	$0.40	$0.51	$0.67	$0.39	$1.06	$0.31	$0.47	$0.67
YEAR 2020	Dividend Q4 Estimate	$0.47	$0.90	$0.32	$0.41	$0.51	$0.68	$0.40	$1.07	$0.31	$0.48	$0.68
YEAR 2021	Dividend Q1 Estimate	$0.47	$0.91	$0.32	$0.41	$0.51	$0.69	$0.40	$1.09	$0.32	$0.49	$0.69
YEAR 2021	Dividend Q2 Estimate	$0.48	$0.91	$0.32	$0.42	$0.52	$0.69	$0.41	$1.10	$0.32	$0.49	$0.70
YEAR 2021	Dividend Q3 Estimate	$0.48	$0.92	$0.33	$0.42	$0.52	$0.70	$0.41	$1.12	$0.32	$0.50	$0.71
YEAR 2021	Dividend Q4 Estimate	$0.49	$0.92	$0.33	$0.43	$0.53	$0.71	$0.42	$1.13	$0.33	$0.51	$0.72
YEAR 2022	Dividend Q1 Estimate	$0.49	$0.93	$0.34	$0.43	$0.53	$0.72	$0.43	$1.15	$0.33	$0.51	$0.73
YEAR 2022	Dividend Q2 Estimate	$0.50	$0.94	$0.34	$0.44	$0.54	$0.73	$0.43	$1.16	$0.33	$0.52	$0.74
YEAR 2022	Dividend Q3 Estimate	$0.50	$0.94	$0.34	$0.44	$0.54	$0.73	$0.44	$1.18	$0.34	$0.53	$0.75
YEAR 2022	Dividend Q4 Estimate	$0.51	$0.95	$0.35	$0.44	$0.55	$0.74	$0.44	$1.19	$0.34	$0.54	$0.76
YEAR 2023	Dividend Q1 Estimate	$0.51	$0.96	$0.35	$0.45	$0.55	$0.75	$0.45	$1.21	$0.35	$0.54	$0.77
YEAR 2023	Dividend Q2 Estimate	$0.52	$0.97	$0.36	$0.45	$0.56	$0.76	$0.45	$1.22	$0.35	$0.55	$0.78
YEAR 2023	Dividend Q3 Estimate	$0.52	$0.98	$0.36	$0.46	$0.56	$0.77	$0.46	$1.24	$0.35	$0.56	$0.79
YEAR 2023	Dividend Q4 Estimate	$0.53	$0.99	$0.36	$0.46	$0.57	$0.78	$0.46	$1.25	$0.36	$0.56	$0.80
YEAR 2024	Dividend Q1 Estimate	$0.54	$1.00	$0.37	$0.47	$0.57	$0.78	$0.47	$1.27	$0.36	$0.57	$0.81
YEAR 2024	Dividend Q2 Estimate	$0.54	$1.01	$0.37	$0.47	$0.58	$0.79	$0.47	$1.28	$0.37	$0.58	$0.82
YEAR 2024 Q3	Year 10 Stock Price	$86.25	$114.11	$40.15	$37.81	$84.53	$90.96	$59.28	$154.31	$57.24	$46.27	$72.15
	Trial COE: Quarterly Rate	1.8%	2.0%	2.1%	2.4%	1.8%	2.0%	1.9%	2.0%	1.8%	2.4%	2.3%
	Trial COE: Annual Rate	7.2%	8.3%	8.5%	10.0%	7.5%	8.3%	8.0%	8.1%	7.3%	10.0%	9.4%
	Cost of Equity	7.2%	8.3%	8.5%	10.0%	7.5%	8.3%	8.0%	8.1%	7.3%	10.0%	9.4%
	(Trial COE - COE) x 100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Sources and Notes:
All Growth Rate Estimates: Table No. MJV-6; Panel B.
Stock Prices and Dividends are from Bloomberg as of June 3, 2014.
1. See Workpaper #1 to Table No. MJV-6 for the average closing stock price obtained from Bloomberg.
2. See Workpaper #2 to Table No. MJV-6 for the for the quarterly dividend obtained from Bloomberg.
3. The Blue Chip Economic Indicator Long-Term GDP Growth Rate is used to calculate the Year 10 Stock Price.
Year 10 Stock Price = {(the Dividend Year 2024 Q3 Estimate) x ((1 + the Perpetual Growth Rate) ^ (1/4) x (1 + Quarterly Rate))} /
{(Quarterly Rate) - ((1 + the Perpetual Growth Rate) ^ (1/4) -1)}.

Workpaper #3 to Table No. MJV-6

DCF Cost of Equity of the Electric Sample

Multi - Stage DCF (using Blue Chip Economic Indicator Long-Term GDP Growth Forecast as the Perpetual Growth Rate)

Year	Company	Public Service Enterprise Group Inc	Pinnacle West Capital Corp	Portland General Electric Co	SCANA Corp	Southern Co/The	Sempra Energy	Integrys Energy Group Inc	Vectren Corp	Wisconsin Energy Corp	Westar Energy Inc	Xcel Energy Inc
	Current Dividend	$0.37	$0.57	$0.28	$0.53	$0.53	$0.66	$0.68	$0.36	$0.39	$0.35	$0.30
	Current Stock Price	($37.65)	($54.94)	($32.89)	($51.43)	($43.33)	($98.83)	($57.19)	($39.12)	($45.22)	($35.21)	($30.45)
YEAR 2014	Dividend Q3 Estimate	$0.37	$0.57	$0.28	$0.53	$0.53	$0.68	$0.69	$0.36	$0.39	$0.35	$0.30
YEAR 2014	Dividend Q4 Estimate	$0.38	$0.58	$0.28	$0.54	$0.54	$0.70	$0.70	$0.37	$0.40	$0.36	$0.31
YEAR 2015	Dividend Q1 Estimate	$0.38	$0.59	$0.29	$0.54	$0.54	$0.71	$0.71	$0.37	$0.40	$0.36	$0.31
YEAR 2015	Dividend Q2 Estimate	$0.39	$0.59	$0.29	$0.55	$0.55	$0.72	$0.72	$0.38	$0.41	$0.36	$0.32
YEAR 2015	Dividend Q3 Estimate	$0.39	$0.60	$0.30	$0.56	$0.55	$0.73	$0.72	$0.38	$0.41	$0.37	$0.32
YEAR 2015	Dividend Q4 Estimate	$0.40	$0.60	$0.30	$0.56	$0.56	$0.75	$0.73	$0.39	$0.42	$0.37	$0.32
YEAR 2016	Dividend Q1 Estimate	$0.40	$0.61	$0.31	$0.57	$0.56	$0.76	$0.74	$0.39	$0.43	$0.38	$0.33
YEAR 2016	Dividend Q2 Estimate	$0.41	$0.62	$0.31	$0.58	$0.57	$0.77	$0.75	$0.40	$0.43	$0.38	$0.33
YEAR 2016	Dividend Q3 Estimate	$0.41	$0.62	$0.32	$0.59	$0.57	$0.79	$0.76	$0.40	$0.44	$0.38	$0.34
YEAR 2016	Dividend Q4 Estimate	$0.42	$0.63	$0.32	$0.59	$0.58	$0.80	$0.77	$0.41	$0.44	$0.39	$0.34
YEAR 2017	Dividend Q1 Estimate	$0.42	$0.64	$0.33	$0.60	$0.58	$0.81	$0.78	$0.42	$0.45	$0.39	$0.35
YEAR 2017	Dividend Q2 Estimate	$0.43	$0.64	$0.33	$0.61	$0.59	$0.83	$0.79	$0.42	$0.45	$0.40	$0.35
YEAR 2017	Dividend Q3 Estimate	$0.43	$0.65	$0.34	$0.61	$0.60	$0.84	$0.80	$0.43	$0.46	$0.40	$0.35
YEAR 2017	Dividend Q4 Estimate	$0.44	$0.66	$0.34	$0.62	$0.60	$0.86	$0.81	$0.43	$0.46	$0.40	$0.36
YEAR 2018	Dividend Q1 Estimate	$0.44	$0.67	$0.35	$0.63	$0.61	$0.87	$0.82	$0.44	$0.47	$0.41	$0.36
YEAR 2018	Dividend Q2 Estimate	$0.45	$0.67	$0.35	$0.64	$0.61	$0.89	$0.83	$0.44	$0.48	$0.41	$0.37
YEAR 2018	Dividend Q3 Estimate	$0.45	$0.68	$0.36	$0.64	$0.62	$0.90	$0.84	$0.45	$0.48	$0.42	$0.37
YEAR 2018	Dividend Q4 Estimate	$0.46	$0.69	$0.36	$0.65	$0.63	$0.92	$0.85	$0.45	$0.49	$0.42	$0.38
YEAR 2019	Dividend Q1 Estimate	$0.46	$0.69	$0.37	$0.66	$0.63	$0.94	$0.86	$0.46	$0.49	$0.42	$0.38
YEAR 2019	Dividend Q2 Estimate	$0.47	$0.70	$0.37	$0.67	$0.64	$0.95	$0.88	$0.47	$0.50	$0.43	$0.39
YEAR 2019	Dividend Q3 Estimate	$0.47	$0.71	$0.38	$0.68	$0.64	$0.97	$0.89	$0.47	$0.51	$0.43	$0.39
YEAR 2019	Dividend Q4 Estimate	$0.48	$0.72	$0.38	$0.68	$0.65	$0.99	$0.90	$0.48	$0.51	$0.44	$0.40
YEAR 2020	Dividend Q1 Estimate	$0.48	$0.73	$0.39	$0.69	$0.66	$1.00	$0.91	$0.48	$0.52	$0.44	$0.40
YEAR 2020	Dividend Q2 Estimate	$0.49	$0.73	$0.40	$0.70	$0.66	$1.02	$0.92	$0.49	$0.52	$0.45	$0.41
YEAR 2020	Dividend Q3 Estimate	$0.49	$0.74	$0.40	$0.71	$0.67	$1.03	$0.93	$0.50	$0.53	$0.45	$0.41
YEAR 2020	Dividend Q4 Estimate	$0.50	$0.75	$0.41	$0.72	$0.68	$1.05	$0.94	$0.50	$0.54	$0.46	$0.42
YEAR 2021	Dividend Q1 Estimate	$0.51	$0.76	$0.41	$0.73	$0.68	$1.07	$0.95	$0.51	$0.54	$0.46	$0.42
YEAR 2021	Dividend Q2 Estimate	$0.51	$0.77	$0.42	$0.74	$0.69	$1.08	$0.97	$0.52	$0.55	$0.47	$0.43
YEAR 2021	Dividend Q3 Estimate	$0.52	$0.77	$0.42	$0.74	$0.70	$1.10	$0.98	$0.52	$0.56	$0.47	$0.43
YEAR 2021	Dividend Q4 Estimate	$0.52	$0.78	$0.43	$0.75	$0.71	$1.11	$0.99	$0.53	$0.56	$0.48	$0.44
YEAR 2022	Dividend Q1 Estimate	$0.53	$0.79	$0.44	$0.76	$0.71	$1.13	$1.00	$0.53	$0.57	$0.48	$0.44
YEAR 2022	Dividend Q2 Estimate	$0.54	$0.80	$0.44	$0.77	$0.72	$1.15	$1.01	$0.54	$0.58	$0.49	$0.45
YEAR 2022	Dividend Q3 Estimate	$0.54	$0.81	$0.45	$0.78	$0.73	$1.16	$1.02	$0.55	$0.58	$0.49	$0.46
YEAR 2022	Dividend Q4 Estimate	$0.55	$0.82	$0.45	$0.79	$0.74	$1.18	$1.04	$0.55	$0.59	$0.50	$0.46
YEAR 2023	Dividend Q1 Estimate	$0.55	$0.83	$0.46	$0.80	$0.74	$1.19	$1.05	$0.56	$0.60	$0.50	$0.47
YEAR 2023	Dividend Q2 Estimate	$0.56	$0.83	$0.46	$0.81	$0.75	$1.21	$1.06	$0.57	$0.60	$0.51	$0.47
YEAR 2023	Dividend Q3 Estimate	$0.57	$0.84	$0.47	$0.81	$0.76	$1.22	$1.07	$0.57	$0.61	$0.51	$0.48
YEAR 2023	Dividend Q4 Estimate	$0.57	$0.85	$0.47	$0.82	$0.77	$1.24	$1.08	$0.58	$0.62	$0.52	$0.48
YEAR 2024	Dividend Q1 Estimate	$0.58	$0.86	$0.48	$0.83	$0.78	$1.25	$1.10	$0.59	$0.62	$0.52	$0.49
YEAR 2024	Dividend Q2 Estimate	$0.59	$0.87	$0.49	$0.84	$0.78	$1.27	$1.11	$0.59	$0.63	$0.53	$0.49
YEAR 2024 Q3	Year 10 Stock Price	$59.86	$87.02	$52.97	$81.98	$68.41	$159.75	$91.63	$62.51	$72.00	$55.65	$48.70
	Trial COE: Quarterly Rate	2.1%	2.1%	2.1%	2.2%	2.3%	1.9%	2.4%	2.1%	2.0%	2.1%	2.2%
	Trial COE: Annual Rate	8.7%	8.8%	8.5%	9.0%	9.5%	7.9%	9.8%	8.6%	8.3%	8.6%	8.9%
	Cost of Equity	8.7%	8.8%	8.5%	9.0%	9.5%	7.9%	9.8%	8.6%	8.3%	8.6%	8.9%
	(Trial COE - COE) x 100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Sources and Notes:
All Growth Rate Estimates: Table No. MJV-6; Panel B.
Stock Prices and Dividends are from Bloomberg as of June 3, 2014.
1. See Workpaper #1 to Table No. MJV-6 for the average closing stock price obtained from Bloomberg.
2. See Workpaper #2 to Table No. MJV-6 for the for the quarterly dividend obtained from Bloomberg.
3. The Blue Chip Economic Indicator Long-Term GDP Growth Rate is used to calculate the Year 10 Stock Price.
Year 10 Stock Price = {(the Dividend Year 2024 Q3 Estimate) x ((1 + the Perpetual Growth Rate) ^ (1/4) x (1 + Quarterly Rate))} /
{(Quarterly Rate) - ((1 + the Perpetual Growth Rate) ^ (1/4) -1)}.

