Gregory and Donna Kollmar, v. West Penn Power Company Further Call-In Telephonic Hearing	Docket No.: C-2019-3014650

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Judge's Chambers

Piatt Place

301 5th Avenue

Suite 220

Pittsburgh, PA

Monday, May 12, 2025

Commencing at 1:00 p.m.

INDEX TO EXHIBITS

Docket No. C-2019-3014650

Hearing Date: May 12, 2025

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April 23, 2025

VIA ELECTRONIC MAIL DELIVERY

Administrative Law Judge Emily DeVoe
Pennsylvania Public Utility Commission
Office of the Administrative Law Judge
edevoe@pa.gov

Re: Gregory and Donna Kollmar v. West Penn Power Company
Docket No. C-2019-3014650

Dear Judge DeVoe:

An evidentiary hearing has been scheduled for Wednesday, April 30, 2025, at 10:00 a.m. I have enclosed copies of the proposed exhibits which FirstEnergy Pennsylvania Electric Company ("the Company") intends to present at the hearing regarding the above-referenced matter on behalf of its West Penn Rate District.

The proposed exhibits have been served on the Complainants as shown in the Certificate of Service.

Please contact me if you have any questions.

Respectfully submitted,

James Austin Meehan

James Austin Meehan

JAM/krak
Enclosures

c: Secretary Matthew Homsher (Cover letter and Certificate of Service only via e-filing)
As Per Certificate of Service

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

GREGORY AND DONNA KOLLMAR	:	
	:	**Docket No. C-2019-3014650**
v.	:	
	:	
WEST PENN POWER COMPANY	:	

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true copy of the proposed exhibits of FirstEnergy Pennsylvania Electric Company on behalf of its West Penn Rate District upon the individuals listed below, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

Service by overnight mail and electronic mail as follows:

Donna and Gregory Kollmar
dlkollmar77@gmail.com

Administrative Law Judge Emily DeVoe
edevoe@pa.gov

Dated: April 23, 2025

James Austin Meehan

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

GREGORY AND DONNA KOLLMAR	**:**	
	:	**Docket No. C-2019-3014650**
v.	**:**	
	:	
WEST PENN POWER COMPANY	**:**	

PROPOSED EXHIBITS OF
FIRSTENERGY PENNSYLVANIA ELECTRIC COMPANY

Exhibits

FE PA-1: Smart Meter Deployment Plan

FE PA-2: Customer Contacts.

Public Documents

PD-1: 66 Pa.C.S. § 2807.

PD-2: Smart Meter Procurement and Installation, Docket No. M-2009-2092655 (Order entered June 24, 2009).

PD-3: Petition of West Penn Power Company d/b/a Allegheny Power for Expedited of its Smart Meter Technology Procurement and Installation Plan Docket No. 2009-2123951 (Order entered June 30, 2011).

PD-4: 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-

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

METROPOLITAN EDISON COMPANY
DOCKET NO. M-2013-2341990

PENNSYLVANIA ELECTRIC COMPANY
DOCKET NO. M-2013-2341994

PENNSYLVANIA POWER COMPANY
DOCKET NO. M-2013-2341993

WEST PENN POWER COMPANY
DOCKET NO. M-2013-2341991

SMART METER DEPLOYMENT PLAN

ORIGINAL DECEMBER 31, 2012
REVISED MARCH 19, 2014
REVISED JUNE 16, 2014

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CHAPTER 1. EXECUTIVE SUMMARY

1.1 Overview

1.1.1 History

On October 15, 2008, former Governor Edward G. Rendell signed House Bill 2200 into law as Act 129 of 2008 ("Act 129"). Among other things, Act 129 directed each electric distribution company ("EDC") with more than 100,000 customers to file a Smart Meter Technology Procurement and Implementation Plan ("SMIP") with the Pennsylvania Public Utility Commission ("Commission") by August 14, 2009. On June 24, 2009, the Commission entered an Implementation Order in which it provided general guidance as to the information to be included in the SMIP. On August 14, 2009, Metropolitan Edison Company ("Met Ed"), Pennsylvania Electric Company ("Penelec"), and Pennsylvania Power Company ("Penn Power") (collectively "PA Companies") submitted their SMIP, which was approved with minor modifications in an Order entered on June 9, 2010 ("SMIP Order"). As part of their SMIP, the PA Companies presented both a short term and long term plan, indicating that they would use the first 24 months of the 30-month Grace Period provided for by the Commission in its Implementation Order (the "Assessment Period") to assess their needs, select the necessary technology, secure vendors, train personnel, install and test support equipment, and establish a detailed meter deployment schedule consistent with the statutory requirements.[1] The PA Companies indicated that at the end of the Assessment Period they would submit to the Commission a Smart Meter Deployment Plan that included: (i) a detailed long term timeline, with key milestones; (ii) a smart meter solution; (iii) the estimated costs of such a solution, along with an assessment of benefits; (iv) a network design solution; (v) a communications architecture design solution; (vi) a training assessment and proposed curriculum; (vii) a cost recovery forecast; (viii) a transition plan including communications plan for employees and consumers; and (ix) a detailed, tiered roll-out plan.[2]

Subsequent to the filing of the PA Companies' SMIP, FirstEnergy Corp. ("FirstEnergy"), the PA Companies' parent company, announced its intent to merge with Allegheny Energy Inc. ("Allegheny"). Allegheny owned West Penn Power ("West Penn") which submitted its own smart meter implementation plan to the Commission on August 14, 2009 in Docket No. M-2009-2123951 ("WPP SMIP"). Subsequent to making its filing, West Penn and interested parties, entered

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[1] SMIP Order at 13-14.

[2] SMIP Order at 6-7. Upon receiving the SMIP Order, the PA Companies commenced their Assessment Period which, based upon the PA Companies' representations, would make their Deployment Plan due in June 2012.

into an Amended Joint Petition for Settlement ("Joint Settlement") in which West Penn made several commitments that significantly changed its original SMIP filing. Among them was a commitment to decelerate its proposed deployment of smart meters and to submit a Revised SMIP (which is the equivalent of the PA Companies' Deployment Plan) no sooner than June 30, 2012.[3] The Commission approved the Joint Settlement on June 30, 2011 ("WPP Order").

Upon completion of the merger between FirstEnergy and Allegheny, and approval of the Joint Settlement, the smart meter needs of West Penn, along with West Penn's commitments made through the Joint Settlement, were incorporated into the analyses and other work being done by the PA Companies' Smart Meter Implementation Plan team ("SMIP Team") – a core team comprised of employees of the PA Companies (supplemented by Allegheny employees post merger), representing a variety of interests and skill sets, subject matter experts from the consulting firms of IBM, Inc. ("IBM") and Black & Veatch Corp. ("Black & Veatch"), and various technology vendor representatives knowledgeable in areas involving key components and process designs of the core smart meter infrastructure solution. Work performed by West Penn when preparing the WPP SMIP was incorporated into the overall development of this Deployment Plan, thus reducing the amount of work that otherwise would have been necessary to complete such development.

While the SMIP Team was in the process of finalizing the Deployment Plan for filing in June 2012, several smart meter vendor finalists independently indicated their intent to release improved smart meter system technology in the late spring of 2012. It was expected that this improved technology would provide enhanced two-way communication capability and flexibility throughout the footprint of the PA Companies and West Penn (together, the "Companies"), and would provide expanded interface capabilities with potential Smart Grid applications in the future. Because of its imminent release, the SMIP Team felt compelled to assess the improved technology before making its final smart meter recommendations. Therefore, in June 2012, the Companies requested and received an extension of their Assessment Period through December 31, 2012 -- the end of the PA Companies' Grace Period -- so that the team could test this then soon-to-be-released technology in order to determine if (i) it properly interfaced with other smart meter infrastructure equipment being considered; and (ii) it indeed had the improvements promised by the vendors. Testing of this improved technology occurred during the second half of 2012 and the results were assessed as part of the technology selection process, which is more fully discussed in Chapter 2.

[3] For a complete list of the commitments made by West Penn, see West Penn's 2011 SMIP Status Report, filed with the Commission on August 31, 2011 in Docket No. M-2009-2123951.

In the interim between the completion of the evidentiary hearing in May 2013 and the release of the Administrative Law Judge's Recommended Decision in November 2013, the Companies continued testing the selected end-to-end smart meter solution. Based upon these test results the Companies believe that it is now possible to accelerate the deployment of Smart Meters beyond that originally proposed in the deployment plan ("Original Deployment Plan" or "Deployment Plan"). This Deployment Plan has been revised to reflect this accelerated schedule ("Revised Deployment Plan").

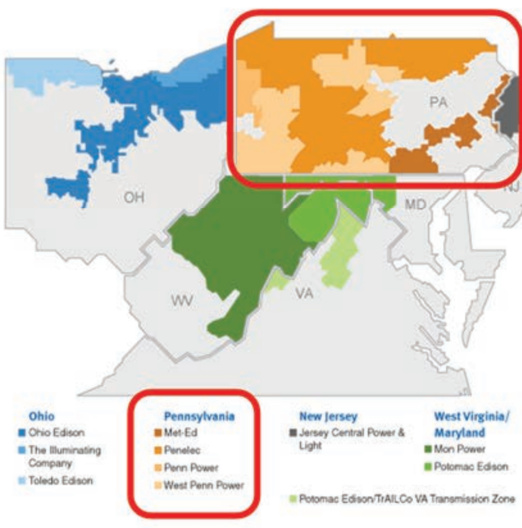
This Revised Deployment Plan is based upon the most current available information and sets forth a plan that will accelerate the installation of smart meters, with all of Penn Power's customers receiving smart meters by the end of 2015, and approximately 98.5 percent of all customers within the FirstEnergy Pennsylvania footprint receiving smart meters no later than mid-2019, with the remaining remote customers receiving meters no later than 2022. The projected cost of this Revised Deployment Plan is still approximately $1.258 billion over a 20 year life cycle of the project on a nominal dollar basis, and approximately $608 million on a net present value ("NPV") basis after netting estimated potential operational cost savings of approximately $142 million (NPV). Approximately $815 million (nominal) will be spent during the six year construction and meter deployment period that is expected to start on July 1, 2014 and conclude prior to the end of 2019 ("Deployment Period"), assuming the Commission approves this Plan by June 30, 2014.

Chapter 2 explains in more detail the work performed to develop the Original and Revised Deployment Plans. Chapter 3 describes the recommended solution and its compliance with Act 129 and Commission directives. Chapter 4 addresses the cost of implementing the Revised Deployment Plan, the estimated savings that the Companies and their customers may realize during the 20 year life of the plan and how these savings will be tracked. Chapter 5 addresses cost recovery issues and how the amounts to be included in each of the Companies' respective Commission-approved riders will be calculated. It also sets forth the estimated bill impacts for the various customer classes within each of the Companies and addresses several other rate and regulatory issues. Finally, Chapter 6 discusses the other deliverables promised in the PA Companies' SMIP and the West Penn Joint Stipulation.

1.2 About the Companies

Met-Ed, Penelec, Penn Power and West Penn are wholly-owned subsidiaries of FirstEnergy Corp., and make up the FirstEnergy Pennsylvania footprint.[4] With its ten electric utility operating companies, FirstEnergy operates one of the largest investor-owned electric utilities in the United States, serving approximately 6 million customers over an approximately 65,000 square-mile service territory within Ohio, Pennsylvania, New Jersey, Maryland and West Virginia.

Figure 1.1 FirstEnergy Pennsylvania Service Territories



Customer Class	Projected Average Customer Class Count For the Twelve Months Ending December 31, 2013			
	Met-Ed	Penelec	Penn Power	West Penn
Residential	489,495	501,138	140,393	619,826
Commercial	65,082	81,078	18,987	93,309
Industrial	832	866	151	2,744
Total	555,409	583,583	159,531	715,879

3

1.2.1 Size and Nature of Each Territory

Below is a brief description of each of the Companies' service territories.

Metropolitan Edison

Met-Ed is a wholly-owned subsidiary of FirstEnergy. It serves approximately 555,000 electric utility customers over 3,570 square miles in southern and southeastern Pennsylvania. Approximately 88% of its customers are residential customers and about 12% are commercial and industrial customers. Meter densities are as follows: 3% with 10 end points or fewer per square mile; 50.1%

[4] West Penn is a subsidiary of Allegheny Energy Inc., which, along with the PA Companies and other entities, is a first tier subsidiary of FirstEnergy.

with 11-100 end points per square mile; 27.2% with 101-200 end points per square mile; and 19.7% with more than 200 end points per square mile.

Penelec

Penelec is a wholly-owned subsidiary of FirstEnergy. It serves approximately 584,000 customers over approximately 17,600 square miles in northern, northwest, and central Pennsylvania. Approximately 86% of its customers are residential customers and about 14% are commercial and industrial customers Meter densities are as follows: 15% with 10 end points or fewer per square mile; 45.4% with 11-100 end points per square mile; 25.5% with 101-200 end points per square mile; and 14.1% with greater than 200 end points per square mile.

West Penn Power

West Penn is a wholly-owned subsidiary of Allegheny, which is a wholly-owned subsidiary of FirstEnergy. It serves almost 716,000 customers over approximately 10,300 square miles in southwest, north central, and south central Pennsylvania. Approximately 86% of its customers are residential customers and about 14% are commercial and industrial customers. Meter densities are as follows: 2% with 10 end points or fewer per square mile; 44% with 11-100 end points per square mile; 41% with 101-200 end points per square mile; and 13% with greater than 200 end points per square mile.

Penn Power

Penn Power is a wholly-owned subsidiary of Ohio Edison that is, in turn, a wholly-owned subsidiary of FirstEnergy. Penn Power serves about 160,000 customers over approximately 1,100 square miles in western Pennsylvania. Approximately 88% of its customers are residential customers and about 12% are commercial and industrial customers. Meter densities are as follows: 8.9% with 10 end points or fewer per square mile; 55.3% with 11-100 end points per square mile; 27.7% with 101-200 end points per square mile; and 8.1% with greater than 200 end points per square mile.

The overall diversity of the Companies' service territory terrain creates significant challenges specific to the Companies. Additional challenges, not unique to the Companies, include the need to develop a deployment plan in an environment that continues to change as technology improves, vendors merge, and standards and guidelines are established on a regional and national level. These and many other factors were considered when designing the smart meter solution included in this Deployment Plan.

1.3 Objectives and Assumptions

1.3.1 Objectives

The objectives surrounding the development of this Deployment Plan were as follows:

1. Submit a plan that complies with Act 129, the Implementation Order, and the various commitments made by any of the Companies.

2. Minimize the likelihood of stranded investment through obsolescence by performing robust evaluation and analysis and adhering to evolving national smart metering guidelines and policies.

3. Present a plan that provides the Companies with full cost recovery, including fair returns for any capital employed, while allowing them sufficient financial flexibility to provide for their other not-insubstantial capital requirements and obligations to shareholders.

4. Develop a strategic and cost effective deployment plan that will maximize early benefits taking into account risk and related costs.

5. Develop a workable process to track, measure and verify benefits arising from the implementation of this Deployment Plan.

1.3.2 Assumptions:

The development of this Deployment Plan was based on the following assumptions:

1. Act 129 calls for 100% customer deployment of smart meters with an implementation timeline of up to 15 years from the date of approval of the SMIP Plan. There will be no opt-out for customers.

2. Time-of-Use (“TOU”) and Real-Time-Pricing (“RTP”) rates will be in place consistent with Pennsylvania law and the Commission’s Implementation Order.

3. Full and timely cost recovery of all costs associated with the evaluation, development, deployment and operation of a smart metering system will be approved.

4. After their grace period, the Companies will install smart meters in all new construction and upon customer request, provided that the latter pays for the incremental cost of such meters and related installation.

5. None of the functionality provided through a smart meter installed in new construction will be available until the infrastructure needed for two-way communication is built in the area.

6. The smart meter solution is designed to integrate with legacy systems such as SAP to the practical degree possible.

7. All smart meters must be working no later than 2025.

1.4 The Deployment Plan Development

Upon approval of the PA Companies' SMIP, the SMIP Team commenced work on this Deployment Plan. The team was subdivided into nine substantive subgroups, or workstreams: (i) Solution Framework; (ii) Current State; (iii) Vendor Strategy; (iv) Technology Evaluation and Test Lab; (v) Future State; (vi) Network Communications; (vii) External Communications and Consumer Awareness Strategies; (viii) Change Management and Training; and (ix) a Project Management Office. The PA Companies included in their Status Report filed with the Commission on July 27, 2011 at Docket No. M-2009-2123950 an outline of the major tasks and timelines during which each of the tasks for each of the workstreams was to be performed.

During the Assessment Period, the SMIP team reviewed numerous documents, including the PA Companies' SMIP, the Commission's Implementation Order, the Pa Companies' SMIP Order, Act 129, and the West Penn Joint Settlement documents and related Commission Orders, so as to ensure that this Deployment Plan complies with Act 129, Commission directives, and all of the commitments made by any of the Companies. The SMIP Team also held stakeholder meetings, including several with those interested in data access and sub-hourly metering, and others with parties interested in low income and other vulnerable customer issues. The SMIP Team held discussions with employees and management of the Companies from all affected business groups, and with employees of other Pennsylvania EDCs who were responsible for those EDCs' smart meter projects. They participated in several utility site visits both within and outside of Pennsylvania, and held numerous discussions with out-of-state utilities that have smart meter programs in various forms and stages. The team sought Requests for Information ("RFIs") from major system and equipment vendors and then Requests for Proposals ("RFPs") from vendors resulting from the RFIs and subsequent testing. Details surrounding both the development of this Deployment Plan and the vendor selection process are set forth in Chapter 2. During the period between the filing of the Original Deployment Plan and the issuance of the Administrative Law Judge's Recommended Decision, the Companies continued testing the selected end-to-end solution. Based upon the results of this testing, the Companies now believe that, absent unforeseen events, the deployment schedule as originally proposed ("Original Deployment Schedule"), can be modified to (i) build out the entire Penn Power end-to-end solution, instead of only installing 60,000 meters; and (ii) accelerate the completion of the Solution Validation Stage and the commencement of the Full-Scale Deployment Stage by one year ("Accelerated Deployment Schedule"). This schedule is further summarized in Section 1.6.

1.5 The Recommended Solution

The recommended solution includes the following major components:

Smart meters – The meters collect, store, and transmit total consumption data, interval data, and meter events to core applications after configuration, and communicate with Home Area Networks (HANs).

Meter Data Management System (MDMS) – The meter data management system provides for storage of meter data from smart meters, including interval meter reads, and processes raw meter data with Validate, Edit and Estimate ("VEE") algorithms for utilization in corporate systems, such as billing and customer service. An MDMS may be integrated with utility billing and customer care software (such as SAP's solution for utilities which is used by the PA Companies).

Head End/collection engine – The Head End/collection software collects and delivers information from the meters via the collectors to the MDMS. A proprietary local area network ("LAN") is often used for communications between the meters and the collectors.

"Backhaul" communications network (external) – This network (typically a "wide area network") is the communication system between the collectors and the Head End and includes data center equipment and control software.

Home Area Network ("HAN") – The HAN is a network contained within a user's home that communicates information to in-home devices (IHDs) such as in-home displays.

A more detailed discussion of the recommended solution can be found in Chapter 3.

1.6 The Deployment Schedule and Functionality

The Companies are recommending a phased deployment strategy which anticipates three distinct stages: (i) the Post Grace Period ("PGP") Stage; (ii) the Solution Validation Stage; and (iii) the Full-Scale Deployment Stage.

The PGP Stage, which commences on January 1, 2013 and concludes with the completion of deployment, currently scheduled by December 31, 2022, addresses not only the need to provide smart meters for all new service requests received on or after January 1, 2013 ("New Construction") and for all customers requesting a smart meter prior to their scheduled installation date ("Early Adopters"), but also addresses contract negotiations, final RFPs and other pre-deployment activities.

New Construction/Early Adopters: For new construction for which a temporary or permanent service application is received on or after January 1, 2013, the customer will be provided with a RF smart meter included in the recommended technology solution, which will eventually be able to communicate with the smart meter network infrastructure. Customers will not be billed additional fees for the meter or other installation costs beyond those charged to all metered customers through the Smart Meter Technologies Charge Rider. During the period between smart meter installation and the build-out of the smart meter network in the area where a New Construction smart meter installation occurs, neither the communication functions of the meter nor smart meter functionality will be available and meter reads will be done manually using existing meter reading and billing procedures.

For Early Adopters, once the customer pays the incremental costs for the meter and related installation,[5] a Point-To-Point ("PTP") smart meter that meets the basic Act 129 functionality requirements will be installed. This smart meter will communicate via a public cellular network and will provide on-line access to validated meter data within 24-48 hours and access to unvalidated meter data via a direct access interface to a device that is part of the Home Area Network.[6] Meter reads for billing purposes will continue to be done manually using existing meter reading and billing procedures until the smart meter network infrastructure becomes available at the customer's location and the PTP meter is replaced with the smart meter selected as part of the smart meter technological solution.

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[5] Tariff provisions implementing the Companies' proposals for Early Adopters were filed with the Commission on October 31, 2012 and approved on December 21, 2012. *See* Docket Nos. R-2012-2332803; R-2012-2332776; R-2012-2332785; R-2012-2332790.

[6] In the event public cellular coverage is unavailable for a requesting customer, the Companies will investigate alternative solutions on a case-by-case basis.

Contract Negotiation/RFPs: During the period between the filing of the Original Deployment Plan with the Commission on December 31, 2012 and the submission of this Revised Deployment Plan, the SMIP Team selected a Systems Integrator ("SI") and Project Management Office ("PMO") consultant through the RFP process described in Chapter 2, and negotiated final terms and conditions with all key vendors. Further the SMIP Team worked with consultants and selected vendors to develop construction schedules, all with the goal to have everything in place to start construction of the infrastructure upon approval of this Revised Deployment Plan.

The Solution Validation Stage incorporates two activities: the build-out of the infrastructure needed to install smart meters and a testing period in which a "Penn Power end-to-end version" of the Companies' comprehensive Pennsylvania end-to-end smart meter solution will be constructed and tested prior to full scale deployment. Specifically, this stage is expected to start in mid-2014 and continue until the end of 2015. Instead of installing 60,000 meters during this stage, as was originally contemplated, the Revised Deployment Plan anticipates the complete build out of Penn Power (approximately 170,000 smart meters and supporting end-to-end infrastructure) during this period.

- *Build-Out Activities*. This period begins upon Commission approval of this Revised Deployment Plan and will continue for approximately 18 months. During this period, the Companies will commence construction of the smart meter solution infrastructure, or "backbone" for the Penn Power "mini system". This will involve the installation of meters, collectors, range extenders, network communications, and meter data management systems for testing.

- *Solution Testing Activities*. As the infrastructure is built out, the Companies will install meters in Penn Power's service territory. This territory was selected because it includes the types of challenges the SMIP Team anticipates encountering during full deployment. Approximately 50,000 meters will be installed in 2014 and another 120,000 in 2015, in order to allow for the testing of scalability and the resolution of communication, functionality and installation problems encountered in a contained and controlled environment, thus minimizing costs of overall deployment and customer frustration. Only after all such problems are resolved will the Companies commence the final Full-Scale Deployment Stage, which is currently anticipated to commence in early 2016.

The Full-Scale Deployment Stage will commence upon resolution of all problems encountered during the Solution Validation Stage and will continue until all meters are installed on or before December 31, 2022. During this stage, the remainder of the smart meter infrastructure will be concurrently built in each of the Companies respective service territories, starting with the most populated areas first. All remaining smart meters will be installed during this Stage, initially at an average rate of 1,900 meters per day, five days per week, with the potential to accelerate deployment to as many as 3,000 meters per day, should circumstances and conditions warrant. At this pace, the Companies expect to install approximately 98.5% of all meters between January 1, 2016 and mid-2019, with the remaining 1.5% of the meters being installed thereafter through December 31, 2022[7]. This 1.5 % of the installations represent those installations that may require alternative communication solutions or difficult to reach locations such as remote hunting cabins. Any similar situations discovered in Penn Power's service territory are included in this estimate of 1.5% and will be addressed in the time frame discussed above.

While the meters upon installation will be *capable* of providing all meter functionality required by Act 129 and the Commission's Implementation Order, *actual* functionality will become available upon completion of the communication network in the area, currently expected to lag installation by approximately 3 months.

1.7 Financial Implications

The Companies' financial assessment is based on a 20 year life cycle and a financial model that was designed to estimate the costs of implementing the Original Deployment Plan as well as the potential verifiable savings that may be realized through the installation of smart meter technology. Thus, certain inputs have been modified to reflect the Accelerated Deployment Schedule, the results of which are set forth in this Revised Deployment Plan. There are potentially other benefits that may accrue directly to customers that have not been taken into account in this analysis. These customer benefits are addressed in Chapter 4.

[7] While the Companies originally anticipated an average installation rate of 3,000 meters per day, based upon subsequent discussions with meter installation vendors, it was recommended that installation be paced at 1,900 meter per day and ramped up over time if appropriate.

Below is a summary of both the estimated costs and estimated potential savings by Company in nominal dollars over the 20 year life of the project:

Figure 1.2 Estimated Costs and Potential Savings
($ Millions, Nominal, 20 Years)

	Total PA	Met-Ed	Penelec	Penn Power	WPP
Capital Costs	$ 667,390,350	$ 181,338,201	$ 192,354,386	$ 60,847,753	$ 232,850,010
O&M Costs	$ 590,204,938	$ 162,940,051	$ 172,612,059	$ 46,040,407	$ 208,612,421
Total Costs	$ 1,257,595,288	$ 344,278,252	$ 364,966,445	$ 106,888,160	$ 441,462,431
Total Savings	$ 417,023,753	$ 102,911,556	$ 124,772,459	$ 34,358,311	$ 154,981,427

Key assumptions and calculation drivers for each of the cost and operational savings components are discussed in detail in Chapter 4.

1.8 Cost Recovery and Bill Impacts

1.8.1 Cost Recovery

Like the Original Deployment Plan, costs associated with this Revised Deployment Plan will be recovered through existing Commission-approved SMT-C Riders. The SMT-C Riders contain SMT-C rates calculated separately for the residential, commercial, and industrial customer classes, and are expressed as a non-bypassable monthly customer charge to all metered customer accounts except for West Penn's residential customer class, which is billed on a dollar per kilowatt-hour basis. The SMT-C Riders are a reconcilable automatic adjustment clause under Section 1307 of the Pennsylvania Public Utility Code and recover capital and O&M costs and provide a return on capital investments.

Details on the cost recovery riders and other rate related issues are discussed in Chapter 5.

1.8.2 Estimated Customer Bill Impacts

Below is an estimate of monthly customer bill impacts by Company while the Revised Deployment Plan is in effect:

Figure 1.3 Monthly Bill Impacts (Nominal)[8]

Op Co	Residential		Commercial		Industrial	
	Range	Average	Range	Average	Range	Average
Met-Ed	$0.91 - $4.59	$2.36	$0.96 - $5.27	$2.89	$1.05 - $6.24	$3.52
Penn Power	$0.44 - $5.30	$2.56	$0.47 - $6.35	$3.09	$0.78 - $8.15	$4.13
Penelec	$0.76 - $4.50	$2.26	$0.76 - $4.50	$2.72	$0.95 - $6.10	$3.35
West Penn	$0.70 - $4.92	$2.64	$1.09 - $5.73	$3.27	$2.03 - $6.73	$4.30

Additional details are set forth in Chapter 5.

8 West Penn residential rates (indicated by an asterisk) are proposed on a kWh basis to be consistent with the West Penn June 30, 2011 Commission-approved Joint Petition for Settlement.

CHAPTER 2. DEPLOYMENT PLAN DEVELOPMENT

2.1 Overview

The PA Companies, later joined by West Penn, developed the Deployment Plan during the thirty month Grace Period following Commission approval of their SMIP in June 2010. In order to address the full scope of the Deployment Plan requirements, the PA Companies, in 2010, supplemented their then-existing SMIP team by adding more FirstEnergy employees (including some from West Penn post-merger) with a variety of skill sets, and additional subject matter experts from IBM, Black & Veatch and various technology vendor representatives knowledgeable in areas involving key components and process designs of smart meter infrastructure solutions ("SMIP Team").

The SMIP Team was subdivided into nine substantive subgroups, or workstreams:

(i) Solution Framework;

(ii) Current State;

(iii) Vendor Strategy;

(iv) Technology Evaluation and Test Lab;

(v) Future State;

(vi) Network Communications;

(vii) External Communications and Consumer Awareness Strategies;

(viii) Change Management and Training; and

(ix) Program Management Office ("PMO").

Each workstream was tasked with assessing the Companies' current state of smart meter infrastructure, technology "baselines" within the Companies, and available technologies and vendors. The workstream subgroups were then tasked with developing future state requirements for an initial design for a transition to smart meter technology by the Companies.

Upon completion of this assessment and initial design work, the Companies, with assistance from IBM consultants, developed a set of RFIs to a variety of vendors, which in turn led to RFPs from a shorter list of vendors identified through the RFI process. The various technologies offered by these vendors were tested both in the Companies' test labs and in the field to ensure that each piece of equipment selected would operate properly with the other infrastructure components and provide the functionality necessary to comply with Act 129 and Commission requirements. Following visits to utilities which had implemented the different vendor technologies, the SMIP team selected the smart meter infrastructure that is described in Chapter 3.

2.2 Selection of Consultants

In order to develop their SMIP, the PA Companies implemented a competitive procurement process in 2009-2010 for experienced consultants. Black and Veatch was selected through this process and assisted with the PA Companies' development of their SMIP. Subsequently, the Companies conducted a second procurement process and selected IBM (with Black & Veatch as a sub-partner) to design and implement the work plan for the Assessment Period and to develop this Deployment Plan as part of the SMIP Team. The decision to select IBM with Black & Veatch was based on their extensive experience in planning for and implementing smart metering projects for other utilities. In addition to IBM and Black & Veatch, the SMIP Team worked with SAP America, Inc. (SAP), Itron, Inc. (Itron), eMeter Corporation (eMeter), Sensus USA Inc. (Sensus), and Landis+Gyr Technology, Inc. (Landis+Gyr) in the Solution Framework.

Following the FirstEnergy-Allegheny merger in 2011, the scope of IBM's role expanded to support the assessment, analysis and integration of West Penn's smart meter needs into the Deployment Plan and to assist in the related analyses of costs and potential savings for all four of the Companies.

2.3 Assessment of Needs

2.3.1 Background

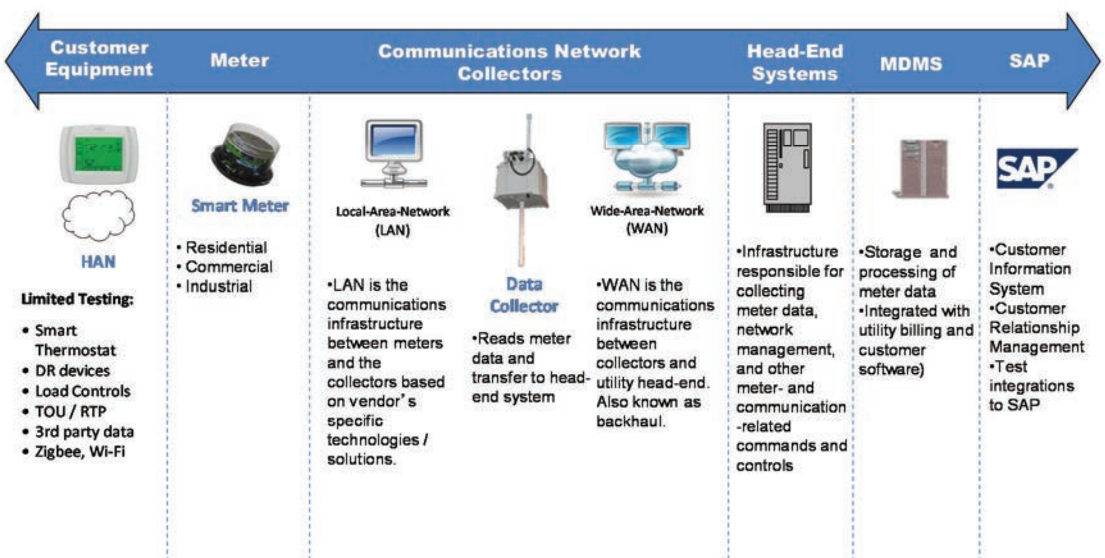
The integration of smart meters and supporting technologies is known as Advanced Metering Infrastructure ("AMI"). AMI enables bidirectional communication, records customer consumption hourly (or more frequently), and provides for transmittal of meter readings over a communication network to a central collection point and supporting commercial systems. As described in Chapter 1, the components of an AMI system typically include smart meters, a MDMS, a Head End/collection engine, and a backhaul communications network.

The technology needs assessment addressed each of these AMI components and vendors and equipment capable of supplying the functionality needed to meet the Commission's requirements. The outcome of this assessment was a solutions architecture that detailed the systems environment needed to install smart meters and the associated infrastructure. The architecture formed the basis of the vendor evaluation process and served as a key input to the financial analysis surrounding the recommended solution and this Deployment Plan.

The technology needs assessment was led by a team consisting of the Companies' IT professionals, representatives from business units and consultants from IBM. The consulting team brought specific knowledge, experience and a well-coordinated, planned approach gained from developing similar AMI solutions with other utilities across the United States and internationally. The team also defined a structured process for assessing requirements, identifying potential solutions, soliciting information from vendors, testing potential technologies in a lab and under field conditions and evaluating the costs and benefits of alternatives. In addition, both Current and Future State workshops were held, focusing on the technical implications of smart meters vis-à-vis the impacts on the Companies' business processes.

Figure 2.1 illustrates the interdependent chain of components considered in the smart meter solutions architecture, starting at the customer and ending with the Companies' billing and financial systems. Each of these components was addressed within the scope of the solutions architecture analysis and definition. Each component was also part of the end-to-end testing in both the test lab and in the field.

Figure 2.1 AMI High Level Scope Overview



2.3.2 Current State of Company Technologies

In order to evaluate the variety of possible smart meter solutions, the SMIP team undertook an extensive current state technology environment assessment focused on the Companies' existing IT applications and infrastructure that would be affected by smart metering, including metering and core applications for data gathering, processing, billing, reporting, and customer contact. The current state of both of these areas is summarized below.

Metering Environment

In Pennsylvania, the Companies serve approximately 2.0 million customers over approximately 33,000 square miles, primarily using manual meter reading along with a limited amount of interval meters. FieldNet is the Companies' system for manually reading meters. The Companies have approximately 4,000 interval meters in Pennsylvania that serve commercial and industrial ("C&I") customers.

The following table shows the breakdown of meters by operating company:

Figure 2.2 Meter Quantities and Types by Company

	Penn Power	Met-Ed	Penelec	WPP	Total
Residential	148,144	486,799	501,205	614,107	1,750,255
Commercial	20,356	64,712	82,081	92,414	259,563
Industrial	150	857	863	2,668	4,538
Public Street and Highway	86	671	860	558	2,175
Total Customers:	159,531	555,409	583,082	715,879	2,013,901
Total Meters:	168,650	552,368	584,149	709,189	2,014,356
***Total Square Miles:**	1,588	3,570	17,768	10,364	33,290
Meters/Square Mile:	106	154	33	70	61

* Total Number of Meters are higher than the Total Number of Customers since some customers have multiple meters

The service territories are unique, with diverse terrains that have varying degrees of customer density which distinguish them from other peer utilities. For example, the territories include both metropolitan and rural areas and terrains of mountains and valleys. In some instances, there are fewer than 10 meters per square mile and in other instances meters may be found underground or in block cement structures. Figure 2.3 shows the actual density distribution across the Companies' service territories:

Figure 2.3 Service Territory Definition and Meter Density Distribution

Category	Area	Meters
High ≥ 200 end points / square mile	0.4%	15.7%
Medium 101 < 200 end points / square mile	1.7%	26.5%
Low 11 < 100 end points / square mile	21.4%	48.6%
Very Low ≤ 10 end points / square mile	76.5%	9.2%
Total	100%	100%

West Penn's metering systems have been migrated to system platforms shared by the PA Companies. In accordance with its obligations under various settlements approved by the Commission, West Penn has an additional 25,000 smart meters already installed in its territory, which help it achieve its goals under its current Energy Efficiency and Conservation ("EE&C") Plan. These meters are manufactured by Itron and utilize a Smartsynch point-to-point solution, communicating data over a public cellular network. While these meters will be replaced as part of the Companies' smart meter solution, significant benefits accrued to the development of the Companies' selected solution as a result of West Penn's early smart meter deployment.

Core Applications

The Companies' core application processes that will be impacted by AMI are executed and managed by multiple systems and applications that fall into these major groups:

- Billing, Revenue, and Settlement Operations-Related Systems – These systems perform billing functions and provide data to various billing peripheral applications. The Companies utilize the SAP solution for billing and customer management. In addition, these systems provide settlement information to reconcile load and generation reporting to PJM, the Regional Transmission Organization ("RTO") for the Companies.

- Meter Data Collection Systems – These applications are tasked with collecting customer meter readings used for billing.

- Meter Management Systems – These applications primarily manage meter asset information including meter record creation, meter installation/removal, meter equipment specifications, and meter inventory tracking.

- Customer Contact Systems – These applications provide multiple contact points for customer communications and notifications. Applications include a web portal for C&I customers to view their interval data. Web presentment capabilities also include access to account and billing information, as well as a series of self-service transactions such as requests to move-in/move-out, upgrade service, report outages, and pay bills. Other capabilities include enrollment in budget billing and paperless billing, the ability to submit meter reads, and online access to education and safety information, the Companies' consumer product store, and a home energy analyzer allowing customers to receive personal energy profile information with graphs and downloadable data.

2.3.3 Assessment of Smart Meter and AMI Technologies

Smart metering and AMI technologies continue to evolve rapidly as utilities gain more experience, new requirements are identified, and technologies are tested under production conditions and improved upon. An unbiased review of the AMI/smart metering industry would best describe the industry as in its infancy, in flux and emerging. Of concern to the Companies is the constantly changing landscape of smart metering and AMI vendors. Financial stability, ability to meet production requirements, mergers and acquisitions, and intellectual property disputes were among the many types of vendor risks the Companies had to consider. These, as well as the following technical and vendor specific considerations, were factored into the AMI solution evaluation process.

Technical considerations include:

- Determining the correct technologies for the communications network best suited for a utility's service area topography and population
- Ensuring proper end-to-end bandwidth throughout the network, from HAN to back office
- Mitigating future risks by planning ahead to allow for flexibility
- Version management across multiple vendors and technologies, meter forms, program releases, Head Ends, MDMS, and corporate systems (e.g., SAP)
- Ensuring there is a prudent and defensible amount of testing for every version, release, and component
- Adhering to industry standards, including information security

Vendor-specific considerations include ensuring:

- Vendor's component functionality meets or exceeds identified business requirements
- Proper scale and performance testing by Vendor is conducted
- Vendor roadmaps align with the Companies' implementation plans
- Adequate management of technology upgrades
- Meter accuracy
- Deployment history/experience

The recommendations included in this Deployment Plan are dependent upon numerous vendors that will supply components (hardware, software, communications, services, system integration, and maintenance) of the solution. The vendor evaluation and procurement process, therefore, was crucial in selecting the right combination of vendors to meet the Companies' technical, functional, and business specifications. These activities drove the vendor and technology recommendations, based on validation in the test lab and field assessment.

Approach

The Companies have an extensive vendor selection process, managed and coordinated by FirstEnergy's procurement organization. In order to complement that process for this project, the Companies teamed with consultants from IBM who leveraged their experience with a number of AMI vendors and other utilities involved in various stages of smart meter deployment.

Through joint working sessions, an approach specific to AMI solutions was defined to methodically and deliberately move through the technology assessment, vendor evaluation and selection process. This approach ensured that key stakeholders within the Companies' business units were engaged in the selection process. The methodology and framework also ensured a disciplined, fair, and consistent vendor RFP and evaluation process that was fully documented.

The method undertaken for technology selection emphasized both tactical and strategic objectives and included:

- Ensuring that the ultimate AMI system meets tactical, strategic, and regulatory requirements
- Mitigating risk by allowing time for thorough testing and more informed decisions

- Ensuring on-going commercial flexibility and leverage until the full range of options is thoroughly explored, understood and evaluated
- Staging decisions so that they are made on a timely basis to meet overall project objectives, yet permitting additional critical information to flow into the decision process on the most critical decisions

The vendor evaluation process used an iterative process to evaluate and refine vendor options. This approach included the following components:

- Development of business, functional and technical requirements
- Identification of vendors and gathering data through an RFI process
- Assembly of a vendor short list
- Test lab and field assessment of technologies
- Execution of an RFP

Results and deliverables produced through this process were passed through gating reviews that involved detailed review, revision and approval by members of the SMIP Team.

Vendor Short List

The purpose of the Vendor Short List was to provide an assessment of the leading AMI solution vendors and meter manufacturers based on the experience of IBM and the knowledge of subject matter experts within the Companies. This team developed a Vendor Short List to determine those vendors that offered the most viable solutions for the Companies based on key priorities of this Deployment Plan. The priorities included:

- A range of technologies that could be considered for deployment as part of the Companies' smart meter solution
- Compatibility of vendor products with the Companies' overall solution architecture (including the ability to integrate with SAP)
- Commercial flexibility to use multiple vendors to support the Companies' smart meter program objectives

The Vendor Short List evaluated vendors for five components of the smart meter solution:

- Metering
- Head End
- Backhaul

- MDMS
- Meter Deployment

The AMI solution vendors and meter manufacturers were assessed using a comprehensive set of considerations, including:

- Functionality
- Technical features
- Network/communications
- Environment
- Security
- Alignment with the Companies' solution architecture
- Corporate stability and market presence
- Pricing

Business, functional and technical requirements were developed based on the results of a high-level requirements workshop with the Companies' leadership and IBM, followed by a series of requirement gathering workshops with the Companies' managers and subject matter experts. In addition to the internal work, IBM also reached out to other utilities across the country involved in AMI projects in order to determine if there were any evolving issues identified from their projects/experiences.