Table No. MJV-7

Overall After-Tax DCF Cost of Capital of the Electric Sample

Panel A: Simple DCF Method (Quarterly)

Company	Full Sample	4th Quarter, 2013 Bond Rating [1]	4th Quarter, 2013 Preferred Equity Rating [2]	DCF Cost of Equity [3]	DCF Common Equity to Market Value Ratio [4]	Cost of Preferred Equity [5]	DCF Preferred Equity to Market Value Ratio [6]	DCF Cost of Debt [7]	DCF Debt to Market Value Ratio [8]	The Companies's Income Tax Rate [9]	Overall After-Tax Cost of Capital [10]
ALLETE Inc	*	BBB	-	11.1%	0.64	-	0.00	4.6%	0.36	41.5%	8.1%
Ameren Corp	*	BBB	-	11.6%	0.59	-	0.00	4.6%	0.41	41.5%	8.0%
American Electric Power Co Inc	*	BBB	-	9.7%	0.56	-	0.00	4.6%	0.44	41.5%	6.6%
Black Hills Corp	*	BBB	-	9.3%	0.62	-	0.00	4.6%	0.38	41.5%	6.8%
CMS Energy Corp	*	BBB	-	9.9%	0.48	-	0.00	4.6%	0.52	41.5%	6.1%
Cleco Corp	*	BBB	-	10.2%	0.69	-	0.00	4.6%	0.31	41.5%	7.8%
CenterPoint Energy Inc	*	A	-	9.8%	0.54	-	0.00	4.3%	0.46	41.5%	6.4%
Dominion Resources Inc/VA	*	A	A	9.3%	0.64	4.3%	0.00	4.3%	0.36	41.5%	6.8%
DTE Energy Co	*	BBB	-	9.0%	0.61	-	0.00	4.6%	0.39	41.5%	6.5%
Consolidated Edison Inc	*	A	-	8.3%	0.56	-	0.00	4.3%	0.44	41.5%	5.8%
El Paso Electric Co	*	BBB	-	8.0%	0.59	-	0.00	4.6%	0.41	41.5%	5.8%
Edison International	*	BBB	BBB	6.9%	0.58	4.6%	0.06	4.6%	0.37	41.5%	~~5.2%~~
Entergy Corp	*	BBB	BBB	5.7%	0.51	4.6%	0.01	4.6%	0.48	41.5%	~~4.2%~~
Great Plains Energy Inc	*	BBB	BBB	9.0%	0.51	4.6%	0.01	4.6%	0.49	41.5%	5.9%
Hawaiian Electric Industries Inc	*	BBB	BBB	9.8%	0.56	4.6%	0.01	4.6%	0.43	41.5%	6.7%
IDACORP Inc	*	BBB	-	5.9%	0.63	-	0.00	4.6%	0.37	41.5%	~~4.7%~~
Alliant Energy Corp	*	A	A	8.3%	0.62	4.3%	0.02	4.3%	0.36	41.5%	6.1%
MGE Energy Inc	*	AA	-	9.3%	0.75	-	0.00	4.1%	0.25	41.5%	7.6%
NextEra Energy Inc	*	A	-	9.6%	0.59	-	0.00	4.3%	0.41	41.5%	6.7%
OGE Energy Corp	*	A	-	8.0%	0.71	-	0.00	4.3%	0.29	41.5%	6.4%
Otter Tail Corp	*	BBB	-	12.1%	0.70	-	0.00	4.6%	0.30	41.5%	9.3%
PG&E Corp	*	BBB	BBB	10.7%	0.58	4.6%	0.01	4.6%	0.41	41.5%	7.4%
Public Service Enterprise Group Inc	*	BBB	-	8.9%	0.68	-	0.00	4.6%	0.32	41.5%	6.9%
Pinnacle West Capital Corp	*	A	-	8.7%	0.63	-	0.00	4.3%	0.37	41.5%	6.4%
Portland General Electric Co	*	BBB	-	9.9%	0.55	-	0.00	4.6%	0.45	41.5%	6.7%
SCANA Corp	*	BBB	-	9.3%	0.55	-	0.00	4.6%	0.45	41.5%	6.3%
Southern Co/The	*	A	A	9.1%	0.62	4.3%	0.02	4.3%	0.36	41.5%	6.6%
Sempra Energy	*	BBB	BBB	10.2%	0.65	4.6%	0.00	4.6%	0.35	41.5%	7.5%
Integrys Energy Group Inc	*	A	A	10.3%	0.60	4.3%	0.01	4.3%	0.40	41.5%	7.1%
Vectren Corp	*	A	-	9.3%	0.63	-	0.00	4.3%	0.37	41.5%	6.8%
Wisconsin Energy Corp	*	A	A	8.8%	0.67	4.3%	0.00	4.3%	0.33	41.5%	6.7%
Westar Energy Inc	*	BBB	-	8.4%	0.55	-	0.00	4.6%	0.45	41.5%	5.8%
Xcel Energy Inc	*	A	-	9.5%	0.56	-	0.00	4.3%	0.44	41.5%	6.4%
Simple Full Sample Average				9.5%	0.61	4.4%	0.00	4.5%	0.39	41.5%	6.8%

Sources and Notes:
[1]: Bloomberg as of June 3, 2014.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. MJV-6; Panel A, [6].
[4]: Table No. MJV-4, [1].
[5]: Workpaper #2 to Table No. MJV-11, Panel C.
[6]: Table No. MJV-4, [2].
[7]: Workpaper #2 to Table No. MJV-11, Panel B.
[8]: Table No. MJV-4, [3].
[9]: Provided by The Companies.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 250 basis points

Table No. MJV-7

Overall After-Tax DCF Cost of Capital of the Electric Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company	Full Sample	4th Quarter, 2013 Bond Rating [1]	4th Quarter, 2013 Preferred Equity Rating [2]	DCF Cost of Equity [3]	DCF Common Equity to Market Value Ratio [4]	Cost of Preferred Equity [5]	DCF Preferred Equity to Market Value Ratio [6]	DCF Cost of Debt [7]	DCF Debt to Market Value Ratio [8]	The Companies's Income Tax Rate [9]	Overall After-Tax Cost of Capital [10]
ALLETE Inc	*	BBB	-	9.4%	0.64	-	0.00	4.6%	0.36	41.5%	7.0%
Ameren Corp	*	BBB	-	9.6%	0.59	-	0.00	4.6%	0.41	41.5%	6.8%
American Electric Power Co Inc	*	BBB	-	8.8%	0.56	-	0.00	4.6%	0.44	41.5%	6.1%
Black Hills Corp	*	BBB	-	7.8%	0.62	-	0.00	4.6%	0.38	41.5%	5.9%
CMS Energy Corp	*	BBB	-	8.8%	0.48	-	0.00	4.6%	0.52	41.5%	5.6%
Cleco Corp	*	BBB	-	8.3%	0.69	-	0.00	4.6%	0.31	41.5%	6.6%
CenterPoint Energy Inc	*	A	-	9.0%	0.54	-	0.00	4.3%	0.46	41.5%	6.0%
Dominion Resources Inc/VA	*	A	A	8.4%	0.64	4.3%	0.00	4.3%	0.36	41.5%	6.3%
DTE Energy Co	*	BBB	-	8.4%	0.61	-	0.00	4.6%	0.39	41.5%	6.2%
Consolidated Edison Inc	*	A	-	9.1%	0.56	-	0.00	4.3%	0.44	41.5%	6.2%
El Paso Electric Co	*	BBB	-	7.6%	0.59	-	0.00	4.6%	0.41	41.5%	5.6%
Edison International	*	BBB	BBB	7.2%	0.58	4.6%	0.06	4.6%	0.37	41.5%	5.4%
Entergy Corp	*	BBB	BBB	8.3%	0.51	4.6%	0.01	4.6%	0.48	41.5%	5.6%
Great Plains Energy Inc	*	BBB	BBB	8.5%	0.51	4.6%	0.01	4.6%	0.49	41.5%	5.7%
Hawaiian Electric Industries Inc	*	BBB	BBB	10.0%	0.56	4.6%	0.01	4.6%	0.43	41.5%	6.8%
IDACORP Inc	*	BBB	-	7.5%	0.63	-	0.00	4.6%	0.37	41.5%	5.7%
Alliant Energy Corp	*	A	A	8.3%	0.62	4.3%	0.02	4.3%	0.36	41.5%	6.1%
MGE Energy Inc	*	AA	-	8.0%	0.75	-	0.00	4.1%	0.25	41.5%	6.6%
NextEra Energy Inc	*	A	-	8.1%	0.59	-	0.00	4.3%	0.41	41.5%	5.8%
OGE Energy Corp	*	A	-	7.3%	0.71	-	0.00	4.3%	0.29	41.5%	5.9%
Otter Tail Corp	*	BBB	-	10.0%	0.70	-	0.00	4.6%	0.30	41.5%	7.8%
PG&E Corp	*	BBB	BBB	9.4%	0.58	4.6%	0.01	4.6%	0.41	41.5%	6.6%
Public Service Enterprise Group Inc	*	BBB	-	8.7%	0.68	-	0.00	4.6%	0.32	41.5%	6.8%
Pinnacle West Capital Corp	*	A	-	8.8%	0.63	-	0.00	4.3%	0.37	41.5%	6.5%
Portland General Electric Co	*	BBB	-	8.5%	0.55	-	0.00	4.6%	0.45	41.5%	5.9%
SCANA Corp	*	BBB	-	9.0%	0.55	-	0.00	4.6%	0.45	41.5%	6.1%
Southern Co/The	*	A	A	9.5%	0.62	4.3%	0.02	4.3%	0.36	41.5%	6.9%
Sempra Energy	*	BBB	BBB	7.9%	0.65	4.6%	0.00	4.6%	0.35	41.5%	6.1%
Integrys Energy Group Inc	*	A	A	9.8%	0.60	4.3%	0.01	4.3%	0.40	41.5%	6.8%
Vectren Corp	*	A	-	8.6%	0.63	-	0.00	4.3%	0.37	41.5%	6.3%
Wisconsin Energy Corp	*	A	A	8.3%	0.67	4.3%	0.00	4.3%	0.33	41.5%	6.4%
Westar Energy Inc	*	BBB	-	8.6%	0.55	-	0.00	4.6%	0.45	41.5%	6.0%
Xcel Energy Inc	*	A	-	8.9%	0.56	-	0.00	4.3%	0.44	41.5%	6.1%
Multi Full Sample Average				8.6%	0.60	4.5%	0.00	4.5%	0.39	41.5%	6.2%

Sources and Notes:
[1]: Bloomberg as of June 3, 2014.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. MJV-6; Panel B, [10].
[4]: Table No. MJV-4, [1].
[5]: Workpaper #2 to Table No. MJV-11, Panel C.
[6]: Table No. MJV-4, [2].
[7]: Workpaper #2 to Table No. MJV-11, Panel B.
[8]: Table No. MJV-4, [3].
[9]: Provided by The Companies.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}. A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 250 basis points

Table No. MJV-8

DCF Cost of Equity at The Companies' Representative Capital Structure

Electric Sample

	Overall After -Tax Cost of Capital [1]	The Companies' Representative Regulatory % Debt [2]	Representative Cost of BBB-Rated Utility Debt [3]	The Companies's Income Tax Rate [4]	The Companies' Representative Regulatory % Equity [5]	Estimated Return on Equity [6]
Full Sample						
Simple DCF Quarterly	6.8%	50.0%	4.6%	41.5%	50.0%	10.9%
Multi-Stage DCF - Using the Blue Chip Economic Indicator Long-Term GDP Growth Forecast as the Perpetual Rate	6.2%	50.0%	4.6%	41.5%	50.0%	9.8%

Sources and Notes:
[1]: Table No. MJV-7; Panels A-B, [10].
[2]: Provided by The Companies. Note that the 50% debt ratio figure approximates the FE Utilities' proposed debt ratios.
[3]: Based on a BBB rating. Yield from Bloomberg as of June 3, 2014.
[4]: Provided by The Companies.
[5]: Provided by The Companies.
[6]: {[1] - ([2] x [3] x (1 - [4]) + x)} / [5].

Table No. MJV-9 Risk-Free Rates

US Interest Rate Series (All Constant Maturity Series)

	Trading Date	30 Day	90 Day	180 Day	1 Year	2 Year	3 Year	5 Year	7 Year	10 Year	Long Term
	5/13/2014	0.03%	0.03%	0.05%	0.10%	0.39%	0.84%	1.62%	2.16%	2.61%	3.17%
	5/14/2014	0.02%	0.03%	0.05%	0.10%	0.39%	0.81%	1.57%	2.10%	2.54%	3.09%
	5/15/2014	0.01%	0.03%	0.05%	0.09%	0.38%	0.80%	1.55%	2.05%	2.50%	3.05%
	5/16/2014	0.01%	0.03%	0.05%	0.09%	0.38%	0.80%	1.56%	2.08%	2.52%	3.07%
	5/19/2014	0.01%	0.03%	0.05%	0.09%	0.36%	0.79%	1.56%	2.09%	2.54%	3.11%
	5/20/2014	0.04%	0.03%	0.06%	0.09%	0.35%	0.77%	1.53%	2.06%	2.52%	3.10%
	5/21/2014	0.04%	0.04%	0.06%	0.09%	0.37%	0.79%	1.55%	2.08%	2.54%	3.13%
	5/22/2014	0.03%	0.03%	0.05%	0.09%	0.37%	0.80%	1.57%	2.10%	2.56%	3.15%
	5/23/2014	0.04%	0.04%	0.05%	0.10%	0.37%	0.79%	1.55%	2.09%	2.54%	3.12%
	5/27/2014	0.03%	0.04%	0.06%	0.09%	0.39%	0.79%	1.56%	2.08%	2.52%	3.09%
	5/28/2014	0.04%	0.04%	0.05%	0.10%	0.37%	0.76%	1.50%	2.01%	2.44%	3.01%
	5/29/2014	0.05%	0.04%	0.05%	0.10%	0.37%	0.77%	1.52%	2.03%	2.45%	3.03%
	5/30/2014	0.05%	0.04%	0.06%	0.10%	0.37%	0.79%	1.54%	2.06%	2.48%	3.05%
	6/2/2014	0.04%	0.04%	0.06%	0.10%	0.39%	0.83%	1.60%	2.12%	2.54%	3.10%
	6/3/2014	0.04%	0.04%	0.06%	0.10%	0.41%	0.85%	1.65%	2.18%	2.60%	3.17%
[A]	Average:	0.03%	0.04%	0.05%	0.10%	0.38%	0.80%	1.56%	2.09%	2.53%	3.10%

Sources and Notes:

[A]: Average over the last 15 trading days.

Bloomberg as of June 3, 2014. The most recent 15 trading days are used.

Workpaper #1 to Table No. MJV-9 - Risk Premium Forecast

Electric Sample

Panel A: Historical Bond Yield Averages

	Treasury Bill Yield [1]	Intermediate-Term Government Bond Yield [2]	Long-Term Government Bond Yield [3]
1926	3.27%	3.61%	3.54%
1927	3.12%	3.40%	3.17%
1928	3.56%	4.01%	3.40%
1929	4.75%	3.62%	3.40%
1930	2.41%	2.91%	3.30%
1931	1.07%	4.12%	4.07%
1932	0.96%	3.04%	3.15%
1933	0.30%	3.25%	3.36%
1934	0.16%	2.49%	2.93%
1935	0.17%	1.63%	2.76%
1936	0.18%	1.29%	2.55%
1937	0.31%	1.14%	2.73%
1938	-0.02%	1.52%	2.52%
1939	0.02%	0.98%	2.26%
1940	0.00%	0.57%	1.94%
1941	0.06%	0.82%	2.04%
1942	0.27%	0.72%	2.46%
1943	0.35%	1.45%	2.48%
1944	0.33%	1.40%	2.46%
1945	0.33%	1.03%	1.99%
1946	0.35%	1.12%	2.12%
1947	0.50%	1.34%	2.43%
1948	0.81%	1.51%	2.37%
1949	1.10%	1.23%	2.09%
1950	1.20%	1.62%	2.24%
1951	1.49%	2.17%	2.69%
1952	1.66%	2.35%	2.79%
1953	1.82%	2.18%	2.74%
1954	0.86%	1.72%	2.72%
1955	1.57%	2.80%	2.95%
1956	2.46%	3.63%	3.45%
1957	3.14%	2.84%	3.23%
1958	1.54%	3.81%	3.82%
1959	2.95%	4.98%	4.47%
1960	2.66%	3.31%	3.80%
1961	2.13%	3.84%	4.15%
1962	2.73%	3.50%	3.95%
1963	3.12%	4.04%	4.17%
1964	3.54%	4.03%	4.23%
1965	3.93%	4.90%	4.50%
1966	4.76%	4.79%	4.55%
1967	4.21%	5.77%	5.56%
1968	5.21%	5.96%	5.98%
1969	6.58%	8.29%	6.87%
1970	6.52%	5.90%	6.48%
1971	4.39%	5.25%	5.97%
1972	3.84%	5.85%	5.99%
1973	6.93%	6.79%	7.26%
1974	8.00%	7.12%	7.60%
1975	5.80%	7.19%	8.05%
1976	5.08%	6.00%	7.21%

Workpaper #1 to Table No. MJV-9 - Risk Premium Forecast

Electric Sample

Panel A: Historical Bond Yield Averages

	Treasury Bill Yield [1]	Intermediate-Term Government Bond Yield [2]	Long-Term Government Bond Yield [3]
1977	5.12%	7.51%	8.03%
1978	7.18%	8.83%	8.98%
1979	10.38%	10.33%	10.12%
1980	11.24%	12.45%	11.99%
1981	14.71%	13.96%	13.34%
1982	10.54%	9.90%	10.95%
1983	8.80%	11.41%	11.97%
1984	9.85%	11.04%	11.70%
1985	7.72%	8.55%	9.56%
1986	6.16%	6.85%	7.89%
1987	5.47%	8.32%	9.20%
1988	6.35%	9.17%	9.19%
1989	8.37%	7.94%	8.16%
1990	7.81%	7.70%	8.44%
1991	5.60%	5.97%	7.30%
1992	3.51%	6.11%	7.26%
1993	2.90%	5.22%	6.54%
1994	3.90%	7.80%	7.99%
1995	5.60%	5.38%	6.03%
1996	5.21%	6.16%	6.73%
1997	5.26%	5.73%	6.02%
1998	4.86%	4.68%	5.42%
1999	4.68%	6.45%	6.82%
2000	5.89%	5.07%	5.58%
2001	3.83%	4.42%	5.75%
2002	1.65%	2.61%	4.84%
2003	1.02%	2.97%	5.11%
2004	1.20%	3.47%	4.84%
2005	2.98%	4.34%	4.61%
2006	4.80%	4.65%	4.91%
2007	4.66%	3.28%	4.50%
2008	1.60%	1.26%	3.03%
2009	0.10%	2.42%	4.58%
2010	0.12%	1.70%	4.14%
2011	0.04%	0.59%	2.48%
2012	0.06%	0.46%	2.41%

[1] - [3]: Ibbotson Associates Stocks Bonds Bills (SBBI) and Inflation monthly paper reports.

Workpaper #1 to Table No. MJV-9

Electric Sample

Panel B: Calculation of Maturity Premia for Different Bond Series

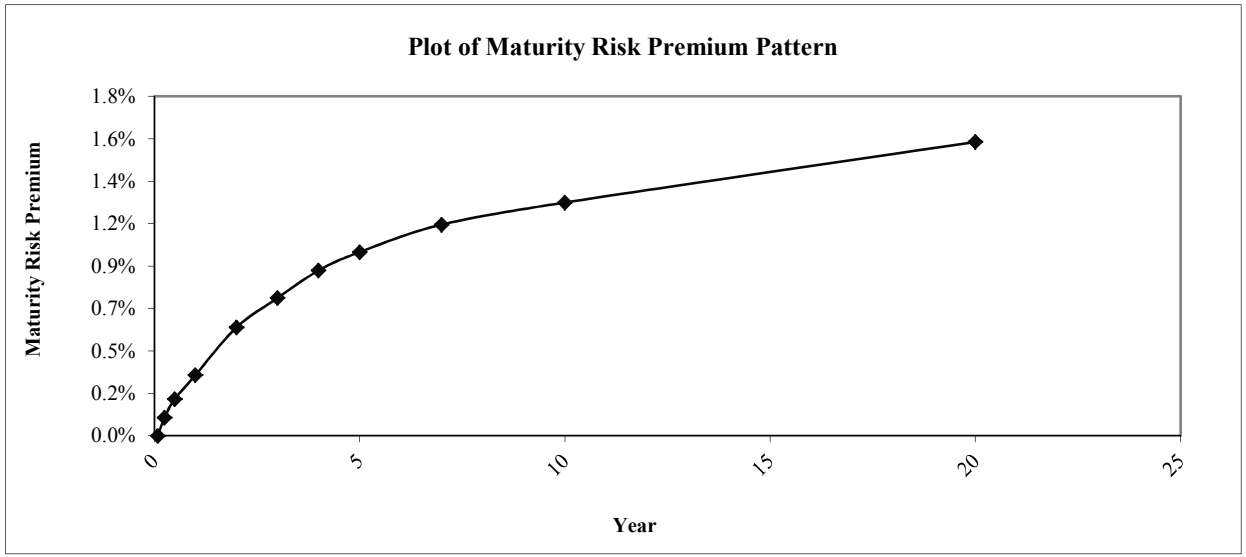
	Annual Historical Average			Maturity Premium Calculation		
	T-Bill Total Return [1]	Intermediate Term Bond Yields [2]	Long-Term Government Bond Yield [3]	T-Bill [4]	Intermediate Term Bond [5]	Long-Term Government [6]
1926 - 2012	3.58%	4.52%	5.16%	0.00%	0.94%	1.58%
1947 - 2012	4.39%	5.29%	5.92%	0.00%	0.90%	1.53%
1947 - 1966	2.20%	3.03%	3.37%	0.00%	0.83%	1.17%
1967 - 1986	7.41%	8.25%	8.57%	0.00%	0.83%	1.16%
1987 - 2012	3.75%	4.76%	5.84%	0.00%	1.02%	2.09%
Current	0.03%	1.56%	3.10%	0.00%	1.53%	3.06%

Sources and Notes:
[1] - [3] : Workpaper #1 to Table No. MJV-9, Panel A.
Maturity Premium is defined as the Average Bond Yield (for each series) less Risk Free Total Return.
[4]: [1] - [1].
[5]: [2] - [1].
[6]: [3] - [1].
Current data from Table No. MJV-9, Panel A.

Workpaper #1 to Table No. MJV-9

Electric Sample

Panel C: Maturity Premium Graph and Calculations (Using Annual Series Data)



Maturity of Bond (Years) [1]	Maturity Risk Premium [2]	Annualized Difference [3]
0.083	0.00%	
0.25	0.10%	0.60%
0.5	0.20%	0.40%
1	0.33%	0.26%
2	0.59%	0.26%
3	0.75%	0.16%
4	0.90%	0.15%
5	**1.00%**	0.10%
7	1.15%	0.08%
10	1.27%	0.04%
20	**1.60%**	0.03%

Sources and Notes:
[1]: The maturity of a bond in years.
[2]: Workpaper #1 to Table No. MJV-9, Panel B; [4] - [6] and MJV Testimony.
[3]: MJV Testimony.

Table No. MJV-10

Risk Positioning Cost of Equity of the Electric Sample

Using Value Line Betas

Panel A: Scenario 1 - Long-Term Risk Free Rate of 3.35%, Long-Term Market Risk Premium of 6.50%

Company	Long-Term Risk-Free Rate [1]	Value Line Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (0.5%) Cost of Equity [5]	ECAPM (1.5%) Cost of Equity [6]
ALLETE Inc	3.35%	0.80	6.50%	8.5%	8.6%	8.8%
Ameren Corp	3.35%	0.85	6.50%	8.9%	8.9%	9.1%
American Electric Power Co Inc	3.35%	0.70	6.50%	7.9%	8.0%	8.3%
Black Hills Corp	3.35%	0.90	6.50%	9.2%	9.2%	9.3%
CMS Energy Corp	3.35%	0.70	6.50%	7.9%	8.0%	8.3%
Cleco Corp	3.35%	0.70	6.50%	7.9%	8.0%	8.3%
CenterPoint Energy Inc	3.35%	0.85	6.50%	8.9%	8.9%	9.1%
Dominion Resources Inc/VA	3.35%	0.75	6.50%	8.2%	8.3%	8.6%
DTE Energy Co	3.35%	0.85	6.50%	8.9%	8.9%	9.1%
Consolidated Edison Inc	3.35%	0.65	6.50%	7.6%	7.7%	8.1%
El Paso Electric Co	3.35%	0.70	6.50%	7.9%	8.0%	8.3%
Edison International	3.35%	0.80	6.50%	8.5%	8.6%	8.8%
Entergy Corp	3.35%	0.75	6.50%	8.2%	8.3%	8.6%
Great Plains Energy Inc	3.35%	0.90	6.50%	9.2%	9.2%	9.3%
Hawaiian Electric Industries Inc	3.35%	0.85	6.50%	8.9%	8.9%	9.1%
IDACORP Inc	3.35%	0.80	6.50%	8.5%	8.6%	8.8%
Alliant Energy Corp	3.35%	0.80	6.50%	8.5%	8.6%	8.8%
MGE Energy Inc	3.35%	0.70	6.50%	7.9%	8.0%	8.3%
NextEra Energy Inc	3.35%	0.75	6.50%	8.2%	8.3%	8.6%
OGE Energy Corp	3.35%	0.85	6.50%	8.9%	8.9%	9.1%
Otter Tail Corp	3.35%	0.95	6.50%	9.5%	9.5%	9.6%
PG&E Corp	3.35%	0.60	6.50%	7.2%	7.4%	7.8%
Public Service Enterprise Group Inc	3.35%	0.80	6.50%	8.5%	8.6%	8.8%
Pinnacle West Capital Corp	3.35%	0.75	6.50%	8.2%	8.3%	8.6%
Portland General Electric Co	3.35%	0.80	6.50%	8.5%	8.6%	8.8%
SCANA Corp	3.35%	0.75	6.50%	8.2%	8.3%	8.6%
Southern Co/The	3.35%	0.60	6.50%	7.2%	7.4%	7.8%
Sempra Energy	3.35%	0.80	6.50%	8.5%	8.6%	8.8%
Integrys Energy Group Inc	3.35%	1.05	6.50%	10.2%	10.1%	10.1%
Vectren Corp	3.35%	0.75	6.50%	8.2%	8.3%	8.6%
Wisconsin Energy Corp	3.35%	0.70	6.50%	7.9%	8.0%	8.3%
Westar Energy Inc	3.35%	0.80	6.50%	8.5%	8.6%	8.8%
Xcel Energy Inc	3.35%	0.65	6.50%	7.6%	7.7%	8.1%