The requirements identified formed the basis for the development of the evaluation matrix and weighting criteria and were used in the development of the RFP. The following groups of requirements and specifications were defined:

- Mandatory smart meter requirements of Act 129:

    1. The ability to provide bidirectional data communications;

    2. The ability to record usage data on at least an hourly basis once per day;

    3. The ability to provide customers with direct access to and use of price and consumption information;

    4. The ability to provide customers with information on their hourly consumption;

5. The ability to enable Time-Of-Use ("TOU") rates and Real-Time Pricing ("RTP") program; and

6. The ability to support the automatic control of the customer's electric consumption.

- Additional functionality identified by the Commission in its Implementation Order for consideration, subject to deployment requirements:

1. The ability to remotely disconnect and reconnect;

2. The ability to provide 15 minute or shorter interval data to customers, EGSs, third parties and a regional transmission organization ("RTO") on a daily basis, consistent with the data availability, transfer and security standards adopted by the RTO;

3. On-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as ANSI C12.19 and C12.22 tables;

4. Open standards and protocols that comply with nationally recognized non-proprietary standards such as IEEE 802.15.4;

5. The ability to upgrade these minimum capabilities as technology advances and becomes economically feasible;

6. The ability to monitor voltage at each meter and report data in a manner that allows an electric utility to react to the information;

7. The ability to remotely reprogram the meter;

8. The ability to communicate outages and restorations; and

9. The ability to support net metering of customer generators.

- Additional suggested business requirements developed across different areas of the Companies (including Meter Reading, Meter Services, Revenue Operations, Billing, Rates, Customer Account Services, Customer Contact Center, T&D Planning, etc.) to support the above requirements. These requirements included:

1. Cyber security standards, internal security controls, physical environmental protections, etc.;

2. Additional functional specifications such as daily delivery of data, on-demand reads, outage flags, tamper flags, etc.;

3. Additional system specifications such as communications infrastructure, components specifications, storage, system accuracy, performance, etc.;

4. Implementation service requirements to support meter installation, configuration, reprogramming, etc.; and

5. Maintenance and support requirements, including testing and disaster recovery.

The Companies also identified the following requirements deemed essential for successful implementation:

- The functionality to integrate data from the meter to the Companies' SAP systems through the back-end system must be supported
- Multiple communication types (Head End to meter) over public network must be supported
- Multiple meter vendors must be supported by the AMI network
- The network must be robust in both high and low density environments

Using these requirements as the starting point, a business, functional and technical assessment was conducted to identify the requirements and specifications for smart meters.

The RFI Process

The SMIP Team issued its smart meter RFI in 2010, followed by RFPs in 2011. The RFI helped to establish/confirm information about the various vendors; provided more guidance during the development of the RFPs; provided input into the field assessment; and provided indicative pricing for use in the financial assessment of the smart meter solution and this Deployment Plan.

For the RFI, the business/technical requirements were developed with the understanding that the different product vendors would provide answers for the relevant deployment activity (i.e., meter vendors answer deployment/installation questions; Head End and MDMS vendors provide answers regarding software implementation). Requirements were also developed with the intent of supporting one RFI document, with vendors being given the option to propose one or more components in their response (e.g., meter, Head End, and/or MDMS).

The scope of the RFI was limited to the meters, Head End, and MDMS. RFI responses were evaluated using the following criteria:

- Act 129 requirements
- Commission Implementation Order requirements
- Extent of multiple communication offerings
- Robustness of communications network in all types of terrain environments
- Meter form support
- AMI solution security/privacy
- Solution maturity
- Solution scalability and performance
- Solution reliability
- Meter reliability
- Interoperability and open standards/compliance
- Corporate and financial stability
- Other North American deployments
- Solution pricing
- Support

MDMS systems were also required to be SAP-certified for integration with the Companies' SAP system used for billing and customer management.

Once RFI responses were received in Q1 2011, the team used a detailed evaluation plan and scoring template to assess results. RFI features were divided into two parts: those with objective responses and those with subjective responses. Preliminary testing of various vendors' technologies took place in the Companies' test labs. This was done to ensure that the various technologies performed as described by the vendors.

As a result of the RFI, a number of refinements and clarifications were made to the RFP before it was issued to vendors. The RFI also helped eliminate several vendors whose solutions did not align with the Companies' requirements or pass preliminary testing.

The RFP Process

The development of the RFPs occurred during Q2 & Q3 of 2011. Generally a format similar to that used for the RFI was employed to ensure that a high percentage of the content would be transferable. Although similar, there were several distinct differences between the RFI and the RFP processes, including:

- The single comprehensive RFI was broken out into five separate RFPs (adding backhaul deployment)
- Restated requirements (for clarity)
- Responses to clarifying questions raised during the RFI process were incorporated
- Performance requirements were incorporated
- Vendors were solicited for specific components, rather than allowing vendors to pick and choose on which of the components they desired to bid

RFP Requirements
Each of the five RFPs (smart meters, Head end system, MDMS, backhaul and meter deployment) required that the following information be provided:

- Concise description of overall experience/capabilities
- Detailed description of specific, by topic, experience/capabilities
- Identification of instances where subcontractors were used/leveraged to achieve success
- List of clients where similar efforts and/or solutions were performed
- A description of each solution, including the duration of each effort
- Examples of actual deliverables produced (redacted where required)
- Identification of responsible resources actively engaged in solution/deliverable
- Understanding of PA Act 129 objectives, deliverables and requirements
- A summary of solutions with timelines, key milestones, resource requirements, costs-to-achieve, used successfully at an EDC
- Experiences with electric utilities in North America with over 1,000,000 customers
- Vendor views on potential savings, reliability improvements, efficiency improvements and consumer benefits
- Regulatory experiences in PA or other jurisdictions
- Relevant experience with SAP systems and/or interfaces
- Documentation materials

Finally, each component RFP had specific selection criteria for vendors to meet as listed below.

Smart Meter RFP

The smart meter RFP sought to gain information about a vendor, its product(s) and its ability to demonstrate experience in the installation and implementation of smart meter technology. The specific criteria for the smart meter vendor were:

- Demonstrated understanding of remote service switches, service limiting, and pre-paid technologies including the management of regulatory challenges in implementation
- Demonstrated knowledge of theft and tampering strategies and solutions
- Demonstrated strategies for low-income and high-risk customers
- Knowledge and experience regarding security and privacy issues related to meter data
- Knowledge of smart meter rules/standards (NIST, IEEE, ANSI, NERC, CIP)
- Knowledge of enabling components (ZigBee, remote service switch)
- Knowledge of meter reading with automation
- Experience with smart meter supporting communications infrastructure assessment and analysis
- Knowledge of smart meter system operating life
- Knowledge of linkage between network and meters
- Meter manufacturer industry knowledge

Head End System RFP

The Companies define a Head End to include the Head End unit and the wireless communications (LAN) from and to the meter, excluding the backhaul. Below is a list of information that this RFP sought:

- Demonstrated understanding of remote service switch, service limiting, and pre-paid technologies including the management of regulatory challenges in implementation
- Demonstrated knowledge of theft and tampering strategies and solutions
- Demonstrated strategies for low-income and high-risk customers

- Knowledge and experience regarding security and privacy issues related to meter data
- Knowledge of smart meter rules/standards (NIST, IEEE)
- Knowledge of enabling components (ZigBee, remote service switch)
- Experience with smart meter supporting communications infrastructure assessment and analysis
- Knowledge of linkage between network and meters
- Experience with various communication components available today and how they natively work with meters
- Meter manufacturer industry knowledge

Meter Data Management RFP

The MDMS is designed to manage and retain the volumes of information that will be gathered from meters. In addition to the general requirements, the MDMS RFP inquired into the following:

- Knowledge of business unit implementation impacts
- In-depth knowledge of Itron MV-90 system, including system interface for measuring and recording customer demand, load and kWh usage, interval metering relative strengths regarding infrastructure
- Criteria / metrics for vendor's system performance
- Knowledge of data management and reporting practices and solutions
- Experience with Energy Efficiency ("EE") / Demand Response ("DR") programs based on customer class
- Assessing demand-side management impacts on PA smart meter plan
- DR savings metrics and measures
- Understanding of how EE/DR ties back to Act 129 filing
- Vendor deliverables acceptance sign-off / Criteria

Backhaul RFP

The Companies define backhaul as all service between the AMI LAN takeout points and the Head End. Below is the information that the backhaul RFP asked for:

- Experience with smart meter system communication backhaul
- Experience with public networks

- Experience with communication network challenges
- Experience deploying on commercial and private networks
- Experience on sonnet, routing switching, IPv4 versus 6
- Experience with message modeling and traffic on public and private networks
- Overall understanding of network performance
- Experience with network management and security
- Knowledge of network requirements and network capacity
- Experience with distribution automation communications

Deployment RFP

In addition to the above criteria, the Deployment RFP also included:

- Field experience in deployment and implementation and workforce management systems
- Meter field services technician work in scheduling and planning
- Customer requests, service orders and exceptions management

RFP Evaluation and Assessment
Upon receipt of the responses to the RFPs, each response underwent the following process:

- Initial Evaluation
- Objective evaluation
- Subjective evaluation
- Oral presentation by vendors

This process resulted in the recommended solution set forth in Chapter 3.

Initial Evaluation

Based upon the results of the RFIs, the preliminary testing and the RFPs, three Head End vendors were selected for further consideration; two for meters; eight for backhaul; two for MDMS; and four for meter deployment.

Some vendors who received an invitation chose not to respond. In the case of the MDMS RFP, this immediately led to the final two vendors. However, the entire RFP evaluation process was still undertaken so that the evaluators had an objective analysis of the solution being offered.

Objective and Subjective Evaluation

The objective evaluation consisted of compiling the responses received from the vendors and ensuring that their proposals were relevant, met the functionality needs of the Companies' intended AMI system, and provided answers to clarifying questions. The subjective evaluation consisted of eight to twelve people (depending on component) reading the vendor responses.

Oral Presentations

The oral presentations were designed to provide the evaluation team with an opportunity to seek further clarification on responses to requirements and clarifying questions, validate and confirm the short list, and get any updates on pricing that might be available.

Once the evaluation process was completed, the SMIP Team selected the technologies that met the business, technical and functional requirements and commenced testing in an effort to determine if in fact the various technology components actually performed as described by the various vendors.

Lab and Field Testing Process

Each major component was tested in both a test lab and in the field, with the results incorporated into the overall vendor/technology evaluations. The smart meter test lab was designed to provide a controlled "under the roof" environment to test smart meter technologies and related supporting infrastructure and perform vendor evaluation for smart meter products as input to selecting technologies for the field assessment. The test lab environment was built to house multiple meter forms from several meter vendors, as well as the smart metering solution including Head End systems and MDMS systems. Integration to SAP occurred in the test lab environment. The end-state production environment was mirrored as closely as possible, taking into account cost and time.

The Reading, Pennsylvania test lab was set up in Q4 2010 with two MDMS systems, three Head End systems and primary and secondary meters. As a result of the merger with Allegheny, the SMIP Team developed a test lab at West Penn's facilities in Connellsville, Pennsylvania. Approximately one hundred meters were tested in each of the labs.

Lab Testing

Figure 2.4 shows the types of testing that were performed in the test labs:

Figure 2.4 Types of Testing

Testing type	Description
Smart Meter Component Testing	Verified that meter, head-end, MDMS & SAP components met the Companies' requirements and satisfied usability, compatibility with other components, communication, and reliability criteria.
Functional Testing	Verified that the integrated smart meter system supported the necessary functionality as defined in the Companies' test requirements.
Integration Testing	Verified that the integration between applications and systems functioned correctly.
Communication Testing	Verified that all components communicated through the network from the meter to head-end in both directions.
Security Testing	Verified that the application provided an adequate level of protection for confidential information and data belonging to other systems.
Error Handling Testing	Verified that the system properly detected and responded to exception conditions. The completeness of error handling determines the usability of a system and ensures that incorrect transactions and data are properly handled.

Test Activities Matrix/Test Phases

Figure 2.5 illustrates the testing activities within each phase. Each stage represents a known level of physical integration and quality. Even though the test lab is shown as a first step, it is expected that some test scenarios (e.g. component, network testing and verification of environments) will continue throughout the entire test life cycle and beyond. The testing activities executed include:

Figure 2.5 Test Activities Mapping to Test Phases

TYPE OF TEST	Test Lab Initial Test	Field Preparation	Test Lab "Business Process " Testing	Field Test	Ongoing Testing
Component Testing	■			■	
Network Testing	■			■	
Verify environments	■	■		■	
Integration		■	■	■	
Deployment verification	■			■	
Execute test scripts	■	■	■	■	■
Record results	■	■	■	■	■
Document defects	■	■	■	■	■
Regression	■	■	■	■	■
Reporting	■	■	■	■	■

Tests were prioritized into one of three ratings to further assist entry/exit activities. The three ratings are as follows:

- HIGH – These are "must pass" tests and are absolutely critical to the success of the smart meter implementation project.
- MEDIUM – These tests are run once high priority tests have been completed and passed.
- LOW – These tests are considered optional or "nice to have" and were conducted after all high/medium tests have been completed, should time permit.

Risk Assessment and Contingencies

The following risk assessment and contingency procedures were driven by the technical requirements of the solution and business functions related specifically to testing. Risks were prioritized into one of three classes to further assist their assessment and mitigation. The three classes were:

- HIGH – execution of the mitigation unlikely at present time, increasing probability that risk will occur and result in stated impact to Lab and Field Test

- MEDIUM – execution of mitigation not confirmed, though feasible at present time. Risk considered moderate until mitigation in place
- LOW – unlikely event will occur or workarounds currently in place, and therefore poses minimal risk

Test Lab Business Process Test Criteria Requirements

The following subsystems were tested during the Business Process Testing Phase:

- SAP – MDMS subsystem
- AMI network subsystem
- Smart meter infrastructure subsystem

Smart meter technology testing was executed by subsystem to reduce the complexity of the testing process and to provide a baseline of solution components that passed a specific set of tests. The testing in the lab was executed to validate the business functionality of the integration touch points between the meter to Head End, Head End to MDMS and MDMS to SAP, and overall end-to-end business processes in the smart meter integration chain.

The following functional categories were tested in the Business Process Test Phase:

- Meter installation & registration
- Meter reading
- Billing
- Critical alarms and events
- Remote service switch
- Security
- Outage detection (including security)
- Other business processes

At the conclusion of the test lab business process testing, vendors and technologies were identified to participate in the field assessment.

Field Tests

The smart meter field assessment added an additional dimension to testing and began to further explore and validate the network and communications infrastructure. The investigation and assessment had to occur in actual field conditions that resembled typical operating conditions for the Companies. The field assessment afforded the Companies the opportunity to test the network under conditions of increased distance, data demands and topographical conditions beyond the test lab.

Field assessment preparation work began in Q4 2010 with actual testing beginning in Q2 2011. The field trial focused on testing the throughput and coverage of the network communications solutions(s) and initially included installing meters in the Fox Gap and York/Pleasureville, Pennsylvania areas. Both of these locations are within Met-Ed's service territory. Met-Ed was chosen as the test region due to its proximity to the test lab in Reading.

Participation in the initial trial was voluntary, and the Companies selected approximately 350 customers who agreed to participate. The initial trial helped the Companies understand firsthand how smart metering will impact customers, and what the Companies can do to improve the customer experience, including additional communications to consumers and "best practices" for addressing resolution of technical issues.

In 2012, the Companies also conducted lab and field testing in of enhanced functionality offered by an Itron/Cisco solution. This test involved approximately an additional 350 meters and took place in Connellsville, Pennsylvania, located in West Penn's service territory.

Field Assessment

The field assessment vendor scorecard provided a process to capture field assessment test results. The vendor solution was scored based on test results, defects, issues and risks identified during the testing in order to validate that the solution in fact met all of the business requirements as specified by the Companies.

Using the same methodology that was employed in the test lab, the team identified specific criteria applicable to the Field Assessment Test Phase and developed the vendor scorecard to compare vendors against each other. Vendor scoring was performed on both quantitative and qualitative criteria and took into account the resolutions of any open issues from the field assessment execution

Between the completion of the evidentiary hearing in May 2013 and the release of the Administrative Law Judge's Recommended Decision in November 2013, the Companies continued testing the end-to-end solution that was to be implemented during the Solution Validation Stage. Based on the results of this testing, the Companies now believe they can accelerate the deployment of smart meters in

Penn Power's service territory and completely build out Penn Power by the end of 2015, rather than only install 60,000 smart meters as originally proposed.

Consistent with the Deployment Plan, the Companies also began negotiations with all major vendors during the period between the close of the evidentiary hearing and the end of 2013. Based on these negotiations, the Companies have in place the contracts necessary to complete this accelerated build out as described in this Revised Deployment Plan.

CHAPTER 3. SMART METER SOLUTION AND DEPLOYMENT STRATEGY

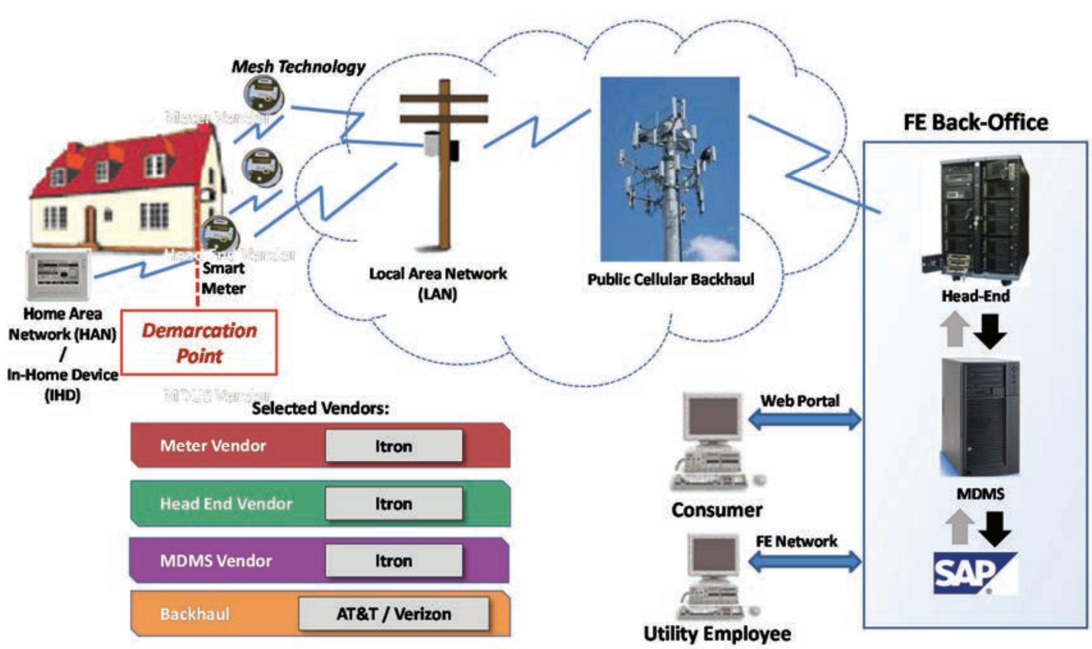
3.1 Overview

This chapter presents recommendations for the smart meter technology solution, the vendors to provide that solution, and the build-out/meter deployment/meter functionality schedules.

As discussed in Chapter 2, the recommended architecture and infrastructure solution is based upon an extensive technology needs assessment that addressed both the “current state” of each of the Companies and the vendors and equipment capable of supplying the functionality needed to meet Commission requirements. The outcome of this assessment is a technological solution that details the systems environment needed to implement smart meters and the identification of the vendors who can provide the key solution components to deliver all of the functionality specified in Act 129 and the Implementation Order.

The following chart provides a graphical representation of the smart meter solution, which is detailed in Section 3.2 below.

Figure 3.1 PA Companies Smart Meter Solution



The Companies are recommending a phased deployment strategy that anticipates three distinct stages: (i) the Post Grace Period ("PGP") Stage; (ii) the Solution Validation Stage; and (iii) the Full-Scale Deployment Stage. Under this strategy, the Companies expect to install approximately 98.5% of all smart meters between January 1, 2014 and mid-2019 ("Deployment Period"), with the remaining 1.5% of the meters being installed thereafter through December 31, 2022. The Companies will build out Penn Power's system (approximately 170,000 meters) during the Solution Validation Stage. Thereafter, Full-Scale Deployment will commence and continue until all smart meters are installed.

The Original Deployment Plan contemplated an average of 3,000 meters per day, five days per week. After discussions with installation vendors, the initial average installation rate will be paced at approximately 1,900 meters per day, five days per week, with the potential to accelerate such deployment to as many as 3,000 meters per day, five days per week should circumstances and conditions warrant[9]. And, while the meters being installed will have the capability to provide the functionality required by Act 129 and requested by the Commission, the actual functionality of the smart meter will not be available until the communication network is constructed in the area. It is currently anticipated that this will lag installation by approximately three months. The entire deployment strategy is described in detail in Section 3.3.

3.2 Smart Meter Vendor, Functionality and Solution Architecture

3.2.1 Meter Vendor

Itron is the recommended meter vendor based on the vendor selection process described in Chapter 2. The Itron smart meters selected by the Companies are capable of providing all of the functionality required by Act 129 and the Commission's Implementation Order as the Companies' network is deployed as described in Section 3.3, including the following specific features.

Remote Service Switches

The smart meters will be able to remotely connect and disconnect customers. The Companies intend to implement the reconnect function and will implement the remote disconnect function only upon request by the customer and in compliance with Chapter 56 of the Commission's regulations.

[9] Savings and cost estimates are conservatively based upon a constant installation rate of 1,900 meters per day, five days per week.