Sources and Notes:
[1]: Vilbert Direct Testimony.
[2]: From Valueline Investment Analyzer as of June 3, 2014.
[3]: Vilbert Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 0.5%) + [2] x ([3] - 0.5%).
[6]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. MJV-10

Risk Positioning Cost of Equity of the Electric Sample

Using Value Line Betas

Panel B: Scenario 2 - Long-Term Risk Free Rate of 3.10%, Long-Term Market Risk Premium of 7.50%

Company	Long-Term Risk-Free Rate [1]	Value Line Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (0.5%) Cost of Equity [5]	ECAPM (1.5%) Cost of Equity [6]
ALLETE Inc	3.10%	0.80	7.50%	9.1%	9.2%	9.4%
Ameren Corp	3.10%	0.85	7.50%	9.5%	9.5%	9.7%
American Electric Power Co Inc	3.10%	0.70	7.50%	8.3%	8.5%	8.8%
Black Hills Corp	3.10%	0.90	7.50%	9.8%	9.9%	10.0%
CMS Energy Corp	3.10%	0.70	7.50%	8.3%	8.5%	8.8%
Cleco Corp	3.10%	0.70	7.50%	8.3%	8.5%	8.8%
CenterPoint Energy Inc	3.10%	0.85	7.50%	9.5%	9.5%	9.7%
Dominion Resources Inc/VA	3.10%	0.75	7.50%	8.7%	8.8%	9.1%
DTE Energy Co	3.10%	0.85	7.50%	9.5%	9.5%	9.7%
Consolidated Edison Inc	3.10%	0.65	7.50%	8.0%	8.1%	8.5%
El Paso Electric Co	3.10%	0.70	7.50%	8.3%	8.5%	8.8%
Edison International	3.10%	0.80	7.50%	9.1%	9.2%	9.4%
Entergy Corp	3.10%	0.75	7.50%	8.7%	8.8%	9.1%
Great Plains Energy Inc	3.10%	0.90	7.50%	9.8%	9.9%	10.0%
Hawaiian Electric Industries Inc	3.10%	0.85	7.50%	9.5%	9.5%	9.7%
IDACORP Inc	3.10%	0.80	7.50%	9.1%	9.2%	9.4%
Alliant Energy Corp	3.10%	0.80	7.50%	9.1%	9.2%	9.4%
MGE Energy Inc	3.10%	0.70	7.50%	8.3%	8.5%	8.8%
NextEra Energy Inc	3.10%	0.75	7.50%	8.7%	8.8%	9.1%
OGE Energy Corp	3.10%	0.85	7.50%	9.5%	9.5%	9.7%
Otter Tail Corp	3.10%	0.95	7.50%	10.2%	10.2%	10.3%
PG&E Corp	3.10%	0.60	7.50%	7.6%	7.8%	8.2%
Public Service Enterprise Group Inc	3.10%	0.80	7.50%	9.1%	9.2%	9.4%
Pinnacle West Capital Corp	3.10%	0.75	7.50%	8.7%	8.8%	9.1%
Portland General Electric Co	3.10%	0.80	7.50%	9.1%	9.2%	9.4%
SCANA Corp	3.10%	0.75	7.50%	8.7%	8.8%	9.1%
Southern Co/The	3.10%	0.60	7.50%	7.6%	7.8%	8.2%
Sempra Energy	3.10%	0.80	7.50%	9.1%	9.2%	9.4%
Integrys Energy Group Inc	3.10%	1.05	7.50%	11.0%	10.9%	10.9%
Vectren Corp	3.10%	0.75	7.50%	8.7%	8.8%	9.1%
Wisconsin Energy Corp	3.10%	0.70	7.50%	8.3%	8.5%	8.8%
Westar Energy Inc	3.10%	0.80	7.50%	9.1%	9.2%	9.4%
Xcel Energy Inc	3.10%	0.65	7.50%	8.0%	8.1%	8.5%

Sources and Notes:
[1]: Vilbert Direct Testimony.
[2]: From Valueline Investment Analyzer as of June 3, 2014.
[3]: Vilbert Direct Testimony.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 0.5%) + [2] x ([3] - 0.5%).
[6]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Workpaper # 1 to Table No. MJV-10

Electric Sample

Value Line Betas

Company	Value Line Betas [1]
ALLETE Inc	0.80
Ameren Corp	0.85
American Electric Power Co Inc	0.70
Black Hills Corp	0.90
CMS Energy Corp	0.70
Cleco Corp	0.70
CenterPoint Energy Inc	0.85
Dominion Resources Inc/VA	0.75
DTE Energy Co	0.85
Consolidated Edison Inc	0.65
El Paso Electric Co	0.70
Edison International	0.80
Entergy Corp	0.75
Great Plains Energy Inc	0.90
Hawaiian Electric Industries Inc	0.85
IDACORP Inc	0.80
Alliant Energy Corp	0.80
MGE Energy Inc	0.70
NextEra Energy Inc	0.75
OGE Energy Corp	0.85
Otter Tail Corp	0.95
PG&E Corp	0.60
Public Service Enterprise Group Inc	0.80
Pinnacle West Capital Corp	0.75
Portland General Electric Co	0.80
SCANA Corp	0.75
Southern Co/The	0.60
Sempra Energy	0.80
Integrys Energy Group Inc	1.05
Vectren Corp	0.75
Wisconsin Energy Corp	0.70
Westar Energy Inc	0.80
Xcel Energy Inc	0.65
Average	0.78

Sources and Notes:
[1]: From Valueline Investment Analyzer as of June 3, 2014.

Table No. MJV-11

Overall After-Tax Cost of Capital of the Electric Sample

Using Value Line Betas

Panel A: CAPM Cost of Equity Scenario 1 - Long-Term Risk Free Rate of 3.35%, Long-Term Market Risk Premium of 6.50%

Company	CAPM Cost of Equity [1]	ECAPM (0.5%) Cost of Equity [2]	ECAPM (1.5%) Cost of Equity [3]	5-Year Average Common Equity to Market Value Ratio [4]	Weighted - Average Cost of Preferred Equity [5]	5-Year Average Preferred Equity to Market Value Ratio [6]	Weighted-Average Cost of Debt [7]	5-Year Average Debt to Market Value Ratio [8]	The Companies's Income Tax Rate [9]	Overall After-Tax Cost of Capital (CAPM) [10]	Overall After-Tax Cost of Capital (ECAPM 0.5%) [11]	Overall After-Tax Cost of Capital (ECAPM 1.5%) [12]
ALLETE Inc	8.5%	8.6%	8.8%	0.59	4.60%	0.00	4.6%	0.41	41.5%	6.2%	6.2%	6.3%
Ameren Corp	8.9%	8.9%	9.1%	0.47	4.60%	0.00	4.6%	0.53	41.5%	5.6%	5.6%	5.7%
American Electric Power Co Inc	7.9%	8.0%	8.3%	0.47	4.60%	0.00	4.6%	0.53	41.5%	5.1%	5.2%	5.3%
Black Hills Corp	9.2%	9.2%	9.3%	0.49	4.60%	0.00	4.6%	0.51	41.5%	5.9%	5.9%	5.9%
CMS Energy Corp	7.9%	8.0%	8.3%	0.37	4.60%	0.00	4.6%	0.62	41.5%	4.6%	4.7%	4.8%
Cleco Corp	7.9%	8.0%	8.3%	0.57	4.60%	0.00	4.6%	0.43	41.5%	5.7%	5.8%	5.9%
CenterPoint Energy Inc	8.9%	8.9%	9.1%	0.41	4.54%	0.00	4.5%	0.59	41.5%	5.2%	5.2%	5.3%
Dominion Resources Inc/VA	8.2%	8.3%	8.6%	0.56	4.28%	0.01	4.3%	0.44	41.5%	5.7%	5.8%	5.9%
DTE Energy Co	8.9%	8.9%	9.1%	0.49	4.60%	0.00	4.6%	0.51	41.5%	5.7%	5.8%	5.8%
Consolidated Edison Inc	7.6%	7.7%	8.1%	0.53	4.28%	0.01	4.3%	0.47	41.5%	5.2%	5.3%	5.5%
El Paso Electric Co	7.9%	8.0%	8.3%	0.58	4.60%	0.00	4.6%	0.42	41.5%	5.7%	5.8%	5.9%
Edison International	8.5%	8.6%	8.8%	0.50	4.60%	0.05	4.6%	0.44	41.5%	5.7%	5.8%	5.9%
Entergy Corp	8.2%	8.3%	8.6%	0.48	4.60%	0.01	4.6%	0.51	41.5%	5.4%	5.4%	5.5%
Great Plains Energy Inc	9.2%	9.2%	9.3%	0.41	4.60%	0.01	4.6%	0.59	41.5%	5.3%	5.4%	5.4%
Hawaiian Electric Industries Inc	8.9%	8.9%	9.1%	0.54	4.60%	0.01	4.6%	0.45	41.5%	6.0%	6.1%	6.2%
IDACORP Inc	8.5%	8.6%	8.8%	0.53	4.60%	0.00	4.6%	0.47	41.5%	5.8%	5.9%	6.0%
Alliant Energy Corp	8.5%	8.6%	8.8%	0.54	4.54%	0.03	4.5%	0.43	41.5%	5.9%	5.9%	6.0%
MGE Energy Inc	7.9%	8.0%	8.3%	0.71	4.11%	0.00	4.1%	0.29	41.5%	6.3%	6.4%	6.6%
NextEra Energy Inc	8.2%	8.3%	8.6%	0.50	4.28%	0.00	4.3%	0.50	41.5%	5.4%	5.4%	5.6%
OGE Energy Corp	8.9%	8.9%	9.1%	0.60	4.54%	0.00	4.5%	0.40	41.5%	6.4%	6.4%	6.5%
Otter Tail Corp	9.5%	9.5%	9.6%	0.61	4.60%	0.01	4.6%	0.38	41.5%	6.9%	6.9%	6.9%
PG&E Corp	7.2%	7.4%	7.8%	0.54	4.60%	0.01	4.6%	0.45	41.5%	5.2%	5.3%	5.5%
Public Service Enterprise Group Inc	8.5%	8.6%	8.8%	0.61	4.60%	0.00	4.6%	0.39	41.5%	6.3%	6.3%	6.4%
Pinnacle West Capital Corp	8.2%	8.3%	8.6%	0.53	4.54%	0.00	4.5%	0.47	41.5%	5.6%	5.7%	5.8%
Portland General Electric Co	8.5%	8.6%	8.8%	0.46	4.60%	0.00	4.6%	0.54	41.5%	5.4%	5.5%	5.5%
SCANA Corp	8.2%	8.3%	8.6%	0.48	4.60%	0.00	4.6%	0.52	41.5%	5.4%	5.4%	5.5%
Southern Co/The	7.2%	7.4%	7.8%	0.57	4.28%	0.02	4.3%	0.41	41.5%	5.3%	5.4%	5.6%
Sempra Energy	8.5%	8.6%	8.8%	0.55	4.60%	0.00	4.6%	0.45	41.5%	5.9%	6.0%	6.1%
Integrys Energy Group Inc	10.2%	10.1%	10.1%	0.57	4.47%	0.01	4.5%	0.43	41.5%	6.9%	6.9%	6.9%
Vectren Corp	8.2%	8.3%	8.6%	0.53	4.28%	0.00	4.3%	0.47	41.5%	5.6%	5.6%	5.8%
Wisconsin Energy Corp	7.9%	8.0%	8.3%	0.58	4.41%	0.00	4.4%	0.42	41.5%	5.7%	5.8%	5.9%
Westar Energy Inc	8.5%	8.6%	8.8%	0.47	4.60%	0.00	4.6%	0.53	41.5%	5.4%	5.5%	5.6%
Xcel Energy Inc	7.6%	7.7%	8.1%	0.50	4.34%	0.00	4.3%	0.50	41.5%	5.1%	5.1%	5.3%
Full Sample Average				0.53	4.51%	0.01	4.5%	0.47	41.5%	5.7%	5.7%	5.9%

Sources and Notes:

[1]: Table No. MJV-10; Panel A, [4].
[2]: Table No. MJV-10; Panel A, [5].
[3]: Table No. MJV-10; Panel A, [6].
[4]: Table No. MJV-4, [4].
[5]: Workpaper #2 to Table No. MJV-11, Panel C.
[6]: Table No. MJV-4, [5].
[7]: Workpaper #2 to Table No. MJV-11, Panel B.
[8]: Table No. MJV-4, [6].
[9]: Provided by The Companies.
[10]: ([1] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}.
[11]: ([2] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}.
[12]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}.