Read Intervals

Meter reading will be an automated, scheduled process through which meters read, record, and send interval meter readings and other data on a regular frequency. Initially, interval meter readings will be taken at hourly intervals, while register readings which, in essence, accumulate the interval reads, will be done on a daily basis. While the meters are capable of obtaining 15-minute (or shorter) interval data, this functionality will not be made available upon installation because significant issues, such as how the storage of such data should be paid for and by whom, have not been resolved. Because these issues are common among all of the Pennsylvania EDCs, the Companies will await further guidance from the Commission before pursuing the implementation of shorter interval reads.

Meter Storage, Open Standards, Upgradability and Remote Programming Capability

The smart meters are capable of storing data and have open standards consistent with nationally recognized standards. The meters are also upgradable and reprogrammable.

Voltage Monitoring/Outages and Restoration

The smart meters can measure and record voltage information at the meter, and transmit it to the Head End. The proposed architecture allows for the creation of reports that can be utilized by the Companies, in conjunction with existing capabilities, to analyze and assess the overall health of power distribution to the meter. Voltage monitoring alone, however, does not provide the level of accuracy and insight at the transmission and distribution level needed to support predictive, proactive outage management prevention and resolution. Rather, this new functionality will supply additional information to support the existing outage management capabilities. In order to automate outage reporting and restoration, the smart meter infrastructure must be in place and then interfaced with the Companies' current outage management system. Therefore, this functionality will not be available at the time of installation. Given that full-scale deployment will not begin until 2017, the Companies have not prepared a cost benefit analysis of this functionality for purposes of this Plan, but will be doing so during the later stages of the Deployment Schedule.

Net Metering

The smart meters will support the ability to provide net metering. Itron meters support energy received and delivered as well as profile loads where customers have existing generation sources such as wind and solar.

Solution Architecture
In order to provide the requisite functionality, an entire network of hardware and communication systems must be integrated. The main components of this network includes (i) the Smart Meter; (ii) the Head End; (iii) the Meter Data Management System ("MDMS"); (iv) the Companies' Legacy systems; (v) a Communication Network; and, while not part of the Companies' network, (vi) the customer's HAN. Components (ii) through (vi) and recommended vendors, where applicable, are discussed below.

Head End

In the proposed architecture, the Head End serves primarily as the gateway for all communications to the meters and other connected devices, such as collectors. It collects unvalidated meter data (e.g. consumption, interval, event data, power status, etc) and transmits it to the MDMS. Based on the RFP responses and test results, the Companies have selected Itron as the Head End vendor.

MDMS

Itron was also selected as the MDMS vendor. The MDMS will receive, store, validate, estimate, and aggregate data from the Head End, and processes meter data in three steps: Validation, Estimation, and Editing ("VEE"). The MDMS serves as the primary repository of all measurement, status, and event data collected by the smart meters. The MDMS is also the gateway for communication with the smart meters supporting data requests, commands, and alert messages from/to the Companies' other information systems, such as Customer Care & Billing, Work & Asset Management, and Work Force Management.

In the validation step, the MDMS reviews the unvalidated data from the smart meters and compares it to expected values. Meter reads that fall outside the high/low range or exceed the variance of expected values, fail validation and are flagged. Subsequently, invalid, incomplete, or missing reads are estimated along with reads that fail validation. The VEE process ensures that the Companies have validated smart meter data available for customer billing and operations.

Additional functions of the MDMS include the processing of remote service orders, status data, and event data on significant changes in the state of system or network resource, network application, data flow or security.

3.2.2 Other Existing Legacy Systems

As a result of the additional smart meter functionality, the Companies anticipate the need to upgrade certain legacy systems:

Operational Data Store ("ODS")

The ODS is the repository for interval data. The current ODS will need to be upgraded to support the proposed smart meter solution and future smart meter technology developments.

SAP

The successful integration of the smart meter components, the MDMS, and the Companies' core applications is crucial to the success of the SMIP Project. SAP will remain in place as the Companies' primary system for customer and billing information, but it will be upgraded to support the proposed smart meter solution and future smart meter technology developments.

3.2.3 Communications Network

Network communications is not a single solution, but consists of a series of components that enable meters to communicate with collectors and a backhaul, in which collectors communicate with the Head End. Based on the results of the RFP process, the Companies propose to construct a smart meter network as shown in more detail in Figure 3.1.

In the proposed network, Itron meters will use radio frequency (for which a license is not required) to dynamically discover each other and form a mesh network that connect them to communication devices known as collectors, creating a LAN.[10]

The LAN connection between an individual meter and the collector in the Companies' proposed architecture will use a proprietary communications protocol that is unique to the meter vendor. The collector will then link to a Wide Area Network ("WAN") which uses a standard protocol for "backhaul" services to connect the meter to the Head End.

[10] The diverse geographic and urban density nature of the Companies' service territories makes it unlikely that a single meter network vendor technology will be capable of servicing 100% of the smart meters, and a small population of meters will require alternative solutions. The Companies have determined that less than 5% of customers across the Companies are located in areas where RF meters may not be able to form an RF mesh or join a neighboring mesh due to the distance from the nearest meter, terrain, subterranean location, etc. ("RF Challenged" meters). In such cases, the Companies will utilize a point-to-point ("PTP") solution, e.g., cellular communication. In some cases where the location is not RF Challenged, a PTP solution might also be utilized if it is considered more cost-effective than building an RF mesh in the local area.

During the design and RFP processes, the risks and rewards of public versus private backhaul WAN network options were considered. Generally, the use of public cellular networks is preferable for the following reasons:

- Public carrier networks already exist and are available for immediate implementation to facilitate deployment timelines.
- The Companies have ongoing relationships with public carriers, which are large, established companies.
- The three primary public carriers (Verizon, AT&T and Sprint) participate in industry standards organizations to ensure that their network supports directives from NERC, NIST, etc.

In comparison, private network options carry greater risk:

- The construction of a private network would challenge the Companies' ability to achieve timely deployment.
- The Companies would have to invest significant resources for the private network in order to comply with international standards.
- Private carriers are smaller companies, introducing additional risk.

As a result of this consideration and the RFP responses, the Companies concluded that the public carrier option is generally able to meet more of the necessary criteria for a well-developed smart metering environment that would comply with legislation and open standards. The Companies therefore propose to use a blend of AT&T and Verizon network services in their territories.

In order to address the fact that these networks include equipment outside of the Companies' physical control, network intrusion prevention systems will be inserted between internal systems (including Head Ends) and the meter network for inbound traffic monitoring. This will add an independent security control between key points in the network.

3.2.4 Home Area Network ("HAN")/Internet

The HAN is a data network contained within a user's home that is expected to communicate from the smart meter to in-home devices ("IHDs"). The purpose of the HAN will be for the enablement of direct access data to the customer's premise. IHDs may include in-home displays, smart thermostats, power switches, and other load control devices. While the smart meters will have the capability of supporting data transmission to and from these IHDs, the functionality is only available should the customer elect to purchase the devices. As explained in Chapter 2, the Companies will not be providing IHDs or HAN technologies to customers, instead leaving them to the competitive market. The Companies also anticipate that the HANs and IHDs will utilize the public internet for two major roles in the smart meter technical solution:

- Connecting the Companies' customers and authorized third parties to resources that are made available by the Companies, such as a customer web portal; and
- Connecting authorized third parties to the customer home networks, allowing the authorized third party to retrieve information from the customer's home network and IHDs, including the non-validated interval data from the Companies' smart meters.

3.2.5 Data Exchange Standards

By Order entered December 6, 2012 at Docket No. M-2009-2092655, the Commission established data exchange standards for current business processes. Specifically, the Commission directed that all EDCs subject to the smart meter provisions of Act 129 address standards for attaining RTP and TOU pricing capabilities, provide the EDC's current capability to provide a minimum of 12-months of historical interval usage data via electronic data interchange ("EDI"), and to incorporate meter-level interval usage data capabilities. Because the Companies' enrollment and billing system is currently programmed to accept dual billing and bill ready EDC-consolidated billing (i.e., the functions the Commission has already said present the best options for attaining RTP and TOU pricing capability), the Companies currently have the capability to provide 12-months of historical interval usage data via EDI, and the Companies currently incorporate meter-level interval usage data as directed by the Commission. Therefore, the Companies are already meeting these Commission directives.

3.3 Deployment Strategy

3.3.1 Deployment Schedule

As noted previously, the Companies are recommending a phased deployment strategy which anticipates three distinct stages: (i) the PGP Stage; (ii) the Solution Validation Stage; and (iii) the Full-Scale Deployment Stage.

The PGP Stage, which commences on January 1, 2013 and concludes with the completion of deployment, currently scheduled by December 31, 2022, addresses not only the need to provide smart meters for all new service requests received on or after January 1, 2013 ("New Construction") and for all customers requesting a smart meter prior to their scheduled installation date ("Early Adopters"), but also addresses contract negotiations, final RFPs and other pre-deployment activities.

New Construction/Early Adopters: In order to provide the functionality required by Act 129 during the PGP Stage, the Companies will implement the following process for all New Construction and Early Adopter installations:

- For new construction for which a temporary or permanent service application is received on or after January 1, 2013, the customer will be provided with the RF smart meter included in the recommended technology solution, which will eventually be able to communicate with the smart meter network infrastructure. The recovery of both the meter and related installation costs will be through the Companies' applicable standard Smart Meter Technologies Charge Rider, which is more fully discussed in Chapter 5. Customers will not be billed additional fees for the meter or other installation costs beyond that charged to all metered customers through the Smart Meter Technologies Charge Rider. During the period between smart meter installation and the build-out of the smart meter network in the area where a New Construction smart meter installation occurs, neither the communication functions of the meter nor smart meter functionality will be available and meter reads will be done manually using existing meter reading and billing procedures.
- For Early Adopters, once the customer pays the incremental costs for the meter and related installation,[11] a Point-To-Point ("PTP") smart meter that meets the basic Act 129 functionality requirements will be installed, This smart meter will communicate via a public cellular network and will provide on-line access to validated meter data within 24-48 hours and access to unvalidated meter data via a direct access interface to a device that is part of the Home Area Network.[12] Meter reads for billing purposes will continue to be done manually using existing meter reading and billing procedures until the smart meter network infrastructure becomes available at the customer's location and the PTP meter is replaced with the RF smart meter selected as part of the smart meter technological solution.

Contract Negotiation/RFPs: During the period between the filing of the Deployment Plan with the Commission and approval of the plan by the Commission, the SMIP Team negotiated final terms and conditions with the selected vendors, selected a systems integrator ("SI") and project management office ("PMO") through the RFP process described in Chapter 2, finalized contracts with the SI and PMO and worked with consultants and selected vendors to develop

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[11] Tariff provisions implementing the Companies' proposals for Early Adopters were filed with the Commission on October 31, 2012 and approved on December 21, 2012. *See* Docket Nos. R-2012-2332803; R-2012-2332776; R-2012-2332785; R-2012-2332790.

[12] In the event public cellular coverage is unavailable for a requesting customer, the Companies will investigate alternative solutions on a case-by-case basis.

construction schedules, all with the goal to have everything in place to start construction of the smart meter infrastructure upon approval of this Revised Deployment Plan.

The Solution Validation Stage incorporates two activities: the build out of the infrastructure needed to install smart meters and a testing period in which a "mini version" of the end to end smart meter solution is constructed and tested prior to full scale deployment. This stage will begin with the installation of all smart meters and supporting infrastructure in the Penn Power service territory. This stage is expected to start in mid-2014 and continue until late 2015.

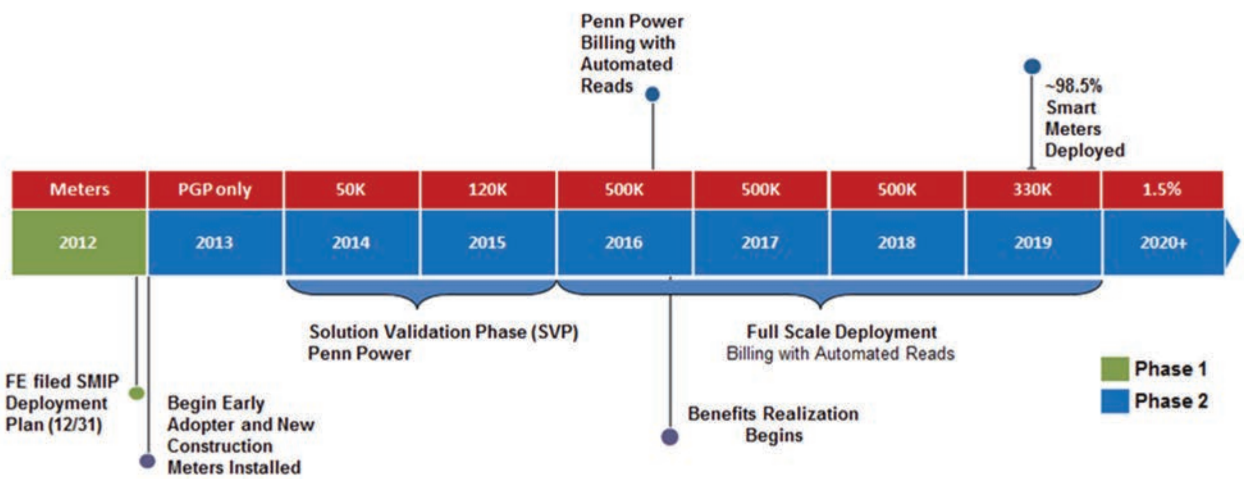
- *Build-Out Activities*. This period begins upon Commission approval of this Deployment Plan and will continue for approximately 18 months. During this period, the Companies will commence and complete construction of the smart meter solution infrastructure, or "backbone" for the Penn Power service territory. This will involve the installation of meters, collectors, range extenders, network communications, and meter data management systems for testing.

- *Solution Testing Activities*. As the infrastructure is built, the Companies will install meters in Penn Power's service territory. This territory was selected because it includes the wide range of challenges the SMIP Team anticipates encountering during full deployment across all of the Companies. Approximately 50,000 meters will be installed in the second half of 2014 and the remaining 120,000 will be installed in 2015, so as to allow for testing of scalability and resolution of communication, functionality and installation problems encountered in a contained and controlled environment, thus minimizing costs of deployment and customer frustration. Only after all such problems are resolved will the Companies commence the final Full-Scale Deployment Stage, currently anticipated to commence in early 2016.

The Full-Scale Deployment Stage will commence upon resolution of all problems encountered during the Solution Validation Stage and will continue until all meters are installed on or before December 31, 2022. During this stage, the remainder of the smart meter infrastructure will be concurrently built in each of the Companies' respective service territories, starting with the most populated areas first. All remaining smart meters will be installed during this Stage at an anticipated meter installation rate of 1,900 meters per day, five days per week, and potentially ramping up to 3,000 meters per day if circumstances and conditions warrant. At this pace, the Companies expect to install approximately 98.5% of all meters by mid-2019, with the remaining 1.5% of the meters being installed thereafter through December 31, 2022. The 1.5 % of the installations represent those installations that may require alternative communication solutions or difficult to reach locations such as remote hunting cabins. Any similar situations discovered in Penn Power's service territory are included in the 1.5% estimate and will be addressed in the time frame discussed above.

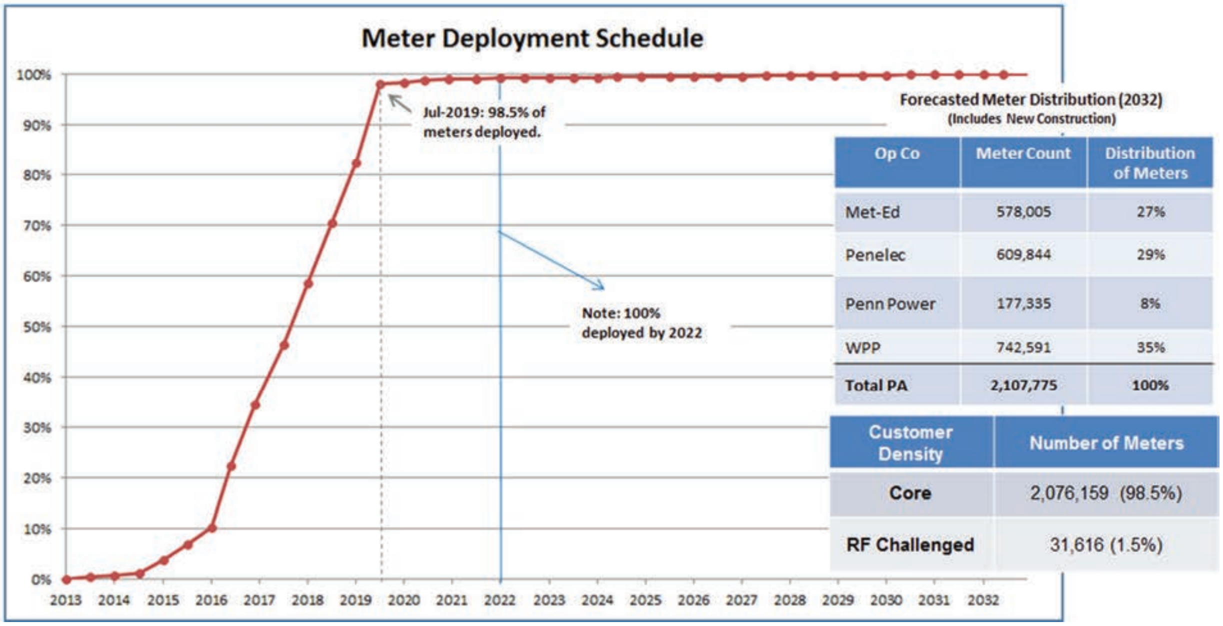
Figure 3.2 illustrates the anticipated implementation schedule while Figure 3.3 illustrates the meter deployment schedule, assuming that the Accelerated Deployment Schedule is adopted:

Figure 3.2 – Smart Meter Deployment Plan Timeframe*



* Estimated schedule for planning purposes

Figure 3.3 – Smart Meter Deployment Timeline – 2014 to 2019

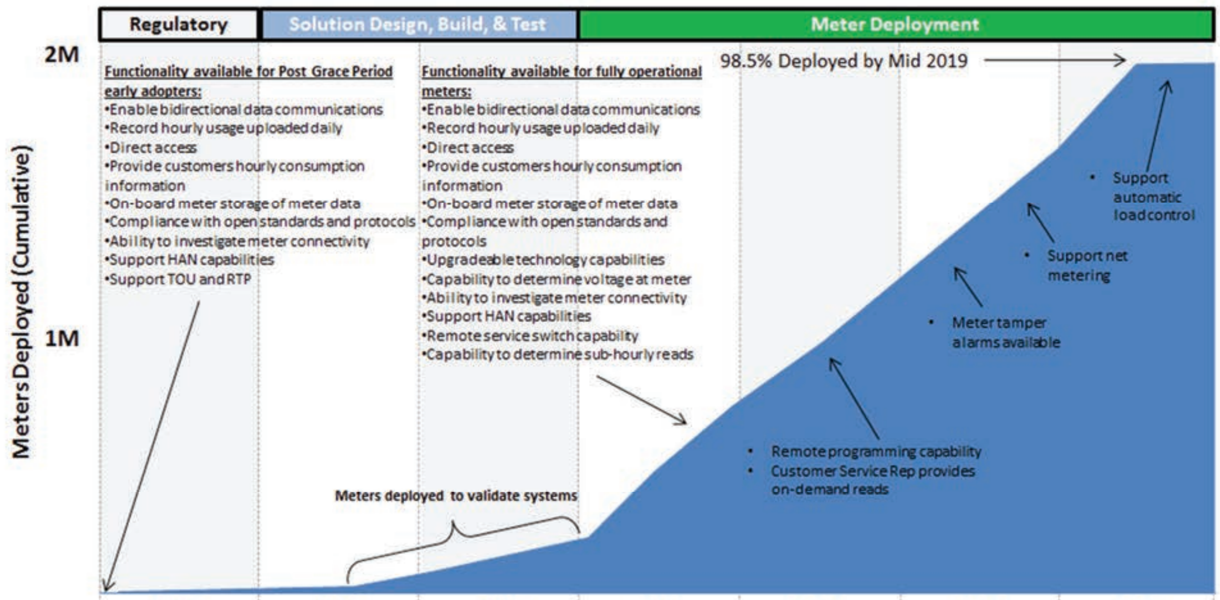


3.3.2 Meter Functionality

The meters being recommended as part of the Companies' smart meter solution all comply with open standards and protocols, can be remotely programmed and can be upgraded as technology advances. They are also capable of providing all of the functionality required by Act 129 and requested by the Commission in its Implementation Order. However, not all of this functionality will be available immediately upon installation. As Figure 3.4 depicts, basic functionality required by Act 129, plus the ability to investigate meter connectivity will be available to Early Adopters upon installation of their meters during the PGP Stage. This is because a different meter will be installed with cellular communication capabilities in order to meet Act 129 requirements while the smart meter infrastructure is being built. However, the RF meters being installed as part of the smart meter mesh network solution will not have this functionality until the communication network is in place in the area. It is currently anticipated that there will be a lag of approximately three months between installation of the meters and when such functionality is available to the customer. As Figure 3.4 indicates, once this occurs, the RF meter will provide all of the functionality offered during the PGP Stage, as well as voltage monitoring capability, remote switch capability and the ability to determine sub-hourly reads remotely. The Companies currently anticipate that remote programming capability and the ability for customer service representatives to make on-demand reads will be available in late 2017, while meter tamper alarms and automated net metering support will be available sometime in 2018.