[10]-[12] A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 250 basis points

Table No. MJV-11

Overall After-Tax Cost of Capital of the Electric Sample

Using Value Line Betas

Panel B: CAPM Cost of Equity Scenario 2 - Long-Term Risk Free Rate of 3.10%, Long-Term Market Risk Premium of 7.50%

Company	CAPM Cost of Equity [1]	ECAPM (0.5%) Cost of Equity [2]	ECAPM (1.5%) Cost of Equity [3]	5-Year Average Common Equity to Market Value Ratio [4]	Weighted - Average Cost of Preferred Equity [5]	5-Year Average Preferred Equity to Market Value Ratio [6]	Weighted-Average Cost of Debt [7]	5-Year Average Debt to Market Value Ratio [8]	The Companies's Income Tax Rate [9]	Overall After-Tax Cost of Capital (CAPM) [10]	Overall After-Tax Cost of Capital (ECAPM 0.5%) [11]	Overall After-Tax Cost of Capital (ECAPM 1.5%) [12]
ALLETE Inc	9.1%	9.2%	9.4%	0.59	4.60%	0.00	4.6%	0.41	41.5%	6.5%	6.5%	6.7%
Ameren Corp	9.5%	9.5%	9.7%	0.47	4.60%	0.00	4.6%	0.53	41.5%	5.9%	5.9%	6.0%
American Electric Power Co Inc	8.3%	8.5%	8.8%	0.47	4.60%	0.00	4.6%	0.53	41.5%	5.3%	5.4%	5.6%
Black Hills Corp	9.8%	9.9%	10.0%	0.49	4.60%	0.00	4.6%	0.51	41.5%	6.2%	6.2%	6.2%
CMS Energy Corp	8.3%	8.5%	8.8%	0.37	4.60%	0.00	4.6%	0.62	41.5%	4.8%	4.9%	5.0%
Cleco Corp	8.3%	8.5%	8.8%	0.57	4.60%	0.00	4.6%	0.43	41.5%	5.9%	6.0%	6.2%
CenterPoint Energy Inc	9.5%	9.5%	9.7%	0.41	4.54%	0.00	4.5%	0.59	41.5%	5.4%	5.5%	5.5%
Dominion Resources Inc/VA	8.7%	8.8%	9.1%	0.56	4.28%	0.01	4.3%	0.44	41.5%	6.0%	6.0%	6.2%
DTE Energy Co	9.5%	9.5%	9.7%	0.49	4.60%	0.00	4.6%	0.51	41.5%	6.0%	6.0%	6.1%
Consolidated Edison Inc	8.0%	8.1%	8.5%	0.53	4.28%	0.01	4.3%	0.47	41.5%	5.4%	5.5%	5.7%
El Paso Electric Co	8.3%	8.5%	8.8%	0.58	4.60%	0.00	4.6%	0.42	41.5%	5.9%	6.0%	6.2%
Edison International	9.1%	9.2%	9.4%	0.50	4.60%	0.05	4.6%	0.44	41.5%	6.0%	6.1%	6.2%
Entergy Corp	8.7%	8.8%	9.1%	0.48	4.60%	0.01	4.6%	0.51	41.5%	5.6%	5.6%	5.8%
Great Plains Energy Inc	9.8%	9.9%	10.0%	0.41	4.60%	0.01	4.6%	0.59	41.5%	5.6%	5.6%	5.7%
Hawaiian Electric Industries Inc	9.5%	9.5%	9.7%	0.54	4.60%	0.01	4.6%	0.45	41.5%	6.4%	6.4%	6.5%
IDACORP Inc	9.1%	9.2%	9.4%	0.53	4.60%	0.00	4.6%	0.47	41.5%	6.1%	6.2%	6.3%
Alliant Energy Corp	9.1%	9.2%	9.4%	0.54	4.54%	0.03	4.5%	0.43	41.5%	6.2%	6.2%	6.3%
MGE Energy Inc	8.3%	8.5%	8.8%	0.71	4.11%	0.00	4.1%	0.29	41.5%	6.6%	6.7%	7.0%
NextEra Energy Inc	8.7%	8.8%	9.1%	0.50	4.28%	0.00	4.3%	0.50	41.5%	5.6%	5.7%	5.8%
OGE Energy Corp	9.5%	9.5%	9.7%	0.60	4.54%	0.00	4.5%	0.40	41.5%	6.7%	6.8%	6.9%
Otter Tail Corp	10.2%	10.2%	10.3%	0.61	4.60%	0.01	4.6%	0.38	41.5%	7.3%	7.3%	7.3%
PG&E Corp	7.6%	7.8%	8.2%	0.54	4.60%	0.01	4.6%	0.45	41.5%	5.4%	5.5%	5.7%
Public Service Enterprise Group Inc	9.1%	9.2%	9.4%	0.61	4.60%	0.00	4.6%	0.39	41.5%	6.6%	6.6%	6.8%
Pinnacle West Capital Corp	8.7%	8.8%	9.1%	0.53	4.54%	0.00	4.5%	0.47	41.5%	5.9%	6.0%	6.1%
Portland General Electric Co	9.1%	9.2%	9.4%	0.46	4.60%	0.00	4.6%	0.54	41.5%	5.7%	5.7%	5.8%
SCANA Corp	8.7%	8.8%	9.1%	0.48	4.60%	0.00	4.6%	0.52	41.5%	5.6%	5.7%	5.8%
Southern Co/The	7.6%	7.8%	8.2%	0.57	4.28%	0.02	4.3%	0.41	41.5%	5.5%	5.6%	5.8%
Sempra Energy	9.1%	9.2%	9.4%	0.55	4.60%	0.00	4.6%	0.45	41.5%	6.2%	6.3%	6.4%
Integrys Energy Group Inc	11.0%	10.9%	10.9%	0.57	4.47%	0.01	4.5%	0.43	41.5%	7.4%	7.3%	7.3%
Vectren Corp	8.7%	8.8%	9.1%	0.53	4.28%	0.00	4.3%	0.47	41.5%	5.8%	5.9%	6.0%
Wisconsin Energy Corp	8.3%	8.5%	8.8%	0.58	4.41%	0.00	4.4%	0.42	41.5%	5.9%	6.0%	6.2%
Westar Energy Inc	9.1%	9.2%	9.4%	0.47	4.60%	0.00	4.6%	0.53	41.5%	5.7%	5.7%	5.8%
Xcel Energy Inc	8.0%	8.1%	8.5%	0.50	4.34%	0.00	4.3%	0.50	41.5%	5.3%	5.4%	5.5%
Full Sample Average				0.53	4.51%	0.01	4.5%	0.47	41.5%	6.0%	6.0%	6.1%

Sources and Notes:
[1]: Table No. MJV-10; Panel B, [4].
[2]: Table No. MJV-10; Panel B, [5].
[3]: Table No. MJV-10; Panel B, [6].
[4]: Table No. MJV-4, [4].
[5]: Workpaper #2 to Table No. MJV-11, Panel C.
[6]: Table No. MJV-4, [5].
[7]: Workpaper #2 to Table No. MJV-11, Panel B.
[8]: Table No. MJV-4, [6].
[9]: Provided by The Companies.
[10]: ([1] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}.
[11]: ([2] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}.
[12]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}.
[10]-[12] A strikethrough indicates the utility was excluded from the full sample average calculation as a result of its cost of equity not exceeding its cost of debt by 250 basis points

Workpaper #1 to Table No. MJV-11

Electric Sample

Panel A: Rating to Yield Conversion

Rating	Bond Yield	Preferred Yield
A	4.28%	4.28%
BBB	4.60%	4.60%

Sources and Notes:
Bond Yields from Bloomberg as of June 03, 2014.
Preferred Yields from matching Bloomberg bond yields as of June 3, 2014.
AA estimated as A - 0.5 * (BBB - A).

Workpaper #1 to Table No. MJV-11

Electric Sample

Panel B: Bond Rating Summary

Company	Year End, June 3, 2014 [1]	2013 [2]	2012 [3]	2011 [4]	2010 [5]	2009 [6]
ALLETE Inc	BBB	BBB	BBB	BBB	BBB	BBB
Ameren Corp	BBB	BBB	BBB	BBB	BBB	BBB
American Electric Power Co Inc	BBB	BBB	BBB	BBB	BBB	BBB
Black Hills Corp	BBB	BBB	BBB	BBB	BBB	BBB
CMS Energy Corp	BBB	BBB	BBB	BBB	BBB	BBB
Cleco Corp	BBB	BBB	BBB	BBB	BBB	BBB
CenterPoint Energy Inc	A	A	BBB	BBB	BBB	BBB
Dominion Resources Inc/VA	A	A	A	A	A	A
DTE Energy Co	BBB	BBB	BBB	BBB	BBB	BBB
Consolidated Edison Inc	A	A	A	A	A	A
El Paso Electric Co	BBB	BBB	BBB	BBB	BBB	BBB
Edison International	BBB	BBB	BBB	BBB	BBB	BBB
Entergy Corp	BBB	BBB	BBB	BBB	BBB	BBB
Great Plains Energy Inc	BBB	BBB	BBB	BBB	BBB	BBB
Hawaiian Electric Industries Inc	BBB	BBB	BBB	BBB	BBB	BBB
IDACORP Inc	BBB	BBB	BBB	BBB	BBB	BBB
Alliant Energy Corp	A	A	BBB	BBB	BBB	BBB
MGE Energy Inc	AA	AA	AA	AA	AA	AA
NextEra Energy Inc	A	A	A	A	A	A
OGE Energy Corp	A	A	BBB	BBB	BBB	BBB
Otter Tail Corp	BBB	BBB	BBB	BBB	BBB	BBB
PG&E Corp	BBB	BBB	BBB	BBB	BBB	BBB
Public Service Enterprise Group Inc	BBB	BBB	BBB	BBB	BBB	BBB
Pinnacle West Capital Corp	A	A	BBB	BBB	BBB	BBB
Portland General Electric Co	BBB	BBB	BBB	BBB	BBB	BBB
SCANA Corp	BBB	BBB	BBB	BBB	BBB	BBB
Southern Co/The	A	A	A	A	A	A
Sempra Energy	BBB	BBB	BBB	BBB	BBB	BBB
Integrys Energy Group Inc	A	A	A	BBB	BBB	BBB
Vectren Corp	A	A	A	A	A	A
Wisconsin Energy Corp	A	A	A	A	BBB	BBB
Westar Energy Inc	BBB	BBB	BBB	BBB	BBB	BBB
Xcel Energy Inc	A	A	A	A	A	BBB

Sources and Notes:
[1] - [6]: Bloomberg as of June 3, 2014.

Workpaper #1 to Table No. MJV-11

Electric Sample

Panel C: Preferred Equity Rating Summary

Company	June 3, 2014 [1]	Year End, 2013 [2]	2012 [3]	2011 [4]	2010 [5]	2009 [6]
ALLETE Inc	BBB	BBB	BBB	BBB	BBB	BBB
Ameren Corp	BBB	BBB	BBB	BBB	BBB	BBB
American Electric Power Co Inc	BBB	BBB	BBB	BBB	BBB	BBB
Black Hills Corp	BBB	BBB	BBB	BBB	BBB	BBB
CMS Energy Corp	BBB	BBB	BBB	BBB	BBB	BBB
Cleco Corp	BBB	BBB	BBB	BBB	BBB	BBB
CenterPoint Energy Inc	A	A	BBB	BBB	BBB	BBB
Dominion Resources Inc/VA	A	A	A	A	A	A
DTE Energy Co	BBB	BBB	BBB	BBB	BBB	BBB
Consolidated Edison Inc	A	A	A	A	A	A
El Paso Electric Co	BBB	BBB	BBB	BBB	BBB	BBB
Edison International	BBB	BBB	BBB	BBB	BBB	BBB
Entergy Corp	BBB	BBB	BBB	BBB	BBB	BBB
Great Plains Energy Inc	BBB	BBB	BBB	BBB	BBB	BBB
Hawaiian Electric Industries Inc	BBB	BBB	BBB	BBB	BBB	BBB
IDACORP Inc	BBB	BBB	BBB	BBB	BBB	BBB
Alliant Energy Corp	A	A	BBB	BBB	BBB	BBB
MGE Energy Inc	AA	AA	AA	AA	AA	AA
NextEra Energy Inc	A	A	A	A	A	A
OGE Energy Corp	A	A	BBB	BBB	BBB	BBB
Otter Tail Corp	BBB	BBB	BBB	BBB	BBB	BBB
PG&E Corp	BBB	BBB	BBB	BBB	BBB	BBB
Public Service Enterprise Group Inc	BBB	BBB	BBB	BBB	BBB	BBB
Pinnacle West Capital Corp	A	A	BBB	BBB	BBB	BBB
Portland General Electric Co	BBB	BBB	BBB	BBB	BBB	BBB
SCANA Corp	BBB	BBB	BBB	BBB	BBB	BBB
Southern Co/The	A	A	A	A	A	A
Sempra Energy	BBB	BBB	BBB	BBB	BBB	BBB
Integrys Energy Group Inc	A	A	A	BBB	BBB	BBB
Vectren Corp	A	A	A	A	A	A
Wisconsin Energy Corp	A	A	A	A	BBB	BBB
Westar Energy Inc	BBB	BBB	BBB	BBB	BBB	BBB
Xcel Energy Inc	A	A	A	A	A	BBB

Sources and Notes:

[1] - [6]: Preferred equity ratings are assumed equal to the company's bond ratings reported in Workpaper #1 to Table No. MJV-11, Panel B.