Advanced automatic load control is expected to be available sometime during 2019, however, these timeframes are projections based on information as known today. Events may occur which could affect these timelines, both positively and negatively.

Figure 3.4 – Deployment Timeline with Estimated Functionality



	2013	2014	2015	2016	2017	2018	2019
PGP*	14,000	28,000	42,000	56,000	70,000	84,000	98,000
Staged	-	50,000	170,000	670,000	1,170,000	1,670,000	2,000,000

Meters Deployed (Cumulative)

*Includes early adopters and new construction. Functionality for new construction will not be available until network is available in the area.

3.3.3 Meter Installation

The Companies anticipate that approximately 90% of the meter installations will be standard and will be performed by both Company personnel and qualified contractors. Should the installer encounter a hazardous condition or another situation involving the meter box on the Companies' side of the meter that would normally be left to the customer to repair, the necessary repairs will be made and the installation completed at no cost to the customer. Based on discussions with other utilities, as well as the Companies' past history, the Companies estimate that up to 5% of the installations will require such additional work and have included the costs of such work in the overall plan budget.

The Companies anticipate that the remaining 10% of the installations will involve non-standard, more complex installations and will utilize internal resources for these installations. Such complexities may include installations for large C&I

customers, new construction sites, hard-to-access locations, and cases with special meter forms or electrical requirements.

CHAPTER 4. FINANCIAL ANALYSIS

In response to Act 129 and subsequent Commission Orders, the Companies initiated a detailed assessment and planning effort in preparation for the implementation of smart meters and AMI technologies. A central part of planning was the creation of a detailed SMIP financial analysis model ("Financial Model") to estimate and analyze the future costs and potential operational savings associated with this Deployment Plan. Implementation and ongoing operational costs were projected over a 20-year period.

The data underlying the financial analysis were produced through a highly interactive assessment process originally involving consultants from IBM and Black & Veatch in 2011 and 2012. This analysis was refined and updated by Accenture, Inc., and Harbourfront Group, along with professionals from the impacted business units of the Companies, the FirstEnergy finance department and its rate department in 2013 and 2014. The data were reviewed and updated in an iterative process throughout 2011, 2012 and again in 2013. The original analytics quantified estimated costs and potential operational savings based on information known as of August, 2012. This analysis was supplemented with additional information, analytics and experiences through 2013 and modified to reflect the Accelerated Deployment Schedule. Activities performed in the development of the Financial Model included:

- Defining the scope and components of the smart meter program
- Gathering relevant operational data and smart meter project projections
- Evaluating and validating data
- Identifying key smart meter project financial analysis modeling variables and assumptions
- Developing the analytical modeling structure
- Constructing a detailed view of the smart meter project financial analysis
- Evaluating the reasonableness of the Financial Model results based on comparisons with other utility smart meter program results
- Reviewing the Financial Model results with affected business units, the FirstEnergy financial analytics group and FirstEnergy management

Numerous scenarios were considered, with three initially being selected for more in-depth analysis:

- 6-year Two-stage Deployment Scenario ("Original Recommended Deployment Schedule"): Assumes 98.5 percent of all meters are installed by the end of 2019. Net cost: $852 million (nominal) and $560 million (NPV).

- 6-year Accelerated Scenario (West Penn Joint Settlement Scenario): Assumes 90 percent of all meters installed by the end of 2018, with remainder installed by the end of 2019. Net cost: $844 million (nominal) and $562 million (NPV).
- 7-year Deployment Scenario: Assumes 98.5 percent of all meters are installed by the end of 2020. Net cost: $865 million (nominal) and $557 million (NPV).

The financial analyses included in this chapter were originally based on the 6-year Recommended Deployment Schedule which anticipated all smart meter infrastructure being built and 98.5 percent of all smart meters being installed between January 1, 2014 and December 31, 2019. Based on these analyses, the estimated cost of implementing this Deployment Plan over 20 years is $1.258 billion in nominal dollars, $667.4 million of which are for capital expenditures ("Capex") and $590 million for Operations and Maintenance ("O&M") costs. Approximately $816 million will be spent during the six year Deployment Period. The estimated total operational cost savings over the 20 year period that the Companies believed might be realized under the Original Deployment Plan was $406 million in nominal dollars.

Assuming the Accelerated Deployment Schedule is adopted, the estimated cost of implementing the Revised Deployment Plan over 20 years is still $1.258 billion in nominal dollars, $668 million of which will be for CAPEX and $590 million for O&M costs. Approximately $815 million will be spent during the Deployment Period. The estimated total potential operational cost savings over the 20 year period is estimated to be $417 million.

In addition to this analysis, which focuses on the project from the Companies' perspective, the Companies further analyzed the Revised Deployment Plan from the customer's perspective. This analysis is discussed in Chapter 4.

Below is a breakdown of the Revised Deployment Plan costs by Company, as generated by the Financial Model:

Figure 4.1 Estimated Costs and Potential Savings
($ Millions, Nominal, 20 Years)

	Total PA	Met-Ed	Penelec	Penn Power	WPP
Capital Costs	$ 667,390,350	$ 181,338,201	$ 192,354,386	$ 60,847,753	$ 232,850,010
O&M Costs	$ 590,204,938	$ 162,940,051	$ 172,612,059	$ 46,040,407	$ 208,612,421
Total Costs	$ 1,257,595,288	$ 344,278,252	$ 364,966,445	$ 106,888,160	$ 441,462,431
Total Savings	$ 417,023,753	$ 102,911,556	$ 124,772,459	$ 34,358,311	$ 154,981,427

4.1 Scope and Assumptions

The financial analysis assumes a 20 year life cycle, starting with the beginning of the Post-Grace Period Stage on January 1, 2013, and continuing through 2032. The Financial Model used to perform the financial analysis assumes that the Accelerated Deployment Schedule is adopted and that deployment will commence in mid-2014.

General Financial Inputs and Assumptions

- The combined state and federal FirstEnergy marginal tax rate is 41%.
- No Allowance for Funds Used During Construction ("AFUDC") is expected because the capital that will be invested in systems, network and meters will be used and useful in the year in which those costs are incurred.
- No costs are included for stranded assets, and any stranded assets will continue to be recovered in the base rates.
- Potential operational savings could be realized beginning in 2016 and lag meter deployment by one year.
- Base line costs, employee levels and other factors will be based on actual employee, cost and other metric levels as of December 31, 2013. For purposes of estimating savings, budgeted levels for 2013 were assumed.
- Equipment and outside vendor service costs were derived from pricing received through the RFP process.
- Labor related costs are fully loaded and include annual growth and human resources factors.
- Costs incurred prior to January 1, 2013 are not included in the analyses.

Book and Tax Depreciation

Each of the cost categories were assessed to determine if they were capital or O&M related costs. For Capex, the estimated book lives used for depreciation purposes were 15 year for smart meters and communications equipment, 5 years for hardware and 7 years for software. Book lives were determined based on input from external resources and internal subject matter experts while tax lives were based on IRS guidelines.

Escalation Rate

The Financial Model assumes an escalation rate of 2.56% for labor.[13] A zero percent escalation rate was assumed for equipment and material costs in recognition that material costs may increase over time while technology costs may decrease over time.

Weighted Average Cost of Capital ("WACC")

The Financial Model assumes the following Weighted Average Cost of Capital rates:

Figure 4.2. Weighted Average Cost of Capital by Company

8.17%	8.68%	9.14%	11.29%

The weighted average cost of capital for Met-Ed, Penelec and Penn Power is calculated in accordance with the Commission order entered June 9, 2010 at Docket No. M-2009-2123950 approving the Joint Petition for Approval of Smart Meter Technology Procurement and Installation Plan. The weighted average cost of capital for West Penn is calculated in accordance with Commission order entered June 30, 2011 at Docket No. M-2009-2123951 approving the Amended Joint Petition for Settlement of All Issues.

The Companies also assessed the project from the residential customer's perspective utilizing a discount rate of .37%, which represents a current typical interest rate for a one-year Certificate of Deposit (CD)[14]. This analysis is discussed in Chapter 4.

[13] Provided by the Companies Business Analytics department based on the average 12 month (Mar 2011 - Mar 2012) escalation index for the Utility industry being 2.56% from U.S. Bureau of Labor Statistics (http://data.bls.gov/cgi-bin/print.pl/news.release/eci.t09.htm)

[14] Based upon the average of the initial Local Results Range for one year certificates of deposit for the Reading, Pennsylvania area as of March 10, 2014.

Deployment Inputs and Assumptions

- No costs are included for in-home customer devices. It is assumed that this is a competitive service, the costs of which will not be paid for by the Companies.
- Meter-related repairs on the Companies' side of the meter will be necessary prior to the installation of some of the smart meters. Based on discussions with other utilities involved in smart meter projects, the Financial Model assumes such repairs will be needed for 5% of all installations at an estimated cost of $500 per installation. These costs have been capitalized as part of the meter cost.
- Based on discussions with other utilities involved in smart meter projects, the Financial Model assumes a meter failure/replacement rate of 1% through 2023 and 2% thereafter, with a manufacturer's warranty covering the first five years of each smart meter's operational life. The cost of the warranty has been capitalized as part of the meter cost.
- Radio Frequency network devices are assumed to have an annual failure rate of 1%
- The Financial Model assumes 100% full deployment, with no provision made for customer opt out.
- The Financial Model assumes that the Accelerated Deployment Schedule will be followed and that all meters will be installed no later than 2022.
- 100% of the required field network devices will be deployed.
- The Companies will perform all complex meter installations which are estimated to be 10% of all installations.

Geographic Density Inputs

The Financial Model assumes four different cost profiles for the installation of meters across different geographies that were derived from pricing received through the RFP process:

Figure 4.3 Cost Profiles by Customer Class and Density

Customer Class	High Density	Medium Density	Low Density	Very Low Density
Residential	$8	$9	$11	$17
Commercial	$11	$12	$15	$24
Industrial	$33	$37	$43	$65

4.2 Overall Program Costs

The costs incurred to implement this Deployment Plan have been grouped into the following cost categories: (i) Meter and LAN; (ii) Information Technology ("IT"); (iii) Systems Integration; (iv) Network and Network Management; (v) Program Management; (vi) Business Staffing; and (vii) Communications/Change Management. Costs within each of these components were further broken down as either capital or O&M within the year(s) in which these costs would be incurred. The costs have been presented on both a nominal and net present value basis, using a 20 year analysis period. The NPV analysis has been included in order to provide a more consistent way in which to evaluate the total net costs of competing scenarios taking into account the time value of money from the Companies' perspective. The costs have been adjusted throughout this 20 year period for escalation and growth of the smart meter system based on the six year Accelerated Deployment Schedule. Below is a breakdown of total costs, Capex and O&M:

Figure 4.4

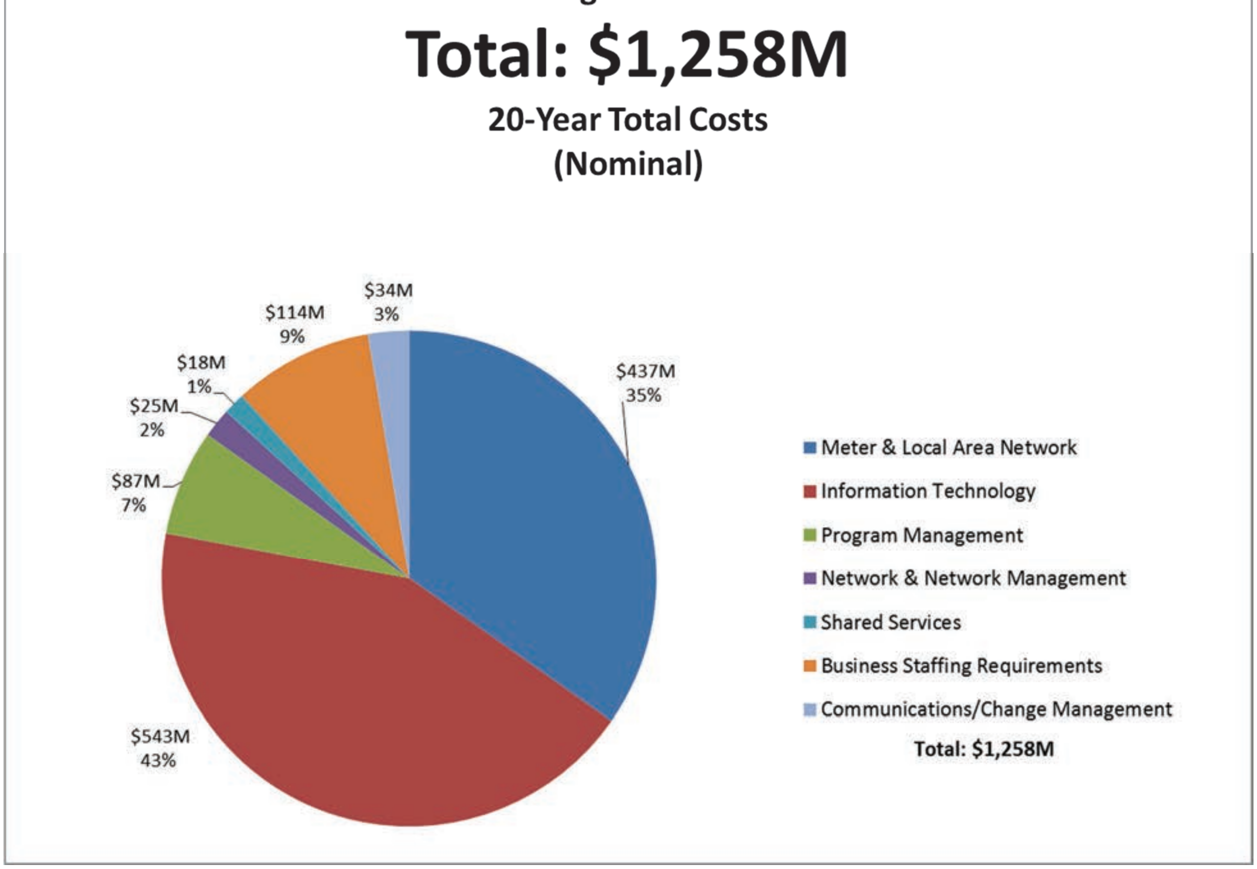


Figure 4.5

Capital Total: $668M

20-Year Total Costs
(Nominal)

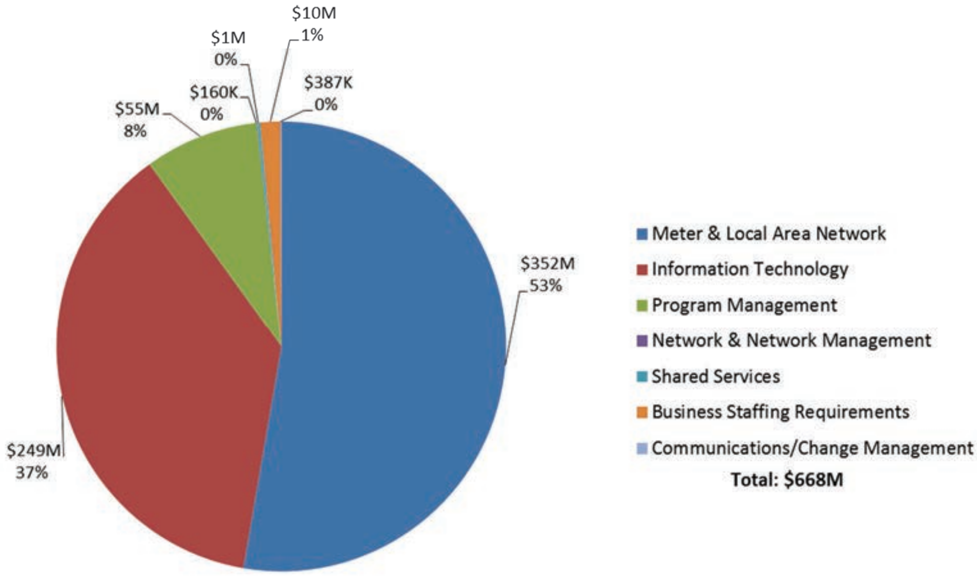
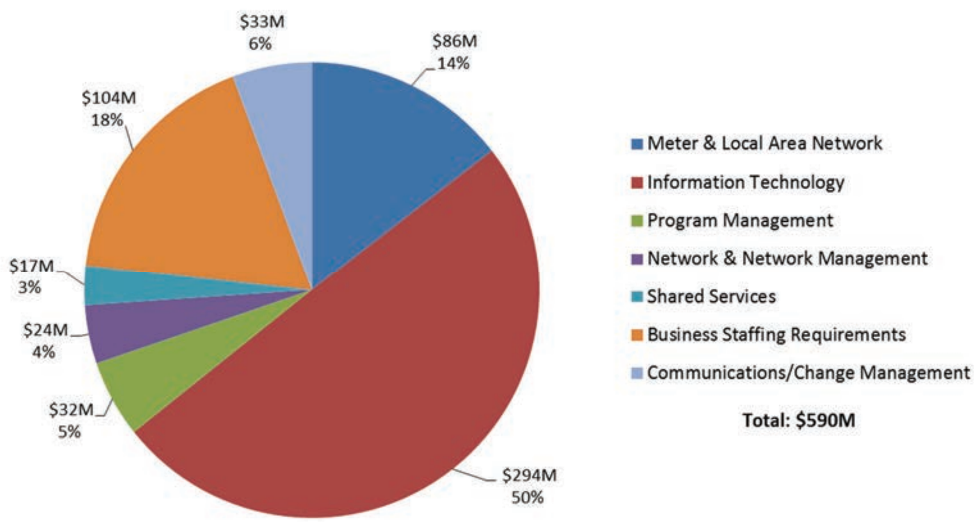


Figure 4.6

O&M Total: $590M

20-Year Total Costs
(Nominal)



The cost estimates for each of the above cost categories were based on the following sources:

Figure 4.7 Cost Estimate Sources

Cost Category	Source of Cost Estimate
Meters & Local Area Network	Vendor RFP responses and internal and consulting resources based on previous experience
Network & Network Management	Vendor RFP responses and IBM resources based on past experience with Oncor, CenterPoint, SCE, Sempra, Pepco, FPL and Duke
Information Technology	Vendor RFP responses and IBM/FE resources based on past experience
Systems Integration	Vendor RFP responses and IBM resources based on past experience
Business Staffing Requirements	Workshop on future state and IBM/FE resources based on past experience
Communications/Change Management	Workshop on future state and IBM/FE resources based on past experience
Program Management	Workshop on future state and IBM/FE resources based on past experience with Oncor, CenterPoint, SCE, Sempra, Pepco, FPL and Duke

4.2.1 Costs by Program Component

The estimated costs presented in this section are cumulative over the 20-year evaluation period and are presented in nominal dollars. All vendor labor during the Deployment Period has been capitalized and the Companies' labor costs are considered to be O&M.

Meter and Local Area Network
Total Estimated Cost: $437.5 million (35% of total project costs).

Meters (Capex): $328.1 million

Meters (O&M): $58.4 million

LAN (Capital): $23.7 million

LAN (O&M): $27.3 million

Approximately $351 million will be spent during the Deployment Period. The meter Capex costs include a 60 month warranty, initial installation costs, and shipping and handling. Meter O&M is predominantly for the labor needed over 20 years to replace failed meters. The local area network Capex costs are for collectors and repeaters, as well as installation and testing costs. All of these cost estimates were derived from the vendor pricing received through the RFP process.

Network and Network Management
Total Estimated Cost: $24.6 million (2% of total project costs).

Public Backhaul (Capex): $0.2 million

Public Backhaul (O&M): $24.4 million

Approximately $5.0 million is expected to be spent during the Deployment Period. Capex costs for the public backhaul represent a one-time installation and set-up fee plus a refresh cost every ten years. The O&M costs include 20 years of annual service fees. All of these cost estimates were derived from the vendor pricing received through the RFP process.

Information Technology
Total Estimated Costs: $542.7 million (43% of total project costs).

Infrastructure (Capex): $126.7 million

Infrastructure (O&M) costs: $41.3 million

Software Applications (Capex): $38.0 million

Software Applications (O&M): $88.3 million

Resources (Capex): $84.3 million

Resources (O&M): $164.1 million

Approximately $277 million is expected to be spent during the Deployment Period. Infrastructure Capex costs are for the various components, such as MDUS, ODS, and Head End, that comprise the smart meter infrastructure. Vendor costs to install infrastructure components are capitalized and therefore no O&M costs are attributed to the infrastructure cost subcategory. Capital costs for software applications include software for the web portal, data warehouse, MDUS, Head End, security applications, and SAP. O&M costs for the software applications subcategory are resource and maintenance costs associated with software applications. Resources include internal and contractor IT resources who will be responsible for implementation of the IT technologies needed to support a Smart

Meter rollout. All information technology costs were derived from the vendor pricing received through the RFP process.

Systems Integration
Total Estimated Costs: $87.3 million[15] (7% of total project costs).

Systems Integration (Capex): $54.9 million

Systems Integration (O&M): $32.4 million

Approximately $83.4 million is expected to be spent during the Revised Deployment Plan period.

Systems Integration Capex costs includes all the costs required to integrate the Companies' enterprise systems, including the Head End, MDUS, and SAP applications, in order to enable the sharing of data across applications. O&M costs include requirements identification and business processes definition and development. IBM's past experience serving as systems integrator for other similar implementation projects was used to estimate the cost inputs for this category. The estimate assumes that one systems integrator will handle business process design, architecture design, operational design, building and testing for the integrated system, vendor management, security and portal development in order to realize synergies associated with methodologies and staffing.

Business Staffing and Change Management Requirements
Total Estimated Costs: $147.3 million (12% of total project costs).

Business Staffing (Capex) $9.6 million

Business Staffing (O&M): $103.9 million

Change Management (Capex): $0.4 million

Change Management (O&M): $33.4 million

Approximately $81 million is expected to be spent during the Deployment Period.

Business staffing costs include the labor and other related costs for incremental internal resources in various departments that support smart metering, including

[15] These costs do not include costs for the systems integrator's Project Management Office ("PMO"). Those costs are included as part of the program management cost category.

those departments needed to achieve the projected operational savings.[16] Change Management costs include the Companies' labor costs for training and internal and external communications, including support for any regulatory matters. These costs were estimated based upon Black and Veatch's experience with other communications plans, as well as through discussions with the Companies' communications department personnel and media cost information provided by those individuals.

Program Management
Total Estimated costs: $18.2 million (1% of total project costs).

PMO (Capex): $1.5 million

PMO (O&M): 16.7 $million

Approximately $15.3 million is expected to be spent during the Revised Deployment Plan period.

The systems integrator's Program Management Office ("PMO") is considered a capital cost and was derived from vendor pricing received through the RFP process. The systems integrator's PMO will be responsible for activities such as developing periodic scope, schedule and budgets for tasks to be performed through the Deployment Plan. It will also be responsible for quality control of the smart meter deployment plan, driving the installation schedule, managing external stakeholders, and developing project sub-plans. The costs of the Companies' PMO, which will be responsible for overseeing the daily activities of the systems integrator's PMO, represent internal labor and related costs. These costs are classified as O&M expenses. These costs were estimated by IBM based upon its experience in being involved in such activities for other utility clients.

4.3 Operational Cost Savings

The Financial Model also projected potential cost savings that may be realized by the Companies through the installation of smart meter technology. These savings categories include (i) Meter Reading; (ii) Meter Services; (iii) Back Office; and (iv) Contact Center. All of the potential operational savings would be avoided costs. The potential savings projections were derived from an assessment of the impacts of business process changes that will occur as a result of the installation of smart meter technology. For each avoided cost, a determination was made as to whether it is categorized as an O&M cost or a Capex cost. A 20-year analysis

[16] For example, the Companies anticipate having to initially increase call center personnel before reducing staffing levels because of anticipated increases in call volume during the installation of the smart meters.

period is used, with assumptions made based on information as currently known. The savings are cumulative over the 20 year period and are presented in nominal dollars. The estimated potential cost savings that the Companies believe may be quantifiable and verifiable are summarized below.

Figure 4.8
Estimated Potential Operational Savings Summary (Update)

Operational Savings		**20-year Cumulative (Nominal Value)**
Meter Reading		
Meter Reading O&M	$	378,684,741
Meter Reading Handhelds O&M	$	889,996
Meter Reading Handhelds Capital	$	2,654,060
Claims	$	45,406
Meter Services		
Meter Services O&M	$	12,142,190
Meter Services Handhelds O&M	$	37,387
Meter Services Handhelds Capital	$	990,219
Back-Office		
Back-Office/Cust Accounting O&M	$	19,243,257
Contact Center		
Contact Center O&M	$	2,336,497
Total	$	**417,023,753**

4.3.1 Meter Reading

Estimated Potential Realizable Savings: $382.3 million (Approximately 92% of the total projected program operational savings)

Reduction in work force: Approximately $378.7 million (O&M)
Reduction in hand held: Approximately $3.5million ($2.7 million Capex)
Claims: Approximately $0.05 million

Meter reading savings accrue through the elimination of the meter reading function, thus eliminating the need for manual meter readers and their handheld devices, and a reduction in related employee injuries and customer property claims. As a result of this reduction in work force, costs such as direct labor, overtime, fully loaded pension and benefits, and incentives are eliminated. Similarly, costs associated with employee uniforms, supplies, personal mileage and company cars can also be eliminated. Meter readers' handheld devices will no longer be needed and therefore capital costs associated with these devices, as well as the associated O&M maintenance costs can be eliminated over time. Finally, because there will be fewer customer site visits, there should be fewer OSHA and/or customer property damage claims.

The savings estimates are aligned with the smart meter deployment schedule and are based on the following assumptions:

- 100% of the meter reading positions will be eliminated by the end of 2022.
- The reduction in non-labor costs are proportional to the reduction in meter reading positions.
- Cost reductions are taken based on the percentage of meters installed, but lagged by one year.
- Annual retirement and attrition is estimated at a rate of three percent combined.
- Severance costs are estimated based on average current levels and will be subtracted from the calculated operational savings.
- Any necessary manual reads post-deployment will be executed by meter services staff.
- The average life of a handheld device is 10 years.
- The reduction in handheld devices is proportional to the reduction in meter reading positions and is aligned with the existing handheld replacement maintenance schedule and the proposed deployment schedule.
- Reduction in property damage and OSHA claims is proportional to the reduction in manual meter reading positions.
- No retraining of meter readers is assumed.
- Labor related budgets are escalated beginning in 2014 by 2.56% per year.
- There are no new projects/initiatives in 2013-2019 which may impact costs or staffing levels.
- Savings estimate assumes an acceleration of potential operational cost savings in Penn Power service territory consistent with the Accelerated Deployment Schedule.

Tracking of Savings: In order to track meter reading savings, the Companies will track the actual reductions in the meter reader headcount as well as the number of meter readers moved to other smart meter related positions. Only those meter readers that move to new smart meter related positions (if any) will be excluded from the savings calculation. The Companies will also track average Full Time Equivalent ("FTE") labor costs including wages, benefits and payroll taxes for the meter reading personnel. These costs, net of any severance costs, would be compared against the baseline meter reading labor costs as of December 31, 2013. Apart from labor costs, the Companies will also track all changes in fleet costs, claims, personal mileage expense, equipment, materials and supplies expense related to meter reading. The Companies will track other applicable metrics, such as number of meter reading handhelds in service, number of handhelds retired and those moved to other uses. Actual costs in each of the above cost centers during each year of the Deployment Plan will be compared against the 2013 baseline levels.

4.3.2 Meter Services

Estimated Potential Realizable Savings: Approximately $13 million (Approximately 3% of total projected program operational savings).

Reduction in work force: Approximately $12 million

Reduction in employee field tablets: Approximately $1 million (virtually all Capex)

Meter services activities include meter service personnel making customer visits for meter related issues and customer inquiries that need more technical explanations than can be provided by the customer contact center. Much of the potential cost savings is expected to arise as a result of reduction in work force and reduction in truck rolls. The installation of smart meters will reduce the need to dispatch a meter technician for activities such as (i) restoration of service upon receipt of customer payment (when service was disconnected for non-payment[17]); (ii) disconnection upon customer request or move out; and (iii) initiation of service upon customer request or move-in. The Companies will also be able to remotely "ping" the meters to determine if the meter is working. Customers will have access to more detailed information and it is assumed that many of the calls that required a technician to visit a customer will be able to be addressed by customer contact center personnel. With this automation and more detailed information being provided to customers, fewer Meter and Technical Support Services technicians will be needed, thus reducing workforce levels. Costs such as direct labor, overtime, fully loaded pension and benefits, and incentives will be reduced proportionately to the workforce reduction levels. Similarly, costs associated with

[17] The Companies will not implement this functionality for remote disconnect for non-pay partly due to Commission regulations and partly due to commitments made by West Penn in the Joint Settlement.

employee uniforms, supplies, personal mileage and company cars can also be eliminated. Fewer technician computerized tablets will be needed and therefore capital costs associated with these devices, as well as the O&M maintenance costs can be reduced over time.

While, overall, there is a reduction in resource requirements, some of the existing personnel, or new personnel, will be needed to support new types of field service orders associated with smart meters, such as repairing communication collectors. The possibility also exists that meter swaps could take longer due to more complex technology. Additional costs are expected in order to meet additional training requirements but cannot be estimated at this time. These costs would be netted against any realized savings.

The savings estimates are aligned with the smart meter deployment schedule and are based on the following assumptions:

- There will be a 99.5% reduction in tickets related to high bills, check readings, final reads for move outs, initial reads for move ins, and unblock dunnings
- Cost reductions are taken based on the percentage of meters installed, but lagged by one year.
- Labor savings are based on the average FTE labor rates by Company
- Training will be provided for personnel working with smart meters
- Current severance cost levels were assumed and will be netted against any cost savings.
- The reduction in tablets is proportional to the reduction in meter services positions
- The average life of a meter service tablet is 10 years.
- The Companies will continue to comply with Chapter 56 regulatory requirements prohibiting remote disconnect of service for non-paying customers without a site visit. Therefore, no savings associated with this function are included in the analysis.
- Non-labor operational savings are estimated to be proportional to the reduction of labor costs.
- Savings estimate assumes an acceleration of potential operational cost savings in Penn Power service territory consistent with the Accelerated Deployment Schedule.

Tracking of Savings: The Companies will track meter services related expense in a way similar to meter reading expenses. In addition, the Companies will also track other metrics related to Meter Services that are relevant to the determination of savings associated with the meter service calls discussed above and compare them to 2013 baselines.

4.3.3 Back Office

Estimated Potential Realizable Savings: Approximately $19 million, all O&M (Approximately 5% of total projected operational savings).

Back office activities involve resolution of high bill complaints and other billing related issues such as misreads, estimated reads, and move-in / move out reads. With the installation of smart meters the Companies anticipate a significant decline in the number of estimated bills and read errors. Also the Companies currently receive postcard reads from some customers that require manual entry by an accounting clerk. Smart meters will eliminate this task. More accurate and up-to-date information available through the online portal should drive customers to validate information online rather than requesting a bill investigation. As a result of the reduction or elimination of these tasks, fewer employees will be needed in the back office for meter related activities, thus reducing labor and labor related costs, as well as equipment and supply costs currently incurred to support these employees.

Because customers are not familiar with smart meters and the information that will be provided through smart meters, the Companies anticipate that customer inquiries will increase before reaching a reduced steady state. Therefore, increases in costs may occur before net savings are achieved.

The savings estimates are aligned with the Accelerated Deployment Schedule and are based on the following assumptions:

- A 99.5% reduction in manual re-bills will occur during steady-state, after deployment is complete, due to a reduction in estimation, manual reads, move in/move out errors, and stopped meters.
- There will be a 50% reduction in customer complaints requesting re-bills.
- A reduction in bill investigations is expected due to customer education and adoption of the online portal.
- Severance costs are based on current levels and will be netted against any savings.
- Average current labor rates by Company are assumed, with an escalation rate of 2.56%.

- Savings estimate assumes an acceleration of potential operational cost savings in Penn Power service territory consistent with the Accelerated Deployment Schedule.

Tracking of Savings: The Companies will track the actual reductions in the back office headcount as well as the number of back office personnel moved to other smart meter related positions. The Companies will also track average Full Time Equivalent ("FTE") labor costs including wages, benefits and payroll taxes for back office personnel. These costs, net of any severance costs, would be compared against the baseline back office labor costs as of December 31, 2013. In addition to costs, the Companies will also measure other back office metrics that are relevant to determining back office savings and compare them against a 2013 baseline.

4.3.4 Contact Center

Estimated Potential Realizable Savings: Approximately $2 million, all of which is O&M (Approximately 1% of total projected program operational savings).

The Contact Center is responsible for addressing all customer inquiries received through the Contact Center. More complex issues raised by the customer are forwarded to the Companies' back office for resolution. It is expected that there will initially be cost increases due to increased call volume arising from the installation of smart meters. The Companies intend to supplement current staffing levels through contract employees. Once smart meters are installed and customers become more familiar with the information that is being provided, it is expected that the call volume related to meter related customer inquiries will be reduced. Call volumes should be further reduced as customers become familiar with the use of the Companies' web portal that will include more detailed billing information, which can be verified on line. As a result, the Companies anticipate an eventual reduction in the number of employees needed to address meter related calls.

The savings estimates are aligned with the Accelerated Deployment Schedule and are based on the following assumptions:

- Calls will increase annually during deployment, as customers are educated about their smart meters, new rate structures, and new capabilities available to them; calls will peak in 2018 and decrease thereafter. This assumes a 10% increase in calls resulting in a net increase in personnel in 2018 but a net decrease in personnel by 2022.

- During deployment, the Contact Center expects to see an initial increase in call handling times and volumes caused by both the learning curve for customer service representatives, and increased customer questions due to new smart meter system functionality and increased data volumes.
- Billing call volumes are assumed to decrease by 25% by 2020 due to customer education and customer adoption of the online portal.
- Basic calls will be addressed by contractors, while more complicated issues will be addressed by either the Companies' Contact Center or back office personnel.
- Savings estimate assumes an acceleration of potential operational cost savings in Penn Power service territory consistent with the Accelerated Deployment Schedule.

Tracking of Savings: The Companies will track the actual back office headcount as well as the number of back office personnel moved to other smart meters related positions. The Companies will also track average Full Time Equivalent ("FTE") labor costs including wages, benefits and payroll taxes for the contact center personnel. These costs, net of any severance costs, would be compared against the baseline contact center labor costs as of December 31, 2013. In addition to costs, the Companies will also track other related metrics, such as contact center contractor costs, number of contact center calls, and the average duration of calls and compare them against a 2013 baseline.

4.4 Analysis of the Revised Deployment Plan From a Customer's Perspective

4.4.1 Background

The Original Deployment Plan incorporated the scenario with the overall lowest, risk adjusted cost from the Companies' perspective, based upon information known at the time the Original Deployment Plan was filed. For purposes of these comparisons, the Companies used their individual WACC as the discount factor for determining the NPV of each of the evaluated scenarios. This approach was appropriate when selecting the best scenario from those competing scenarios, given limited capital resources. However, because the Companies are now proposing to accelerate the original deployment schedule, the proposed modification must also be analyzed from the customer's perspective to determine if the Accelerated Deployment Schedule is financially superior for the customer. The analysis described below indicates that it is.

4.4.2 Analysis

- The model and modeling techniques used to develop the Original Deployment Plan were used to analyze the Revised Deployment Plan.
- All variable model inputs (e.g., the timing of costs and operational cost savings) were updated to reflect the construction of the entire Penn Power system between mid-2014 and the end of 2015, and the commencement of the Full-Scale Deployment Stage in early 2016.
- The net present value analysis used a discount factor reflective of the residential/small business customer, which, for purposes of the analysis was .37%. This rate represents the average of the initial Local Results Range for one year certificates of deposit for the Reading, Pennsylvania area as of March 10, 2014.

4.4.3 Results

Based upon the analysis described above, the total estimated cost of the Revised Deployment Plan on a nominal cost basis does not change. However, with the expansion of the Penn Power build out by approximately 110,000 meters, the acceleration of the completion of the Solution Validation Stage and the commencement of the Full-Scale Deployment Stage by one year, costs will be incurred sooner than originally contemplated. However, potential operational cost savings in Penn Power's service territory will be possible earlier than originally contemplated by virtue of the expanded and accelerated Solution Validation Stage and Full-Scale Deployment Stage operational cost savings will be similarly accelerated due to the earlier commencement of this stage. Therefore, the net projected operational cost savings is estimated to increase by approximately $11 million on a nominal dollar basis, and by $8 million on a NPV basis.

This analysis does not reflect any customer-specific benefits, such as integrated volt-var control, revenue assurance or time varying rates that may accrue to customers sooner than they otherwise would under the Original Deployment Plan.

Figure 4.9 summarizes the estimated costs and estimated operational cost savings under both the Original Deployment Plan and the Revised Deployment Plan:

FIGURE 4.9 - ESTIMATED COSTS AND ESTIMATED OPERATIONAL COST SAVINGS UNDER BOTH THE ORIGINAL DEPLOYMENT PLAN AND THE REVISED DEPLOYMENT PLAN
Output from SMIP Business Case Model

	Capital Cost (A)	O&M Cost (B)	Total Cost (C) = (A) + (B)	Cost Savings (D)	Net Cost (E) = (C) - (D)
Scenario: Original Deployment Plan with Companies' Discount Rates					
Nominal	$ 675,545,057	$ 582,050,231	$ 1,257,595,288	$ 405,518,837	$ 852,076,451
NPV	$ 393,662,712	$ 299,897,997	$ 693,560,709	$ 133,876,123	$ 559,684,586
Scenario: Revised Deployment with Companies' Discount Rates					
Nominal	$ 667,390,350	$ 590,204,938	$ 1,257,595,288	$ 417,023,753	$ 840,571,535
NPV	$ 438,406,700	$ 311,618,189	$ 750,024,888	$ 142,228,284	$ 607,796,604
Scenario: Original Deployment Plan with Customer Discount Rate					
Nominal	$ 675,545,057	$ 582,050,231	$ 1,257,595,288	$ 405,518,837	$ 852,076,451
NPV	$ 658,920,060	$ 563,621,001	$ 1,222,541,061	$ 386,459,773	$ 836,081,288
Scenario: Revised Deployment Plan with Customer Discount Rate					
Nominal	$ 667,390,350	$ 590,204,938	$ 1,257,595,288	$ 417,023,753	$ 840,571,535
NPV	$ 654,414,560	$ 572,022,644	$ 1,226,437,204	$ 397,924,450	$ 828,512,754

CHAPTER 5. COST RECOVERY AND SELECTED REGULATORY ISSUES

This Chapter addresses cost recovery, bill impacts and other regulatory matters.

5.1 Riders and Costs

Consistent with provisions of Act 129, all four of the Companies have elected to recover smart meter technology costs on a full and current basis through a reconcilable automatic adjustment clause mechanism under Section 1307 of the Pennsylvania Public Utility Code.[18] By order entered June 9, 2010 at Docket No. M-2009-2123950, Met-Ed, Penelec and Penn Power received Commission approval to recover smart meter technology costs through a reconcilable adjustment tariff rider called the Smart Meter Technologies Charge ("SMT-C") Rider, which became effective August 1, 2010. By order entered June 30, 2011 at Docket No. M-2009-2123951, West Penn received Commission approval to recover smart meter technology costs through SMT-C Riders, which became effective September 1, 2011.[19]

Aside from a compliance tariff update to the text of the West Penn SMT-C Riders to include the remaining collection of $5.1 million of costs incurred in 2009 and 2010 associated with the development of a smart meter plan, the Companies are not proposing any changes to the SMT-C Riders and intend to continue to recover through these riders the costs associated with this Revised Deployment Plan. The Companies anticipate this Revised Deployment Plan will be approved by the Commission by June 4, 2014.[20] Once this Plan is approved, the increased costs outlined in Chapter 4, along with the amount being collected in current SMT-C rates effective January 1, 2014 and the proposed SMT-C Rates proposed to be effective from July 1, 2014 through December 31, 2014, will be collected though the SMT-C Riders. As noted previously, Incremental costs of providing smart meters upon request to Early Adopters were addressed through a separate filing and have been approved by Commission Secretarial Letter dated December 21,

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[18] Pa.C.S. § 2807(f)(7).

[19] As provided for in the July 29, 2010 Commission Order, at Docket No. M-2009-2123950, the Companies may seek to roll smart meter costs into base rates in the next distribution base rate case and the Commission will determine then whether to allow it. The Companies contended in their Petition for Reconsideration seeking reconsideration of the June 9, 2010 Order that, in the future, it may be desirable to roll existing smart meter costs into base rates while continuing to recover new smart meter costs through their reconcilable SMT-C Rider. If the Companies seek, and the Commission allows, smart meter costs to be rolled into base rates, the smart meter recovery surcharge would be reset to reflect the amount included in base rates so that the Companies are not recovering the same costs both through base rates and the surcharge.

[20] In its March 6, 2014 Order, the Commission indicated that it would rule on this revised deployment plan within 90 days of the date of the Order.

2012 at Docket Nos. R-2012-2332803, R-2012-2332776, R-2012-2332785, and R-2012-2332790.

The Companies' Commission-approved SMT-C Riders consist of non-bypassable SMT-C rates designed to collect smart meter technology costs projected to be incurred during each calendar year, as well as recoup or refund, as applicable, under- or over-collections of actual smart meter technology costs from prior periods. The SMT-C rates are calculated separately for the residential, commercial, and industrial customer classes, and are expressed as a monthly customer charge to all metered customer accounts except for the rate applicable to West Penn's residential customer class, which is expressed as a dollar per kilowatt-hour charge.

The SMT-C Rider has two components. One is the current cost of smart meter technology projected to be incurred during each calendar year (referred to as the "Computational Year"). The second component is the reconciliation or "E-factor".

The types of projected smart meter technology costs recoverable under the SMT-C Rider include O&M expenses expected to be incurred during the Computational Year, an allocated portion of projected indirect costs during the same period that benefit all customer classes, and capital revenue requirements for assets placed in service. These costs are reduced by measurable and sustainable reductions in O&M and avoided capital costs attributable to the implementation of smart meter technology. Costs specific to a customer class are allocated to each customer class based upon direct assignment, and prospective general costs are allocated to each of the Companies' respective customer classes based on the annual average number of meters in each class as of June 30th immediately preceding the Computational Year.

The E-factor component of the SMT-C Rider reconciles actual smart meter technology costs incurred by customer class to actual SMT-C revenues (excluding Gross Receipts Tax). The reconciliation is calculated monthly for each of the Companies and results in an over- or under-collection by customer class. The cumulative net balance per customer class, including interest, is included for recovery or refund.