Workpaper #2 to Table No. MJV-11

Electric Sample

Panel A: 15-Day Average Utility Yields and Mergent Preferred Yields

Date	AA Rated Utility [1]	A Rated Utility [2]	BBB Rated Utility [3]	AA Preferred [4]	A Preferred [5]	BBB Preferred [6]
5/13/2014	-	4.35	4.69	-	-	-
5/14/2014	-	4.29	4.65	-	-	-
5/15/2014	-	4.25	4.60	-	-	-
5/16/2014	-	4.26	4.61	-	-	-
5/19/2014	-	4.30	4.62	-	-	-
5/20/2014	-	4.28	4.62	-	-	-
5/21/2014	-	4.30	4.63	-	-	-
5/22/2014	-	4.31	4.63	-	-	-
5/23/2014	-	4.28	4.60	-	-	-
5/27/2014	-	4.26	4.57	-	-	-
5/28/2014	-	4.19	4.51	-	-	-
5/29/2014	-	4.22	4.52	-	-	-
5/30/2014	-	4.23	4.53	-	-	-
6/2/2014	-	4.28	4.60	-	-	-
6/3/2014	-	4.35	4.67	-	-	-
Average	4.11	4.28	4.60	4.11	4.28	4.60

Sources and Notes:
[1] - [3]: Bloomberg as of June 3, 2014.
[4] - [6]: From matching Bloomberg bond yields as of June 3, 2014.
AA estimated as A - 0.5 * (BBB - A).

Workpaper #2 to Table No. MJV-11

Electric Sample

Panel B: Bond Yield Summary

Company	June 3, 2014 [1]	Year End, 2013 [2]	2012 [3]	2011 [4]	2010 [5]	2009 [6]	5-Year Average [7]
ALLETE Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Ameren Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
American Electric Power Co Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Black Hills Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
CMS Energy Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Cleco Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
CenterPoint Energy Inc	4.28%	4.28%	4.60%	4.60%	4.60%	4.60%	4.54%
Dominion Resources Inc/VA	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%
DTE Energy Co	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Consolidated Edison Inc	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%
El Paso Electric Co	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Edison International	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Entergy Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Great Plains Energy Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Hawaiian Electric Industries Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
IDACORP Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Alliant Energy Corp	4.28%	4.28%	4.60%	4.60%	4.60%	4.60%	4.54%
MGE Energy Inc	4.11%	4.11%	4.11%	4.11%	4.11%	4.11%	4.11%
NextEra Energy Inc	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%
OGE Energy Corp	4.28%	4.28%	4.60%	4.60%	4.60%	4.60%	4.54%
Otter Tail Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
PG&E Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Public Service Enterprise Group Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Pinnacle West Capital Corp	4.28%	4.28%	4.60%	4.60%	4.60%	4.60%	4.54%
Portland General Electric Co	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
SCANA Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Southern Co/The	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%
Sempra Energy	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Integrys Energy Group Inc	4.28%	4.28%	4.28%	4.60%	4.60%	4.60%	4.47%
Vectren Corp	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%
Wisconsin Energy Corp	4.28%	4.28%	4.28%	4.28%	4.60%	4.60%	4.41%
Westar Energy Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Xcel Energy Inc	4.28%	4.28%	4.28%	4.28%	4.28%	4.60%	4.34%

Sources and Notes:
[1] - [6]: Ratings based on Workpaper #1 to Table No. MJV-11, Panel B. Bond yields from Bloomberg as of June 3, 2014.
[7]: ([2] + [3] + [4] + [5] + [6]) / 5.
AA estimated as A - 0.5 * (BBB - A).

Workpaper #2 to Table No. MJV-11

Electric Sample

Panel C: Preferred Equity Yield Summary

Company	June 3, 2014 [1]	Year End, 2013 [2]	2012 [3]	2011 [4]	2010 [5]	2009 [6]	5-Year Average [7]
ALLETE Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Ameren Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
American Electric Power Co Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Black Hills Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
CMS Energy Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Cleco Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
CenterPoint Energy Inc	4.28%	4.28%	4.60%	4.60%	4.60%	4.60%	4.54%
Dominion Resources Inc/VA	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%
DTE Energy Co	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Consolidated Edison Inc	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%
El Paso Electric Co	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Edison International	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Entergy Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Great Plains Energy Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Hawaiian Electric Industries Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
IDACORP Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Alliant Energy Corp	4.28%	4.28%	4.60%	4.60%	4.60%	4.60%	4.54%
MGE Energy Inc	4.11%	4.11%	4.11%	4.11%	4.11%	4.11%	4.11%
NextEra Energy Inc	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%
OGE Energy Corp	4.28%	4.28%	4.60%	4.60%	4.60%	4.60%	4.54%
Otter Tail Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
PG&E Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Public Service Enterprise Group Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Pinnacle West Capital Corp	4.28%	4.28%	4.60%	4.60%	4.60%	4.60%	4.54%
Portland General Electric Co	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
SCANA Corp	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Southern Co/The	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%
Sempra Energy	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Integrys Energy Group Inc	4.28%	4.28%	4.28%	4.60%	4.60%	4.60%	4.47%
Vectren Corp	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%	4.28%
Wisconsin Energy Corp	4.28%	4.28%	4.28%	4.28%	4.60%	4.60%	4.41%
Westar Energy Inc	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
Xcel Energy Inc	4.28%	4.28%	4.28%	4.28%	4.28%	4.60%	4.34%

Sources and Notes:
[1] - [6]: See Workpaper #1 to Table No. MJV-11, Panels C. Preferred equity yields are from matching Bloomberg bond yields as of June 3, 2014.
[7]: ([2] + [3] + [4] + [5] + [6]) / 5.
AA estimated as A - 0.5 * (BBB - A).

Table No. MJV-12

Risk Positioning Cost of Equity at The Companies' Representative Capital Structure

Electric Sample

Using Value Line Betas

	Overall After-Tax Cost of Capital (Scenario 1) [1]	Overall After-Tax Cost of Capital (Scenario 2) [2]	The Companies' Representative Regulatory % Debt [3]	Representative Cost of BBB-Rated Utility Debt [4]	The Companies' Income Tax Rate [5]	The Companies' Representative Regulatory % Equity [6]	Estimated Return on Equity (Scenario 1) [7]	Estimated Return on Equity (Scenario 2) [8]
Full Sample:								
CAPM using Value Line Betas	5.7%	6.0%	50.0%	4.6%	41.5%	50.0%	8.7%	9.2%
ECAPM (0.50%) using Value Line Betas	5.7%	6.0%	50.0%	4.6%	41.5%	50.0%	8.8%	9.3%
ECAPM (1.50%) using Value Line Betas	5.9%	6.1%	50.0%	4.6%	41.5%	50.0%	9.0%	9.6%

Sources and Notes:
[1]: Table No. MJV-11; Panel A, [10] - [12].
[2]: Table No. MJV-11; Panel B, [10] - [12].
[3]: Provided by The Companies.
[4]: Based on a BBB rating. Yield from Bloomberg as of June 3, 2014.
[5]: Provided by The Companies.
[6]: Provided by The Companies.
[7]: {[1] - ([3] x [4] x (1 - [5]) + x)}/ [6]
[8]: {[2] - ([3] x [4] x (1 - [5]) + x)}/ [6]

Scenario 1: Long-Term Risk Free Rate of 3.35%, Long-Term Market Risk Premium of 6.50%.
Scenario 2: Long-Term Risk Free Rate of 3.10%, Long-Term Market Risk Premium of 7.50%.

APPENDIX A:

QUALIFICATIONS OF MICHAEL J. VILBERT

Dr. Michael J. Vilbert is Office Director of The Brattle Group's San Francisco office and has 20 years of experience as an economic consultant. He is an expert in cost of capital, financial planning and valuation who has advised clients on these matters in the context of a wide variety of investment and regulatory decisions. In the area of regulatory economics, he has testified or submitted testimony on the cost of capital for regulated companies in the water, electric, natural gas and petroleum industries in the U.S. and Canada. His testimony has addressed the effect of regulatory policies such as decoupling or must-run generation on a regulated company's cost of capital and the appropriate way to estimate the cost of capital for companies organized as Master Limited Partnerships. He analyzed issues associated with situations imposing asymmetric risk on utilities, the prudence of purchased power contracts, the economics of energy conservation programs, the appropriate incentives for investment in electric transmission assets and the effect of long-term purchased power agreements on the financial risk of a company. He has served as a neutral arbitrator in a contract dispute and analyzed the effectiveness of a company's electric power supply auction. He has also estimated economic damages and analyzed the business purpose and economic substance of tax related transactions, valued assets in arbitration for purchase at the end of the contract, estimated the stranded costs of resulting from the deregulation of electric generation and from the municipalization of an electric utility's distribution assets and addressed the appropriate regulatory accounting for depreciation and goodwill.

He received his Ph.D. in Financial Economics from the Wharton School of the University of Pennsylvania, an MBA from the University of Utah, an M.S. from the Fletcher School of Law and Diplomacy, Tufts University, and a B.S. degree from the United States Air Force Academy. He joined The Brattle Group in 1994 after a career as an Air Force officer, where he served as a fighter pilot, intelligence officer, and professor of finance at the Air Force Academy. .

REPRESENTATIVE CONSULTING EXPERIENCE

- Dr. Vilbert served as the consulting expert in several cases for the U.S. Department of Justice and the Internal Revenue Service regarding the business purpose and economic substance of a series of tax related transactions. These projects required the analysis of a complex series of financial transactions including the review of voluminous documentary evidence and required expertise in financial theory, financial market as well as accounting and financial statement analysis.

- In a securities fraud case, Dr. Vilbert designed and created a model to value the private placement stock of a drug store chain as if there had been full disclosure of the actual financial condition of the firm. He analyzed key financial data and security analysts''

reports regarding the future of the industry in order to recreate pro forma balance sheet and income statements under a variety of scenarios designed to establish the value of the firm.

- For pharmaceutical companies rebutting price-fixing claims in antitrust litigation, Dr. Vilbert was a member of a team that prepared a comprehensive analysis of industry profitability. The analysis replicated, tested and critiqued the major recent analyses of drug costs, risks and returns. The analyses helped develop expert witness testimony to rebut allegations of excess profits.

- For an independent electric power producer, Dr. Vilbert created a model that analyzed the reasonableness of rates and costs filed by a natural gas pipeline. The model not only duplicated the pipeline's rates, but it also allowed simulation of a variety of "what if" scenarios associated with cost recovery under alternative time patterns and joint cost allocations. Results of the analysis were adopted by the intervenor group for negotiation with the pipeline.

- For the CFO of an electric utility, Dr. Vilbert developed the valuation model used to support a stranded cost estimation filing. The case involved a conflict between two utilities over the responsibility for out-of-market costs associated with a power purchase contract between them. In addition, he advised and analyzed cost recovery mechanisms that would allow full recovery of the stranded costs while providing a rate reduction for the company's rate payers.

- Dr. Vilbert has testified as well as assisted in the preparation of testimony and the development of estimation models in numerous cost-of-capital cases for natural gas pipeline, water utility and electric utility clients before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions. These have spanned standard estimation techniques (e.g., Discounted Cash Flow and Risk Positioning models). He has also developed and applied more advanced models specific to the industries or lines of business in question, e.g., based on the structure and risk characteristics of cash flows, or based on multi-factor models that better characterize regulated industries.

- Dr. Vilbert has valued several large, residual oil-fired generating stations to evaluate the possible conversion to natural gas or other fuels. In these analyses, the expected pre- and post-conversion station values were computed using a range of market electricity and fuel cost conditions.

- For a major western electric utility, Dr. Vilbert helped prepare testimony that analyzed the prudence of QF contract enforcement. The testimony demonstrated that the utility had not been compensated in its allowed cost of capital for major disallowances stemming from QF contract management.

- Dr. Vilbert analyzed the economic need for a major natural gas pipeline expansion to the Midwest. This involved evaluating forecasts of natural gas use in various regions of the United States and the effect of additional supplies on the pattern of natural gas pipeline

use. The analysis was used to justify the expansion before the FERC and the National Energy Board of Canada.

- For a Public Utility Commission in the Northeast, Dr. Vilbert analyzed the auction of an electric utility's purchase power agreements to determine whether the outcome of the auction was in the ratepayers' interest. The work involved the analysis of the auction procedures as well as the benefits to ratepayers of transferring risk of the PPA payments to the buyer.

- Dr. Vilbert led a team tasked to determine whether bridge tolls were "just and reasonable" for a non-profit port authority. Determination of the cost of service for the authority required estimation of the value of the authority's assets using the trended original cost methodology as well as evaluation of the operations and maintenance budgets. Investment costs, bridge traffic information and inflation indices covering a 75 year period were utilized to estimate the value of four bridges and a passenger transit line valued in excess of $1 billion.

- Dr. Vilbert helped a recently privatized railroad in Brazil develop an estimate of its revenue requirements, including a determination of the railroad's cost of capital. He also helped evaluate alternative rate structures designed to provide economic incentives to shippers as well as to the railroad for improved service. This involved the explanation and analysis of the contribution margin of numerous shipper products, improved cost analysis and evaluation of bottlenecks in the system.

- For a utility in the Southeast, Dr. Vilbert quantified the company's stranded costs under several legislative electric restructuring scenarios. This involved the evaluation of all of the company's fossil and nuclear generating units, its contracts with Qualifying Facilities and the prudence of those QF contracts. He provided analysis concerning the impact of securitizing the company's stranded costs as a means of reducing the cost to the ratepayers and several alternative designs for recovering stranded costs.

- For a recently privatized electric utility in Australia, Dr. Vilbert evaluated the proposed regulatory scheme of the Australian Competition and Consumer Commission for the company's electric transmission system. The evaluation highlighted the elements of the proposed regulation which would impose uncompensated asymmetric risks on the company and the need to either eliminate the asymmetry in risk or provide additional compensation so that the company could expect to earn its cost of capital.