SMT-C rates for all of the Companies are filed with the Commission by August 1st of each year, to be effective the following January 1st. Each of the Companies files with the Commission an annual report of collections under their respective SMT-C Rider within 30 days after June 30th.

5.2 SMT-C Rates

Met-Ed, Penelec and Penn Power: The SMT-C rates are flat rates that are calculated and stated separately for the residential, commercial and industrial customer classes. The rates are monthly, non-bypassable customer charges and are billed on that basis. Consistent with Commission Order entered June 9, 2010 at Docket No. M-2009-2123950, all customers eligible for the installation of a smart meter are charged a SMT-C, regardless of whether or not they currently have a smart meter installed at their premises.

The 2013 monthly SMT-C rates for these Companies' customers were as follows:

Med-Ed:

- Residential - $0.96 per customer
- Commercial - $0.96 per customer
- Industrial - $1.05 per customer

Penelec:

- Residential - $0.95 per customer
- Commercial - $0.97 per customer
- Industrial - $0.95 per customer

Penn Power:

- Residential - $0.91 per customer
- Commercial - $1.01 per customer
- Industrial - $0.95 per customer

The 2014 monthly SMT-C rates for these Companies' customers currently are as follows:

Med-Ed:

- Residential - $1.79 per customer
- Commercial - $1.86 per customer
- Industrial - $1.79 per customer

Penelec:

- Residential - $1.74 per customer
- Commercial - $1.82 per customer
- Industrial - $1.74 per customer

Penn Power:

- Residential - $1.61 per customer
- Commercial - $1.72 per customer
- Industrial - $1.62 per customer

As a result of the revised deployment schedule included in this plan, which increases the number of meters and related equipment and infrastructure to be built in Penn Power's service territory between mid-2014 and the end of 2015, the estimated costs to be incurred are understated. Therefore, the amounts to be recovered are being revised for the last half of 2014 to reflect this increase in spending. The proposed updated 2014 monthly SMT-C rates for these Companies' customers proposed to be effective from July 1, 2014 through December 31, 2014 are as follows:

Med-Ed:

- Residential - $2.40 per customer
- Commercial - $2.36 per customer
- Industrial - $2.33 per customer

Penelec:

- Residential - $2.39 per customer
- Commercial - $2.39 per customer
- Industrial - $2.31 per customer

Penn Power:

- Residential - $2.99 per customer
- Commercial - $3.08 per customer
- Industrial - $2.98 per customer

West Penn. West Penn is also utilizing a SMT-C Rider and charging a SMT-C rate to metered customers during each billing month. Although commercial and industrial customers pay a flat monthly SMT-C rate, residential customers are charged a SMT-C rate based on the amount of electricity consumed. West Penn's SMT-C Rider recovers capital and O&M costs, provides West Penn with a return on capital investments, and collects costs and interest incurred in 2009 and 2010 associated with the development of a smart meter plan.

The 2013 monthly SMT-C rates for West Penn's customers were as follows:

- Residential - $0.00276 per kWh charged on each customer's monthly bill

- Commercial - $2.43 per customer per month

- Industrial - $2.03 per customer per month

The 2014 monthly SMT-C rates for West Penn's customers currently are as follows:

- Residential - $0.00303 per kWh charged on each customer's monthly bill
- Commercial - $2.89 per customer per month
- Industrial - $2.48 per customer per month

The proposed updated 2014 monthly SMT-C rates for West Penn's customers proposed to be effective from July 1, 2014 through December 31, 2014 are as follows:

- Residential - $0.00438 per kWh charged on each customer's monthly bill
- Commercial - $3.78 per customer per month
- Industrial - $3.44 per customer per month

5.3 Customer Impacts and Other Regulatory Issues

Bill Impacts and Bill Presentment

The percentage impact on a typical customer's monthly bill for each of Met-Ed, Penelec, Penn Power, and West Penn's commercial and industrial customers is expected to be minimal since the rates are flat charges and are not based on kWh usage. The percentage impact to residential customers will vary based upon the magnitude of generation charges, but is expected to be minimal in comparison to total electric charges.

The Companies have analyzed and estimated the costs of this Deployment Plan over a 20 year period. The chart set forth below summarizes the estimated bill impacts by customer class over this period.

Figure 5.1
Monthly Bill Impacts (Nominal)

Op Co	Residential		Commercial		Industrial	
	Range	Average	Range	Average	Range	Average
Met-Ed	$0.91 - $4.59	$2.36	$0.96 - $5.27	$2.89	$1.05 - $6.24	$3.52
Penn Power	$0.44 - $5.30	$2.56	$0.47 - $6.35	$3.09	$0.78 - $8.15	$4.13
Penelec	$0.76 - $4.50	$2.26	$0.76 - $4.50	$2.72	$0.95 - $6.10	$3.35
West Penn	$0.70 - $4.92	$2.64	$1.09 - $5.73	$3.27	$2.03 - $6.73	$4.30

**Reflects charges on a kWh basis rather than a flat charge.*

Consistent with the Commission's March 6, 2014 Order, SMT-C charges will no longer be displayed as a separate line item on the customer's bill. For all metered customers, the Companies will eliminate that presentation and fold the SMT-C charge into the overall distribution rate effective July 1, 2014.

True-ups and Contingency

The return earned by the Companies through the SMT-C and SMT riders is only on capital investments associated with the smart meter solution included in this Deployment Plan. The return varies year to year and is based on the capital structure, with approximately half the weight on the return on equity and half the weight on the cost of debt. The capital structure, return on equity, preferred stock, and cost of debt utilized in the SMT-C Riders are calculated in accordance with Commission Order entered June 9, 2010 at Docket No. M-2009-2123950 for Met-Ed, Penelec and Penn Power; and the Commission Order entered June 30, 2011 at Docket No. M-2009-2123951 for West Penn.

To calculate each year's SMT-C rates, the Companies project the costs of implementing the Deployment Plan that are expected to be incurred during the Computational Year for each customer class. If the Companies spend more than they recover through the SMT-C Rider, the under-collection is collected through a customer class-specific reconciliation E-factor. If the Companies spend less than they recover through the SMT-C Rider, the over-collection is refunded through a customer class-specific reconciliation E-factor. Because the SMT-C Riders include a provision for an annual true-up to actual costs, the Companies do not incorporate any contingency into the yearly capital and O&M expenditure estimates.

West Penn Settlement Issues

In 2009 and 2010, West Penn incurred approximately $45.1 million of costs associated with the development of a smart meter plan. As part of its 2009 SMIP case, West Penn was authorized to collect $40 million of such costs through its SMT-C Rider. The remaining $5.1 million was challenged by some of the parties involved in that proceeding, who questioned whether it was appropriate to recover the $5.1 million through the SMT-C Rider. As part of the Joint Settlement, West Penn was permitted to file for and request recovery of these remaining costs in either its next distribution rate case and/or when it filed its smart meter deployment plan. West Penn elected the latter. Based on the Commission's March 6, 2014 Order in which recovery of these costs was authorized, the remaining $5.1 million is included for recovery through the SMT-C Rider over the remaining 5.5 year amortization period (through February 28, 2017) previously approved by the Commission for recovery of the other $40 million.

Legacy Meters

For meters that are removed or become obsolete due to the installation of smart meters ("Legacy Meters"), the Companies propose to retire the meters out of stock, continue their existing depreciation schedule unaltered over their remaining lives as a regulatory asset, and continue cost recovery through base rates. The rate base equivalent of the regulatory asset for Legacy Meters plus the Cost of removal net of Salvage will continue to be included in the respective Company's rate base. This protocol would have no current impact on customer rates. For accounting purposes, the Companies are asking the Commission to approve an accounting treatment that would allow them to create a "regulatory asset" for the Legacy Meters with a recovery schedule equal to the remaining depreciable lives of the assets per the Companies' depreciation records.

CHAPTER 6. COMMUNICATIONS CHANGE MANAGEMENT AND TRAINING

During the Assessment Period, the SMIP Team was divided into nine workstreams, including two that involved "External Communications and Consumer Awareness Strategies" and "Change Management and Training". These teams combined efforts and developed an Internal and External Education and Communications Plan ("Comm Plan"), a Change Management Plan and a Training Plan. At the time of filing the Original Deployment Plan, vendors and technology were just recently selected, and construction of the smart meter infrastructure was not expected to begin until late 2013. As a result, the Companies indicated in the Original Deployment Plan their intent to complete these plans prior to such construction commencing. During the period between the close of the evidentiary hearing in May, 2013 and the end of 2013, the Companies developed a draft Comm Plan. It has been provided to all parties to the case and comments received to date have been incorporated. Consistent with the Commission's March 6, 2014 Order, the Companies will host a stakeholder meeting during the second quarter of 2014 so as to provide interested parties the opportunity to provide input on the Comm Plan prior to it being filed with the Commission shortly thereafter.

Customer: GREGORY KOLLMAR / 805611799
Contract Acct: [redacted]
Service Address: 1749 FREEPORT RD,ARNOLD PA 15068

Created On: 04/22/2025
Date Range: 01/01/1900 to 04/22/2025

Customer Contact History

Contact Date	Created Date	Contract Acct	Created By	Description
11/26/9999 16:16:28	11/26/2019	[redacted]	Tammy Taylor	PUC/BPU Complaint-Written
Formal PUC Complaint docket# C-2019-3014650 rec'd 11/26/19 pertains to smart meter refusal. ttaylor Satisfied Not Applicable: Reason - Manual work				
04/20/2025 23:27:47	04/20/2025	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
02/19/2025 23:33:45	02/19/2025	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
12/19/2024 23:29:36	12/19/2024	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
10/20/2024 23:26:50	10/20/2024	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
08/19/2024 23:30:19	08/19/2024	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
06/18/2024 23:24:41	06/18/2024	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
05/07/2024 18:09:47	05/07/2024	[redacted]	EAILOGINWM6	Ready Pay Create
No 105919601 - $ 76.79 - 05/07/2024				
05/07/2024 18:06:43	05/07/2024	[redacted]	INTV IVR	Account Balance Inquiry
05/07/2024 18:06:18	05/07/2024	[redacted]	INTV IVR	IVR eBill Offer - Decline
Customer declined eBill Enrollment				
04/18/2024 23:23:30	04/18/2024	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
02/19/2024 23:21:41	02/19/2024	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
12/19/2023 23:20:28	12/19/2023	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
10/19/2023 23:20:51	10/19/2023	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
09/19/2023 12:01:03	09/19/2023	[redacted]	CS General Purpose Batch	Data Change Request (Rejected)
Customer doesn't have an active contract with the EGS				
09/14/2023 01:15:10	09/14/2023	[redacted]	CS General Purpose Batch	West Penn Power Consolidated Bill Enroll Letter
09/13/2023 12:02:48	09/13/2023	[redacted]	CS General Purpose Batch	Supplier Change Request (Accepted)
08/20/2023 23:22:47	08/20/2023	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
06/19/2023 23:25:24	06/19/2023	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
06/16/2023 12:01:16	06/16/2023	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				
04/19/2023 23:25:04	04/19/2023	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
04/19/2023 06:00:58	04/19/2023	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				
02/19/2023 23:21:03	02/19/2023	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
12/19/2022 23:23:23	12/19/2022	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
12/15/2022 12:02:24	12/15/2022	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				

Customer Contact History

Contact Date	Created Date	Contract Acct	Created By	Description
10/19/2022 23:27:06	10/19/2022	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
09/20/2022 06:04:06	09/20/2022	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				
08/21/2022 23:23:07	08/21/2022	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
06/19/2022 23:21:35	06/19/2022	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
06/17/2022 12:02:38	06/17/2022	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				
04/19/2022 23:22:07	04/19/2022	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
02/16/2022 23:22:37	02/16/2022	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
02/15/2022 12:01:41	02/15/2022	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				
02/15/2022 12:01:11	02/15/2022	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				
12/19/2021 23:21:08	12/19/2021	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
12/15/2021 06:05:01	12/15/2021	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				
10/19/2021 23:21:31	10/19/2021	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
10/18/2021 12:02:42	10/18/2021	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				
09/17/2021 12:02:00	09/17/2021	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				
08/19/2021 23:20:18	08/19/2021	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
06/21/2021 23:17:39	06/21/2021	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
06/18/2021 12:00:51	06/18/2021	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				
05/19/2021 12:02:21	05/19/2021	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				
04/21/2021 23:20:13	04/21/2021	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
02/21/2021 23:19:16	02/21/2021	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
12/21/2020 23:19:43	12/21/2020	[redacted]	ZEDBTCH	Periodic Meter Read Notification
Periodic Meter Read Notification				
12/21/2020 06:37:10	12/21/2020	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				
10/21/2020 23:20:17	10/21/2020	[redacted]	ZEDBTCH	Periodic Meter Read Notification
PA SMIP Periodic Meter Read Notification				
09/17/2020 06:09:15	09/17/2020	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
RATE CATEGORY CHANGED				
08/19/2020 23:30:45	08/19/2020	[redacted]	ZEDBTCH	Periodic Meter Read Notification

Customer Contact History

Contact Date	Created Date	Contract Acct	Created By	Description
	PA SMIP Periodic Meter Read Notification			
06/18/2020 23:28:42	06/18/2020	[redacted]	ZEDBTCH	Periodic Meter Read Notification
	PA SMIP Periodic Meter Read Notification			
06/17/2020 15:51:59	06/17/2020	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
	RATE CATEGORY CHANGED			
04/20/2020 23:33:58	04/20/2020	[redacted]	ZEDBTCH	Periodic Meter Read Notification
	PA SMIP Periodic Meter Read Notification			
03/19/2020 06:00:56	03/19/2020	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
	RATE CATEGORY CHANGED			
02/19/2020 23:18:14	02/19/2020	[redacted]	ZEDBTCH	Periodic Meter Read Notification
	PA SMIP Periodic Meter Read Notification			
02/11/2020 09:17:31	02/11/2020	[redacted]	Beth Lemmon	Meter-Other
01/20/2020 10:11:35	01/20/2020	[redacted]	Kelly Shenigo	Meter-Other
12/22/2019 23:18:47	12/22/2019	[redacted]	ZEDBTCH	Periodic Meter Read Notification
	PA SMIP Periodic Meter Read Notification			
12/20/2019 06:15:30	12/20/2019	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
	RATE CATEGORY CHANGED			
11/26/2019 16:17:33	11/26/2019	[redacted]	Tammy Taylor	Contract Account Changed
	Dispute date for formal complaint.			
11/22/2019 03:30:26	11/22/2019	[redacted]	CS General Purpose Batch	DSPTRIGHTS Letter
11/21/2019 16:55:21	11/21/2019		Victoria Adelsberger	Smart Meter Refusal - No Benefit
	Smart Meter Refusal (SMR) Process Contact via CRM Smart Meter Installed? = Existing refusal flag? =X Open smart meter exchange order = Is the customer satisfied with the outcome of the meter inquiry? =N Is the customer refusing install? =Y Refusal reason? =7-No Benefit Smart meter installed today? = Script read? =Y s/w DONNA KOLLMAR (wife) calling to report her complaint with the PUC. adv her service will not be disc. Created By: Adelsberger,Victoria C			
11/21/2019 16:53:36	11/21/2019	[redacted]	Victoria Adelsberger	Premise Information Changed
	Old Premise Phone:(724)337-7165 New Premise Phone:(724)337-7340 s/w DONNA KOLLMAR added ph # per request Created By: Victoria C Adelsberger			
11/21/2019 16:53:36	11/21/2019		Victoria Adelsberger	Personal Data Changed
	Old BP Phone:(724)337-7165 New BP Phone:(724)337-7340 s/w DONNA KOLLMAR added ph # per request Created By: Victoria C Adelsberger			
11/21/2019 16:51:49	11/21/2019	[redacted]	Jennifer Elkins	General Inquiry
	mrs kollmar veriired [redacted] filed complaint with puc wants it noted and to make sure srvc not turned off Satisfied Not Applicable: Reason - Call Transferred			
11/21/2019 14:33:13	11/21/2019	[redacted]	Heather M Woomer	Smart Meter Inquiry

Customer Contact History

Contact Date	Created Date	Contract Acct	Created By	Description
	donna kollmar - wife CALLING TO LET US KNOW SHE FILED A COMPLAINT W. THE PUC IN WRITING. SHE HUNG UP WHILE ON HOLD Satisfied Not Applicable: Reason - Send DSPRTS			
11/21/2019 14:15:25	11/21/2019	[redacted]	Trudy Cain	General Inquiry
	donna kollmar - wife - vai customer states that she filed a complaint with the PUC regarding installation xfer to sma Satisfied Not Applicable: Reason - Call Transferred			
11/19/2019 17:14:07	11/19/2019	[redacted]	Heather M Woomer	Smart Meter Inquiry
	donna kollmar, spouse CUSTOMER STILL REFUSING SMART METER STATED SHE DOESNT WANT IT DUE TO HEALTH CONSERNS, TRIED TO GET BP TO TALK TO ME ABOUT HER CONCERNS BUT SHE WOULDNT SHE STATED THAT BECAUSE I WORK FOR THE COMPANY I WOULDNT CARE ABOUT HER CONSERNS AND IT WOULDNT HELP. BP STATED THAT HER FRIEND TOLD HER THAT SHE COULD PAY $10.00/MO TO REFUSE THE SMART METER. ADV THAT IS NOT TRUE, SHE CAN REFUSE THE SMART METER HOWEVER THE SERVICE CAN BE DISCONNECTED. ISSUED PUC INFO Customer was not satisfied. Rights provided to customer.			
11/19/2019 16:58:43	11/19/2019	[redacted]	Jeanne Carson	General Inquiry
	s/w donna kollmar spouse/vai does not want to have smart meter installed acct# [redacted] transfer to smart meter adv Customer was not satisfied. Rights provided to customer.			
11/19/2019 14:42:38	11/19/2019	[redacted]	Yvonne L Brawley	Smart Meter Opposition
	meter tech left 3 day disconnection notice at premise, no answer at door yb Satisfied Not Applicable: Reason - Manual work			
11/18/2019 18:34:26	11/18/2019	[redacted]	Denise McDevitt	Disconnection Notice - PA Residential
	TRANSFER TO PA SMART METER ADVANCED-PA SMART METER REFUSAL-SENT 3 DAY S/O NOTICE TO METER TO WORK DKM Satisfied Not Applicable: Reason - Manual work			
11/18/2019 18:30:04	11/18/2019	[redacted]	Denise McDevitt	Meter-Other
11/11/2019 09:31:43	11/11/2019	[redacted]	Denise McDevitt	Disconnection Notice - PA Residential
	TRANSFER TO PA SMART METER ADVANCED-PA SMART METER REFUSAL-2ND CALL-3 DAY S/O NOTICE-ATTEMPTED-OUT OF SERVICE DKM Satisfied Not Applicable: Reason - Manual work			
11/08/2019 16:09:15	11/08/2019	[redacted]	Denise McDevitt	Disconnection Notice - PA Residential
	TRANSFER TO PA SMART METER ADVANCED-PA SMART METER REFUSAL-3 DAY S/O NOTICE-OUT OF SERVICE DKM Satisfied Not Applicable: Reason - Manual work			
10/29/2019 08:09:49	10/29/2019	[redacted]	Darla Sanders	Pre-disconnection Warning Letter - PA/NY
	TRANSFER TO PA SMART METER ADVANCED PA SMART METER REFUSAL - MAILED 10 DAY SHUT OFF NOTICE DS Satisfied Not Applicable: Reason - Manual work			
10/19/2019 07:47:23	10/18/2019	[redacted]	Darla Sanders	Pre-disconnection Warning Letter - PA/NY
	TRANSFER TO PA SMART METER ADVANCED PA			