- For an electric utility in the Southwest, Dr. Vilbert helped design and create a model to estimate the stranded costs of the company's portfolio of Qualifying Facilities and Power Purchase contracts. This exercise was complicated by the many variations in the provisions of the contracts that required modeling in order to capture the effect of changes in either the performance of the plants or in the estimated market price of electricity.

- Dr. Vilbert helped prepare the testimony responding to a FERC request for further

comments on the appropriate return on equity for electric transmission facilities. In addition, Dr. Vilbert was a member of the team that made a presentation to the FERC staff on the expected risks of the unbundled electric transmission line of business.

- Dr. Vilbert and Mr. Frank C. Graves, also of The Brattle Group, prepared testimony evaluating an innovative Canadian stranded cost recovery procedure involving the auctioning of the output of the province's electric generation plants instead of the plants themselves. The evaluation required the analysis of the terms and conditions of the long-term contracts specifying the revenue requirements of the plants for their entire forecasted remaining economic life and required an estimate of the cost of capital for the plant owners under this new stranded cost recovery concept.

- Dr. Vilbert served as the neutral arbitrator for the valuation of a petroleum products tanker. The valuation required analysis of the Jones Act tanker market and the supply and demand balance of the available U.S. constructed tanker fleet.

- Dr. Vilbert evaluated the appropriate "bareboat" charter rate for an oil drilling platform for the renewal period following the end of a long-term lease. The evaluation required analysis of the market for oil drilling platforms around the world including trends in construction and labor costs and the demand for platforms in varying geographical environments.

PRESENTATIONS

"Utility Distribution Cost of Capital," *EEI Electric Rates Advanced Course*, Bloomington, IN, 2002, 2003.

"Issues for Cost of Capital Estimation," with Bente Villadsen, *Edison Electric Institute Cost of Capital Conference*, Chicago, IL, February 2004.

"Not Your Father's Rate of Return Methodology," *Utility Commissioners/Wall Street Dialogue*, NY, May 2004.

"Utility Distribution Cost of Capital," *EEI Electric Rates Advanced Course*, Madison, WI, July 2004.

"Cost of Capital Estimation: Issues and Answers," *MidAmerican Regulatory Finance Conference*, Des Moines, IA, April 7, 2005.

"Cost of Capital - Explaining to the Commission - Different ROEs for Different Parts of the Business," *EEI Economic Regulation & Competition Analysts Meeting*, May 2, 2005.

"Current Issues in Cost of Capital," with Bente Villadsen, *EEI Electric Rates Advanced Course*, Madison, WI, 2005.

"Current Issues in Estimating the Cost of Capital," *EEI Electric Rates Advanced Course*, Madison, WI, 2006, 2007, 2008, 2009, 2010 and 2011.

"Revisiting the Development of Proxy Groups and Relative Risk Analysis," Society of Utility and Regulatory Financial Analysts: 39th Financial Forum, April 2007.

"Current Issues in Explaining the Cost of Capital to Utility Commissions" Cost of Capital Seminar, Philadelphia, PA, 2008.

"Impact of the Ongoing Economic Crisis on the Cost of Capital of the U.S. Utility Sector", New York Public Service Commission, Albany, NY, April 20, 2009.

"Impact of the Ongoing Economic Crisis on the Cost of Capital of the U.S. Utility Sector", National Association of Water Companies: New York Chapter, Albany, NY, May 21, 2009.

"Introduction to Retail Rates," presented to California Water Services Company, 18-19 November 2010.

"Point – Counterpoint: The Regulatory Compact and Pipeline Competition," with (Jonathan Lesser, Continental Economics), Energy Bar Association, Western Meeting, February 22, 2013

"An Empirical Study of the Impact of Decoupling on the Cost of Capital," Center for Research in Regulated Industries, Shawnee on Delaware, PA, May 17, 2013.

"The Cost of Capital for Alabama Power Company," Public Service Commission public meeting, July 17, 2013.

ARTICLES

"Flaws in the Proposed IRS Rule to Reinstate Amortization of Deferred Tax Balances Associated with Generation Assets Reorganized in Industry Restructuring," by Frank C. Graves and Michael J. Vilbert, white paper for *Edison Electric Institute* (EEI) to the IRS, July 25, 2003.

"The Effect of Debt on the Cost of Equity in a Regulatory Setting," by A. Lawrence Kolbe, Michael J. Vilbert, Bente Villadsen and The Brattle Group, *Edison Electric Institute*, April 2005.

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," by A. Lawrence Kolbe, Michael J. Vilbert and Bente Villadsen, *Public Utilities Fortnightly*, August 2005.

"Understanding Debt Imputation Issues," by Michael J. Vilbert, Bente Villadsen and Joseph B. Wharton, *Edison Electric Institute*, August 2008.

"Review of Regulatory Cost of Capital Methodologies," (with Bente Villadsen and Matthew Aharonian), Canadian Transportation Agency, September 2010.

"The Impact of Decoupling on the Cost of Capital – An Empirical Study," Joseph B. Wharton, Michael J. Vilbert, Richard E. Goldberg, and Toby Brown, Discussion Paper, *The Brattle Group*, March 2011.

"Economic Impact on City of Portland of Allocation of Remediation Costs of Portland Harbor Superfund Site," with Professor David Sunding, March 2012.

"Survey of Cost of Capital Practices in Canada," (with Bente Villadsen and Toby Brown), prepared for British Columbia Utilities Commission, May 2012.

"Estimating the Cost of Equity for Regulated Companies," (with P.R. Carpenter, Bente Villadsen, T. Brown, and P. Kumar), prepared for the Australian Pipeline Industry Association and filed with the Australian Energy Regulator and the Economic Regulation Authority, Western Australia, February 2013.

"The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation," prepared for The Energy Foundation by Michael J. Vilbert, Joseph B. Wharton, Charles Gibbons, Melanie Rosenberg, and Yang Wei Neo, March 20, 2104.

TESTIMONY

Direct and rebuttal testimony before the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation in the matter of an application for approval of its 1999 and 2000 generation tariff, transmission tariff, and distribution revenue requirement, Docket U99099, October 1998.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Central Maine Power in Docket No. ER00-982-000, December 1999.

Direct testimony before the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation for approval of its 2001 transmission tariff, May 2000.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Mississippi River Transmission Corporation in Docket No. RP01-292-000, March 2001.

Written evidence, rebuttal, reply and further reply before the National Energy Board in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part I and Part IV of the *National Energy Board Act*, Order AO-1-RH-4-2001, May 2001, Nov. 2001, Feb. 2002.

Written evidence before the Public Utility Board on behalf of Newfoundland & Labrador Hydro - Rate Hearings, October 2001, Order No. P.U.7 (2002-2003), dated June 2002.

Direct testimony (with William Lindsay) before the Federal Energy Regulatory Commission on behalf of DTE East China, LLC in Docket No. ER02-1599-000, April 2002.

Direct and rebuttal reports before the Arbitration Panel in the arbitration of stranded costs for the City of Casselberry, FL, Case No. 00-CA-1107-16-L, July 2002.

Direct reports before the Arbitration Board for Petroleum products trade in the Arbitration of the Military Sealift Command vs. Household Commercial Financial Services, fair value of sale of the Darnell, October 2002.

Direct testimony and hearing before the Arbitration Panel in the arbitration of stranded costs for the City of Winter Park, FL, In the Circuit Court of the Ninth Judicial Circuit in and for Orange County, FL, Case No. C1-01-4558-39, December 2002.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Florida Power Corporation, dba Progress Energy Florida, Inc. in Docket No. SC03-1-000, March 2003.

Direct report before the Arbitration Panel in the arbitration of stranded costs for the Town of Belleair, FL, Case No. 000-6487-C1-007, April 2003.

Direct and rebuttal reports before the Alberta Energy and Utilities Board in the matter of the Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17, and the Regulations under it; in the matter of the Gas Utilities Act, R.S.A. 2000, c. G-5, and the Regulations under it; in the matter of the Public Utilities Board Act, R.S.A. 2000, c. P-45, as amended, and the Regulations under it; and in the matter of Alberta Energy and Utilities Generic Cost of Capital Hearing, Application No. 1271597, July 2003, November 2003, Decision 2004-052, dated July 2004.

Written evidence before the National Energy Board in the matter of the National Energy Board Act, R.S.C. 1985, c. N−7, as amended, (Act) and the Regulations made under it; and in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part IV of the *National Energy Board Act*, for approval of Mainline Tolls for 2004, RH-2-2004, January 2004.

Direct and rebuttal testimony before the Public Service Commission of West Virginia, on Cost of Capital for West Virginia-American Water Company, Case No 04-0373-W-42T, May 2004.

Direct and rebuttal testimony before the Federal Energy Regulatory Commission on Energy Allocation of Debt Cost for Incremental Shipping Rates for Edison Mission Energy, Docket No. RP04-274-000, December 2004 and March 2005.

Direct testimony before the Arizona Corporation Commission, Cost of Capital for Paradise Valley Water Company, a subsidiary of Arizona-American Water Company, Docket No. WS-01303A-05, May 2005.

Written evidence before the Ontario Energy Board, Cost of Capital for Union Gas Limited, Inc., Docket No. EB-2005-0520, January 2006.

Direct and rebuttal testimony before the Pennsylvania Public Utility Commission, Return on Equity for Metropolitan Edison Company, Docket No. R-00061366 and Pennsylvania Electric Company,
Docket No. R-00061367, April 2006 and August 2006.

Expert report in the United States Tax Court, Docket No. 21309-05, 34th Street Partners, DH Petersburg Investment, LLC and Mid-Atlantic Finance, Partners Other than the Tax Matters Partner, Petitioner, v. Commissioner of Internal Revenue, Respondent, July 28, 2006.

Direct and supplemental testimony before the Federal Energy Regulatory Commission, Docket No. ER06-427-003, on behalf of Mystic Development, LLC on the Cost of Capital for Mystic 8 and 9 Generating Plants Operating Under Reliability Must Run Contract, August 2006 and September 2006.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER07-46-000, on behalf of Northwestern Corporation on the Cost of Capital for Transmission Assets, October 2006.

Direct and rebuttal testimony before the Tennessee Regulatory Authority, Case No. 06-00290, on behalf of Tennessee American Water Company, on the Cost of Capital, November, 2006 and April 2007.

Direct and rebuttal testimony before the Public Service Commission of Wisconsin, Docket No. 5-UR-103, on behalf of Wisconsin Energy Corporation, on the Cost of Capital for Wisconsin Electric Power Company and Wisconsin Gas LLC, May 2007 and October 2007.

Rebuttal testimony before the California Public Utilities Commission, Docket No. A. 07-01-036-39, on behalf of California-American Water Company, on the Cost of Capital, May 2007.

Direct testimony before the Public Utilities Commission of the State of South Dakota, Docket No. NG-07-013, on behalf of NorthWestern Corporation, on the Cost of Capital for NorthWestern Energy Company's natural gas operations in South Dakota, June 2007.

Direct, supplemental and rebuttal testimony before the Public Utilities Commission of Ohio, Case No. 07-551-EL-AIR, Case No. 07-552-EL-ATA, Case No. 07-553-EL-AAM, and Case No. 07-554-EL-UNC, on behalf of Ohio Edison Company, The Toledo Edison Company, and The Cleveland Electric Illuminating Company, on the cost of capital for the FirstEnergy Company's Ohio electric distribution utilities, June 2007, January 2008 and February 2008.

Direct testimony before the Public Service Commission of West Virginia, Case No. 07-0998-W-42T, on behalf of West Virginia American Water Company on cost of capital, July 2007.

Direct and rebuttal testimony before the State Corporation Commission of Virginia, Case No. PUE-2007-00066, on behalf of Virginia Electric and Power Company on the cost of capital for its southwest Virginia coal plant, July 2007 and December 2007.

Direct and Supplemental testimony before the Public Utilities Commission of Ohio, Case No. 07-829-GA-AIR, Case No. 07-830-GA-ALT, and Case No. 07-831-GA-AAM, on behalf of Dominion East Ohio Company, on the rate of return for Dominion East Ohio's natural gas distribution operations, September 2007 and June 2008.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER08-92-000 to Docket No. ER08-92-003, on behalf of Virginia Electric and Power Company, on the Cost of Capital for Transmission Assets, October 2007.

Direct and rebuttal testimony before the California Public Utilities Commission, Docket No. A. 07-01-022, on behalf of California-American Water Company, on the Effect of a Water Revenue Adjustment Mechanism on the Cost of Capital, October 2007 and November 2007.

Written direct and reply evidence before the National Energy Board in the matter of the National Energy Board Act, R.S.C. 1985, c. N−7, as amended, and the Regulations made thereunder; and in the matter of an application by Trans Québec & Maritimes PipeLines Inc. ("TQM") for orders pursuant to Part I and Part IV of the *National Energy Board Act*, for determining the overall fair return on capital for tolls charged by TQM, December 2007 and September 2008, Decision RH-1-2008, dated March 2009.

Comments in support of The Interstate Natural Gas Association of America's Additional Initial Comments on the FERC's Proposed Policy Statement with regard to the Composition of Proxy Companies for Determining Gas and Oil Pipeline Return on Equity, Docket No. PL07-2-000, December, 2007.

Direct and rebuttal testimony on the Cost of Capital before the Tennessee Regulatory Authority, Case No. 08-00039, on behalf of Tennessee American Water Company, March and August 2008.

Post-Technical Conference Affidavit on behalf of The Interstate Natural Gas Association of America in response to the Reply Comments of the State of Alaska with regard the FERC's Proposed Policy Statement on to the Composition of Proxy Companies for Determining Gas and Oil Pipeline Return on Equity, Docket No. PL07-2-000, March, 2008

Direct and rebuttal testimony before the California Public Utilities Commission, Docket No. A.08-05-003, on behalf of California-American Water Company, concerning Cost of Capital, May 2008 and August 2008.

Rebuttal testimony on the financial risk of Purchased Power Agreements, before the Public Utilities Commission of the State of Colorado, Docket No. 07A-447E, in the matter of the application of Public Service Company of Colorado for approval of its 2007 Colorado Resource Plan, June 2008.

Direct and rebuttal testimony before the Federal Energy Regulatory Commission, Docket No. RP08-426-000, on behalf of El Paso Natural Gas Company, on the Cost of Capital for Natural Gas Transmission Assets, June 2008 and August 2009.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER08-1207-000, on behalf of Virginia Electric and Power Company, on the incentive Cost of Capital for investment in New Electric Transmission Assets, June 2008
Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER08-1233-000, on behalf of Public Service Electric and Gas Company, on the Cost of Capital for Electric Transmission Assets, July 2008.

Direct and rebuttal testimony before the Public Service Commission of West Virginia, Case No. 08-0900-W-42t, on behalf of West Virginia-American Water Company concerning the Cost of Capital for Water Utility assets, July 2008 and November 2008.

Direct and rebuttal testimony before the Public Utilities Commission of Ohio, Case No. 08-935-EL-SSO, on behalf of Ohio Edison Company, The Toledo Edison Company, and The Cleveland Electric Illuminating Company, with regard to the test to determine Significantly Excessive Earnings within the context of Senate Bill No. 221, September 2008 and October 2008.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER09-249-000, on behalf of Public Service Electric and Gas Company, on the incentive Cost of Capital for Mid-Atlantic Power Pathway Electric Transmission Assets, November 2008.

Direct and rebuttal testimony before the Public Service Commission of West Virginia, Case No. 08-1783-G-PC, on behalf of Dominion Hope Gas Company concerning the Cost of Capital for Gas Local Distribution Company assets, November 2008 and May 2009.

Written Evidence before the Alberta Utilities Commission in the matter of the Alberta Utilities Commission Act, S.A. 2007, c. A-37.2, as amended, and the regulations made thereunder; and IN THE MATTER OF the Gas Utilities Act, R.S.A. 2000, c. G-5, as amended, and the regulations made thereunder; and IN THE MATTER OF the Public Utilities Act, R.S.A. 2000, c. P-45, as amended, and the regulations made thereunder; and IN THE MATTER OF Alberta Utilities Commission 2009 Generic Cost of Capital Hearing, Application No. 1578571/Proceeding No. 85. 2009 Generic Cost of Capital Proceeding on behalf of NGTL, November 2008.

Written and Reply Evidence before the Alberta Utilities Commission in the matter of the Alberta Utilities Commission Act, S.A. 2007, c. A-37.2, as amended, and the regulations made thereunder; and IN THE MATTER OF the Gas Utilities Act, R.S.A. 2000, c. G-5, as amended, and the regulations made thereunder; and IN THE MATTER OF the Public Utilities Act, R.S.A. 2000, c. P-45, as amended, and the regulations made thereunder; and IN THE MATTER OF Alberta Utilities Commission 2009 Generic Cost of Capital Hearing, Application No. 1578571/Proceeding No. 85. 2009 Generic Cost of Capital Proceeding on behalf of AltaGas Utilities Inc., November 2008 and May 2009.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER09-548-000, on behalf of ITC Great Plains, LLC, on the Cost of Capital for Electric Transmission Assets, January 2009.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER09-681-000, on behalf of Green Power Express, LLP, on the Cost of Capital for Electric Transmission Assets, February 2009.
Written evidence before the Régie de l'Énergie on behalf of Gaz Métro Limited Partnership, Cause Tarifaire 2010, R-3690-2009, on the Cost of Capital for natural gas transmission assets, May 2009.

Direct and rebuttal testimony before the Public Service Commission of Wisconsin, Docket No. 6680-UR-117, on behalf of Wisconsin Power and Light Company, on the cost of capital for electric and natural gas distribution assets, May 2009 and September 2009.

Direct and rebuttal testimony before the State of New Jersey Board of Public Utilities in the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 14 Electric and B.P.U.N.J No. 14 Gas Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and for Approval of a Gas Weather Normalization Clause; a Pension Expense Tracker and for other Appropriate Relief BPU Docket No. GR09050422, June 2009 and December 2009.

Rebuttal testimony before the Florida Public Service Commission in re: Petition for Increase in Rates by Progress Energy Florida, Inc., Docket No. 090079-EI, August 2009.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER10-159-000, on behalf of Public Service Electric and Gas Company, on the incentive Cost of Capital for the Branchburg-Roseland-Hudson 500 kV Line electric transmission project ("BRH Project"), October 2009.

Direct and Rebuttal Testimony before the California Public Utilities Commission regarding cost of service for San Joaquin Valley crude oil pipeline on behalf of Chevron Products Company, Docket Nos. A.08-09-024, C.08-03-021, C.09-02-007 and C.09-03-027, December 2009 and April 2010.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER10-516-000, on behalf of South Caroline Gas and Electric Company, on the Cost of Capital for Electric Transmission Assets, December 2009.

Direct testimony before the Oklahoma Corporation Commission, Cause No. PUD 201000050, on behalf of Public Service Company of Oklahoma, regarding cost of service for a regulated electric utility, June 2010.

Direct testimony before the Michigan Public Service Commission, Case No. U-16400, on behalf of Michigan Consolidated Gas Company, regarding cost of service for natural gas distribution assets, July 15, 2010

Direct testimony before the Public Utilities Commission of Ohio, Case No. 10-1265-EL-UNC, In the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2009 Under the Electric Security Plan of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, September 2010.

Direct and rebuttal testimony before the Federal Energy Regulatory Commission, Docket No. RP10-1398-000, on behalf of El Paso Natural Gas Company, on the Cost of Capital for Natural Gas Transmission Assets, September 2010 and September 2011.

Direct and rebuttal testimony before the Michigan Public Service Commission, In the matter of the application of The Detroit Edison Company, for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority, Case No. U-16472, October 2010 and April 2011.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. RP11-1566-000, on behalf Tennessee Gas Pipeline Company, on the Cost of Capital for Natural Gas Transmission Assets, November 2010.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER11-013-000, on behalf of the Atlantic Wind Connection Companies, on the Cost of Capital and Cost of Capital incentive adders for Electric Transmission Assets, December 2010.

Direct and rebuttal testimony before the Public Utilities Commission of the State of California, Docket No. A.11-05-001, on behalf of California Water Service Company, on the Cost of Capital for Water Distribution Assets, April 2011 and September 2011.

Rebuttal testimony before the Public Utilities Commission of the State of California, Docket No. A.10-09-018, on behalf of California American Water Company, on Application of California American Water Company (U210W) for Authorization to Implement the Carmel River Reroute and San Clemente Dam Removal Project and to Recover the Costs Associated with the Project in Rates, June 2011.

Initial testimony before the Public Utilities Commission of Ohio, Case No. 11-4553-EL-UNC, In the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2010 Under the Electric Security Plan of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, July 2011.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. PA10-13-000, on behalf of ITC Holdings Corp. in response to FERC Staff, Office of Enforcement, Division of Audits, Draft Report on the appropriate accounting for goodwill for the acquisition of ITC Midwest assets from Interstate Power and Light Company, July 2011.

Written direct and reply evidence before the National Energy Board in the matter of the National Energy Board Act, R.S.C. 1985, c. N−7, as amended, and the Regulations made thereunder; and in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part I and Part IV of the *National Energy Board Act*, for determining the overall fair return on capital in the business and services restructuring and Mainline 2012 – 2013 toll application, RH-003-2011, September 2011 and May 2012.

Report before the Arbitrator on behalf of Canadian National Railway Company in the matter of a Submission by Tolko Marketing and Sales LTD for Final Offer Arbitration of the Freight Rates and Conditions Associated with Respect to the Movement of Lumber by Canadian National Railway Company from High Level, Alberta to Various Destinations in the Vancouver, British Columbia Area, October, 2011.

Rebuttal Evidence before the National Energy Board in the matter of AltaGas Utilities Inc., 2010-2012 GRA Phase I, Application No. 1606694; Proceeding I.D. 904, October, 2011.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER12-296-000, on behalf of Public Service Electric and Gas Company on the Cost of Capital and for Incentive Rate Treatment for the Northeast Grid Reliability Transmission Project, October 2011.

Rebuttal testimony before the Florida Public Service Commission, Docket No. 110138-EL, on behalf of Gulf Power, a Southern Company, on the method to adjust the return on equity for differences in financial risk, November 2011.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. PA10-13-000, on behalf of ITC Holdings Corp. regarding a rehearing for FERC Staff, Office of Enforcement, Division of Audits, Report on the appropriate accounting for goodwill for the acquisition of ITC Midwest assets from Interstate Power and Light Company, February 2012.

Direct and rebuttal testimony before the Michigan Public Service Commission, Case No. U-16999, on behalf of Michigan Consolidated Gas Company, regarding cost of service for natural gas distribution assets, April 2012 and October 2012.

Deposition testimony in *Primex Farms, LLC, Plaintiff, v. Roll International Corporation, Westside Mutual Water Company, LLC, Paramount Farming Company, LLC, Defendants*, April 2012.

Deposition testimony in *Tahoe City Public Utility District, Plaintiff vs. Case No. SCV 27283 Tahoe Park Water Company, Lake Forest Water Company, Defendants*, May 2012.

Direct testimony before the Public Utilities Commission of Ohio, In the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2011 Under the Electric Security Plan of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, Case No. 12-1544-EL-UNC, May 2012.

Joint Rebuttal Testimony before the California Public Utility Commission on behalf of California American Water Company, regarding Application of California-American Water Company (U210W) for Authorization to increase its Revenues for Water Service, Application 10-07-007, and In the Matter of the Application of California-American Water Company (U210W) for an Order Authorizing and Imposing a Moratorium on New Water Service Connections in its Larkfield District, Application 11-09-016, August 2012.

Direct testimony and supporting exhibits on behalf of Transcontinental Gas Pipeline Company, LLC, before the Federal Energy Regulatory Commission, on the Cost of Capital for Interstate Natural Gas Pipeline assets, Docket No. RP12-993-000, August 2012.
Direct Testimony before the North Carolina Utilities Commission on behalf of Cardinal Pipeline Company LLC, regarding the cost of capital for an intrastate natural gas pipeline, Docket G-39, Sub 28, August 2012.

Rebuttal Testimony before the Public Utilities Commission of the State of California on behalf of Southern California Edison regarding Application 12-04-015 of Southern California Edison Company (U 338-E) For Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2013 and to Reset the Annual Cost of Capital Adjustment Mechanism , August 2012.

Direct and Rebuttal testimony before the Public Utilities Commission of the State of Colorado on behalf of Rocky Mountain Natural Gas LLC regarding the cost of capital for an intrastate natural gas pipeline, Docket No. 13AL-143G, with Advice Letter No. 77, January 2013 and October 2013.

Expert Report, with A. Lawrence Kolbe and Bente Villadsen, on cost of equity, non-recovery of operating cost and asset retirement obligations on behalf of the AOSPL oil pipeline in arbitration in the matter of the 1993 AOSPL Pipeline Agreement between: Canadian Oil Sands Partnership #1, Imperial Oil Resources, Suncor Energy Oil & Gas Partnership, Sinopec Oil Sands Partnership, Nexen Oil Sands Partnership, Mocal Energy Limited and Murphy Oil Company Ltd- and - Alberta Oil Sands Pipeline Ltd. in its capacity as General Partner of Pembina Oil Sands Pipeline L.P., April 2013.

Direct testimony before the Public Utilities Commission of Ohio in the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2012 Under the Electric Security Plans of Ohio on behalf of the Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, Case No. 13-1147-EL-UNC, May 2013.

Presentation on behalf of Alabama Power Company with regard to the appropriate cost of capital for the Rate Stabilization and Equalization mechanism, Dockets 18117 and 18416, July 2013.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER13-2412-000, on behalf of Trans Bay Cable LLC, regarding the appropriate ROE to include in the Submission of Revisions to Appendix I of the Trans Bay Transmission Owner Tariff to be Effective 11/23/2013, September 2013.

Direct testimony, rebuttal testimony and sur-surrebuttal testimony before the Arkansas Public Service Commission regarding the appropriate ROE to allow In the Matter of the Application of SourceGas Arkansas Inc., Docket No. 13-079-U for Approval of a General Change in Rates, and Tariffs, September 2013, March 2014, and April 2014.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER14-1332-000, on behalf of DATC Path 15, LLC, regarding the appropriate ROE to include in the

Submission of Revisions to Appendix I in TO Tariff Reflecting Updated TRR to be Effective April 20, 2014, January 2014.

Direct testimony before the Public Utilities Commission of Ohio in the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2012 Under the Electric Security Plans of Ohio on behalf of the Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, Case No. 14-0828-EL-UNC, May 2014.

Direct testimony before the Public Service Commission of West Virginia in the Matter of the Application of Monongahela Power Company and The Potomac Edison Company, Case No. 14-0702-E-42T for approval of a general change in rates and tariffs, June 2014.