Customer Contact History

Contact Date	Created Date	Contract Acct	Created By	Description
	SMART METER REFUSAL - MAILED 10 DAY NOTICE DS Satisfied Not Applicable: Reason - Manual work			
10/09/2019 10:30:05	10/09/2019	[redacted]	Darla Sanders	Soft Letter - PA/NY
	TRANSFER TO PA SMART METER ADVANCED PA SMART METER REFUSAL - MAILED FRIENDLY LETTER DS Satisfied Not Applicable: Reason - Manual work			
10/08/2019 15:19:52	10/08/2019	[redacted]	Denise McDevitt	Smart Meter Inquiry
	TRANSFER TO PA SMART METER ADVANCED-PA SMART METER REFUSAL-ATTEMPTED TO CALL-OUT OF SERVICE DKM Satisfied Not Applicable: Reason - Manual work			
10/06/2019 11:33:17	10/06/2019	[redacted]	Denise McDevitt	Smart Meter Opposition
	10/6/2019-SG'S LIST-ENTERED IN THE DI TRACKER DKM Satisfied Not Applicable: Reason - Manual work			
09/20/2019 08:06:35	09/20/2019	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
	RATE CATEGORY CHANGED			
06/20/2019 15:35:04	06/20/2019	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
	RATE CATEGORY CHANGED			
05/22/2019 06:04:41	05/22/2019	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
	RATE CATEGORY CHANGED			
03/21/2019 06:05:09	03/21/2019	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
	RATE CATEGORY CHANGED			
12/21/2018 06:05:22	12/21/2018	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
	RATE CATEGORY CHANGED			
09/20/2018 06:04:01	09/20/2018	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
	RATE CATEGORY CHANGED			
06/21/2018 12:00:55	06/21/2018	[redacted]	CS General Purpose Batch	Data Change Request (Accepted)
	RATE CATEGORY CHANGED			
04/20/2018 15:16:43	04/20/2018	[redacted]	Wendy Hines	Smart Meter Refusal - Health Threat
	042018- DONNA KOLLMAR SPOUSE CALLED - STATING MEDICAL CONCERN IN THE HOME DOES NOT WANT HARMFUL METER REQUESTING WE INSTALL THE LESS HARMFUL OF THE 2 METERS AVAILABLE - TRIED TO PROVIDE TALKING POINTS - SHE DECLINED STATING OUT INFO IS FALSE - SET REFUSAL FLAG - ADVISED INSTALL HAS BEEN PUT ON HOLD Customer was satisfied.			
04/20/2018 15:15:10	04/20/2018	[redacted]	Wendy Hines	Installation Changed
	S/W DONNA KOLLMAR - SPOUSE - DUE MEDICAL ISSUES WANTS TO OPT OUT OF SMART METER REQUESTING INSTALLATION OF ONE THAT IS LEAST HARMFUL SET SMART METER REFUSAL FLAG			
03/29/2018 01:15:12	03/29/2018	[redacted]	CS General Purpose Batch	West Penn Power Consolidated Bill Enroll Letter
03/28/2018 12:00:25	03/28/2018	[redacted]	CS General Purpose Batch	Enrollment Request (Accepted)
10/02/2017 15:22:51	10/02/2017	[redacted]	Destiny Jett	Street Light-Out
	Satisfied Not Applicable: Reason - Other - not verified			
11/11/2015 04:04:13	11/11/2015	[redacted]	CS General Purpose Batch	Enrolled in Repair Plan
	11/10/2015 : Exterior Electric Repair Protection monthly charge: $ 5.99 / month SD doc.number: 40238929			
11/19/2014 19:45:11	11/19/2014	[redacted]	EAILOGINWM6	Outbound Callback About Trouble Inquiry
	Call Result - SRC_ANS_LIVE			

Customer Contact History

Contact Date	Created Date	Contract Acct	Created By	Description
Customer reports Power is on.				
11/19/2014 19:20:40	11/19/2014	[redacted]	EAILOGINWM6	Lights-None
Played POWERONDESC: 09 We are aware of your outage and we ar e investigating the cause ERT: 11/19/14 09:00 PM				
10/30/2014 19:39:40	10/30/2014	[redacted]	CS General Purpose Batch	LPC Assessed - Special Rules
C/A: [redacted] LPC assessed based on special rules. Open editor for details. LPC on invoicing items: Due Date Item Description Amount Clear Date 20141022 Consumption Billing Debit 44.04 20141027 Total Base Amount: 44.04 LPC: 0.55 = 44.04 * 1.25 %				
10/12/2013 14:19:48	10/12/2013	[redacted]	Christopher Premo	Lights-None
Customer was satisfied.				
03/02/2012 12:45:45	03/31/2012		C11456	General Inquiry
TEXT 1: Mrs Kollmer does not want to participate in Smart Meter Program at any point. Wants it noted. Gregory Kollmar TEXT 2: 13613026602501 724-337-7340 1749,FREEPORT RD Arnold Pa. ACTIVITY : Viewed Contact Management ACCOUNT : 13613026602501 CONTACT_TYPE: Inbound Call REASON : Account Maintenance CONTACT_NAME : KOLLMAR,mrs CSR : Robey Bridgitte				
03/02/2012 12:39:08	03/31/2012		C11456	General Inquiry
ACTIVITY : No Answer ACTIVITY : Reviewed Usage History ACTIVITY : Viewed Contact Management ACCOUNT : 13613026602501 CONTACT_TYPE: Inbound Call REASON : Incomplete Call CONTACT_NAME : screen pop CSR : Kerns Victoria				
03/02/2012 12:24:00	03/31/2012		C11456	General Inquiry
ACCOUNT : 13613026602501 CONTACT_TYPE: IVR REASON : Other CSR : IVR				

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TITLE 66
PUBLIC UTILITIES

PART I. PUBLIC UTILITY CODE

SUBPART A. PRELIMINARY PROVISIONS

Chapter 28. Restructuring of Electric Utility Industry

CHAPTER 28
RESTRUCTURING OF ELECTRIC UTILITY INDUSTRY

Sec.
2801. Short title of chapter.
2802. Declaration of policy.
2803. Definitions.
2804. Standards for restructuring of electric industry.
2805. Regionalism and reciprocity.
2806. Implementation, pilot programs and performance-based rates.
2806.1. Energy efficiency and conservation program.
2806.2. Energy efficiency and conservation.
2807. Duties of electric distribution companies.
2808. Competitive transition charge.
2809. Requirements for electric generation suppliers.
2810. Revenue-neutral reconciliation.
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2812. Approval of transition bonds.
2813. Procurement of power.
2814. Additional alternative energy sources.
2815. Carbon dioxide sequestration network.

Enactment. Chapter 28 was added December 3, 1996, P.L.802, No.138, effective January 1, 1997.

§ 2801. Short title of chapter.

This chapter shall be known and may be cited as the Electricity Generation Customer Choice and Competition Act.

§ 2802. Declaration of policy.

The General Assembly finds and declares as follows:

(1) Over the past 20 years, the Federal Government and State government have introduced competition in several industries that previously had been regulated as natural monopolies.

(2) Many state governments are implementing or studying policies that would create a competitive market for the generation of electricity.

(3) Because of advances in electric generation technology and Federal initiatives to encourage greater competition in the wholesale electric market, it is now in the public interest to permit retail customers to obtain direct access to a competitive generation market as long as safe and affordable transmission and distribution service is available at levels of reliability that are currently enjoyed by the citizens and businesses of this Commonwealth.

(4) Rates for electricity in this Commonwealth are on average higher than the national average, and significant differences exist among the rates of Pennsylvania electric utilities.

(5) Competitive market forces are more effective than economic regulation in controlling the cost of generating electricity.

(6) The cost of electricity is an important factor in decisions made by businesses concerning locating, expanding and retaining facilities in this Commonwealth.

(7) This Commonwealth must begin the transition from regulation to greater competition in the electricity generation market to benefit all classes of customers and to protect this Commonwealth's ability to compete in the national and international marketplace for industry and jobs.

(8) In moving toward greater competition in the electricity generation market, the Commonwealth must resolve certain transitional issues in a manner that is fair to customers, electric utilities, investors, the employees of electric utilities, local communities, nonutility generators of electricity and other affected parties.

(9) Electric service is essential to the health and well-being of residents, to public safety and to orderly economic development, and electric service should be available to all customers on reasonable terms and conditions.

(10) The Commonwealth must, at a minimum, continue the protections, policies and services that now assist customers who are low-income to afford electric service.

(11) In order to ensure the safety and reliability of the electric system, ensure the continued provision of high-quality customer service and avoid economic dislocation, utilities shall consider the experience and expertise of their work force in moving towards competition.

(12) The purpose of this chapter is to modify existing legislation and regulations and to establish standards and procedures in order to create direct access by retail

customers to the competitive market for the generation of electricity while maintaining the safety and reliability of the electric system for all parties. Reliable electric service is of the utmost importance to the health, safety and welfare of the citizens of the Commonwealth. Electric industry restructuring should ensure the reliability of the interconnected electric system by maintaining the efficiency of the transmission and distribution system.

(13) Under current law and regulation there exists some competition in the wholesale market for the generation of electricity, but the generation, transmission, distribution and retail sale of electricity is provided generally by public utilities under bundled rates regulated by the commission. The procedures established under this chapter provide for a fair and orderly transition from the current regulated structure to a structure under which retail customers will have direct access to a competitive market for the generation and sale or purchase of electricity.

(14) This chapter requires electric utilities to unbundle their rates and services and to provide open access over their transmission and distribution systems to allow competitive suppliers to generate and sell electricity directly to consumers in this Commonwealth. The generation of electricity will no longer be regulated as a public utility function except as otherwise provided for in this chapter. Electric generation suppliers will be required to obtain licenses, demonstrate financial responsibility and comply with such other requirements concerning service as the commission deems necessary for the protection of the public.

(15) In establishing the standards for the transition to and creation of a competitive electric market, heretofore, public utilities generally have had an obligation to serve customers within their defined service territories; consistent with that obligation, have undertaken long-term investments in generation, transmission and distribution facilities in order to meet the needs of their customers; and have entered into long-term power supply agreements as required by Federal law. In many instances, these investments and agreements have created costs which may not be recoverable in a competitive market. The commission is empowered under this chapter to determine the level of transition or stranded costs for each electric utility and to provide a mechanism, the competitive transition charge, for recovery of an appropriate amount of such costs in accordance with the standards established in this chapter.

(16) It is in the public interest for the transmission and distribution of electricity to continue to be regulated as a natural monopoly subject to the jurisdiction and active supervision of the commission. Electric distribution companies should continue to be the provider of last resort in order to ensure the availability of universal electric service in this Commonwealth unless another provider of last resort is approved by the commission.

(17) There are certain public purpose costs, including programs for low-income assistance, energy conservation and others, which have been implemented and supported by public utilities' bundled rates. The public purpose is to be promoted by continuing universal service and energy conservation

policies, protections and services, and full recovery of such costs is to be permitted through a nonbypassable rate mechanism.

(18) There are certain changes to a utility which will create transition costs to accomplish the move to a competitive market. These changes may entail the closure of facilities or reduction in employee levels. If such actions are to be undertaken, the utility must fully inform the commission of the impact of such decisions on local communities and on social services and of any tax implications of the actions. The utility is expected to discuss the transition to competition with its employees or their certified representatives and may provide severance, retraining, early retirement and outplacement services. Such transition costs may be recoverable under the competitive transition charge in section 2808 (relating to competitive transition charge).

(19) All participants in the restructured electric industry are encouraged to coordinate their plans and transactions through an independent system operator or its functional equivalent.

(20) Since continuing and ensuring the reliability of electric service depends on adequate generation and on conscientious inspection and maintenance of transmission and distribution systems, the independent system operator or its functional equivalent should set, and the commission shall set through regulations, inspection, maintenance, repair and replacement standards and enforce those standards.

(21) Under Federal and State clean air laws and regulations, electricity generators located in states to the west and south of this Commonwealth are not subject to requirements as stringent as those which apply to generators and other "persons" as defined in section 3 of the act of January 8, 1960 (1959 P.L.2119, No.787), known as the Air Pollution Control Act, operating in this Commonwealth and that different regions within this Commonwealth are subject to varying air emission requirements. Under some scenarios, competition among electricity generators located in different states and different regions within this Commonwealth could make it more difficult for areas in this Commonwealth to demonstrate attainment with Federal and State air quality standards. Since this result may be caused by the disparate requirements imposed by Federal and State law on generators and other "persons" as defined in section 3 of the Air Pollution Control Act in this Commonwealth and generators located in other states, the General Assembly supports changes to Federal clean air laws and regulations that will protect Pennsylvania's environment and ensure that electricity generators and other "persons" as defined in section 3 of the Air Pollution Control Act located in this Commonwealth are not placed at an undue competitive disadvantage. The commission will consult with the Department of Environmental Protection regarding this issue during the transition to retail competition.

Cross References. Section 2802 is referred to in section 2806 of this title.

§ 2803. Definitions.

The following words and phrases when used in this chapter shall have the meanings given to them in this section unless the context clearly indicates otherwise:

"Aggregator" or **"market aggregator."** An entity, licensed by the commission, that purchases electric energy and takes title to electric energy as an intermediary for sale to retail customers.

"Bilateral contract." An agreement, as approved by the commission, reached by two parties, each acting in its own independent self-interest, as a result of negotiations free of undue influence, duress or favoritism, in which the electric energy supplier agrees to sell and the electric distribution company agrees to buy a quantity of electric energy at a specified price for a specified period of time under terms agreed to by both parties, and which follows a standard industry template widely accepted in the industry or variations thereto accepted by the parties. Standard industry templates may include the EEI Master Agreement for physical energy purchases and sales and the ISDA Master Agreement for financial energy purchases and sales.

"Broker" or **"marketer."** An entity, licensed by the commission, that acts as an agent or intermediary in the sale and purchase of electric energy but that does not take title to electric energy.

"Competitive transition charge." A nonbypassable charge applied to the bill of every customer accessing the transmission or distribution network which (charge) is designed to recover an electric utility's transition or stranded costs as determined by the commission under sections 2804 (relating to standards for restructuring of electric industry) and 2808 (relating to competitive transition charge).

"Consumer." A retail electric customer.

"Customer." A retail electric customer.

"Default service provider." An electric distribution company within its certified service territory or an alternative supplier approved by the commission that provides generation service to retail electric customers who:

(1) contract for electric power, including energy and capacity, and the chosen electric generation supplier does not supply the service; or

(2) do not choose an alternative electric generation supplier.

"Direct access." The right of electric generation suppliers and end-use customers to utilize and interconnect with the electric transmission and distribution system on a nondiscriminatory basis at rates, terms and conditions of service comparable to the transmission and distribution companies' own use of the system to transport electricity from any generator of electricity to any end-use customer.

"Electric distribution company." The public utility providing facilities for the jurisdictional transmission and distribution of electricity to retail customers, except building or facility owners/operators that manage the internal distribution system serving such building or facility and that supply electric power and other related electric power services to occupants of the building or facility.

"Electric generation supplier" or **"electricity supplier."** A person or corporation, including municipal corporations which choose to provide service outside their municipal limits except to the extent provided prior to the effective date of this chapter, brokers and marketers, aggregators or any other entities, that sells to end-use customers electricity or related services utilizing the jurisdictional transmission or distribution facilities of an electric distribution company or that purchases, brokers, arranges or markets electricity or related services for sale to end-use customers utilizing the jurisdictional transmission and distribution facilities of an electric distribution company. The term excludes building or facility owner/operators that manage the internal distribution system serving such building or facility and that supply electric power and other related power services to occupants of the building or facility. The term excludes electric cooperative corporations except as provided in 15 Pa.C.S. Ch. 74 (relating to generation choice for customers of electric cooperatives).

"End-use customer." A retail electric customer.

"Reliability." Includes adequacy and security. As used in this definition, "adequacy" means the provision of sufficient generation, transmission and distribution capacity so as to supply the aggregate electric power and energy requirements of consumers, taking into account scheduled and unscheduled outages of system facilities; and "security" means designing, maintaining and operating a system so that it can handle emergencies safely while continuing to operate.

"Renewable resource." Includes technologies such as solar photovoltaic energy, solar thermal energy, wind power, low-head hydropower, geothermal energy, landfill and mine-based methane gas, energy from waste and sustainable biomass energy.

"Retail customer." A retail electric customer.

"Retail electric customer." A direct purchaser of electric power. The term excludes an occupant of a building or facility where the owners/operators manage the internal distribution system serving such building or facility and supply electric power and other related power services to occupants of the building or facility; where such owners/operators are direct purchasers of electric power; and where the occupants are not direct purchasers.

"Transition or stranded costs." An electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the commission determines will remain following mitigation by the electric utility. This term includes:

(1) Regulatory assets and other deferred charges typically recoverable under current regulatory practice, the unfunded portion of the utility's projected nuclear generating plant decommissioning costs and cost obligations under contracts with nonutility generating projects which have received a commission order, the recoverability of which shall be determined under section 2808(c)(1) (relating to competitive transition charge).

(2) Prudently incurred costs related to cancellation, buyout, buydown or renegotiation of nonutility generating projects consistent with section 527 (relating to cogeneration rules and regulations), the recoverability of which shall be determined pursuant to section 2808(c)(2).

(3) The following costs, the recoverability of which shall be determined pursuant to section 2808(c)(3):

(i) Net plant investments and costs attributable to the utility's existing generation plants and facilities.

(ii) The utility's disposal of spent nuclear fuel.

(iii) The utility's long-term purchase power commitments other than the costs defined in paragraphs (1) and (2).

(iv) Retirement costs attributable to the utility's existing generating plants other than the costs defined in paragraph (1).

(v) Other transition costs of the utility, including costs of employee severance, retraining, early retirement, outplacement and related expenses, at reasonable levels, for employees who are affected by changes that occur as a result of the restructuring of the electric industry occasioned by this chapter.

The term includes any costs attributable to physical plants no longer used and useful because of the transition to retail competition. The term excludes any amounts previously disallowed by the commission as imprudently incurred. To the extent that the recoverability of amounts that are sought to be included as transition or stranded costs are subject to appellate review as of the time of the commission determination, any determination to include such costs shall be reversed to the extent required by the results of that appellate review.

"Transmission and distribution costs." All costs directly or indirectly incurred to provide transmission and distribution services to retail electric customers. This includes the return of and return on facilities and other capital investments necessary to provide transmission and distribution services and associated operating expenses, including applicable taxes.

"Universal service and energy conservation." Policies, protections and services that help low-income customers to maintain electric service. The term includes customer assistance programs, termination of service protection and policies and services that help low-income customers to reduce or manage energy consumption in a cost-effective manner, such as the low-income usage reduction programs, application of renewable resources and consumer education.

(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added the defs. of "bilateral contract" and "default service provider." See the preamble to Act 129 of 2008 in the appendix to this title for special provisions relating to legislative findings and declarations.

References in Text. Chapter 74 of Title 15, referred to in the def. of "electric generation supplier" or "electricity supplier," is expired.

Cross References. Section 2803 is referred to in section 1403 of this title.

§ 2804. Standards for restructuring of electric industry.

The following interdependent standards shall govern the commission's assessment and approval of each public utility's restructuring plan, oversight of the transition process and regulation of the restructured electric utility industry:

(1) The commission shall ensure continuation of safe and reliable electric service to all consumers in the Commonwealth, including:

(i) The maintenance of adequate reserve margins by electric suppliers in conformity with the standards required by the North American Electric Reliability Council (NERC) and the regional reliability council appropriate to each supplier, or any successors to those reliability entities, and in conformity with established industry standards and practices.

(ii) The installation and maintenance of transmission and distribution facilities in conformity with established industry standards and practices, including the standards set forth in the National Electric Safety Code.

(2) Consistent with the time line set forth in section 2806 (relating to implementation, pilot programs and performance-based rates), the commission shall allow customers to choose among electric generation suppliers in a competitive generation market through direct access. Customers should be able to choose among alternatives such as firm and interruptible service, flexible pricing and alternate generation sources, including reasonable and fair opportunities to self-generate and interconnect. These alternatives may be provided by different electric generation suppliers.

(3) The commission shall require the unbundling of electric utility services, tariffs and customer bills to separate the charges for generation, transmission and distribution. The commission may require the unbundling of other services.

(4) The following caps on electric utility rates shall apply:

(i) For a period of 54 months from the effective date of this chapter or until an electric distribution utility is no longer recovering its transition or stranded costs through a competitive transition charge or intangible transition charge and all the customers of an electric distribution utility can choose an alternative provider of electric generation, whichever is shorter:

(A) the total charges of an electric distribution utility for service to any customer who purchases generation from that utility shall not exceed the total charges that have been approved by the commission for such service as of the effective date of this chapter; and

(B) for customers who purchase generation from a supplier other than the electric distribution utility, the charges of the utility for non-generation services that are regulated as of the effective date of this chapter, exclusive of the competitive transition charge and intangible transition charge, shall not exceed the non-generation charges that have been approved by the commission for such service as of the effective date of this chapter.

(ii) In addition to the rate cap set forth in subparagraph (i), for a period of nine years from the effective date of this chapter or until an electric distribution utility is no longer recovering its transition or stranded costs through a competitive transition charge or intangible transition charge and all customers of an electric distribution utility can choose an alternative provider of electric generation, whichever is shorter, the generation component of a utility's charges to customers who purchase generation from the utility, including the competitive transition charge and intangible transition charge, shall not exceed the generation component charged to the customers that has been approved by the commission for such service as of the effective date of this chapter.

(iii) An electric distribution utility may seek, and the commission may approve, an exception to the limitations set forth in subparagraphs (i) and (ii) only in any of the following circumstances:

(A) The electric distribution utility meets the requirements for extraordinary rate relief under section 1308(e) (relating to voluntary changes in rates).

(B) Either the electric distribution utility is required to begin payment under contracts with nonutility generation projects that have received commission orders, has been unable to mitigate such costs, such costs are not recoverable in a competitive generation market and such costs were not previously covered in the competitive transition charge or intangible transition charge, or the utility prudently incurs costs related to cancellation, buyout, buydown or renegotiation of nonutility generating project obligations of the utility consistent with section 527 (relating to cogeneration rules and regulations) and such costs were not previously covered in the competitive transition charge or intangible transition charge. Costs related to cancellation, buyout, buydown or renegotiation shall be recovered from ratepayers over a period not to exceed three years, unless the commission determines within its discretion to require a longer recovery period due to the magnitude of such costs, but shall be accounted for by the utility on a levelized basis over the total period in which the generation portion of the utility's rates are capped.

(C) The electric distribution utility is subject to significant increases in the rates of Federal or State taxes or other significant changes in law or regulations that would not allow the utility to earn a fair rate of return.

(D) The electric distribution utility is subject to significant increases in the unit rate of fuel for utility generation or the price of purchased power that are outside of the control of the utility and that would not allow the utility to earn a fair rate of return.

(E) The electric distribution utility is directed by the commission or an independent system operator or its functional equivalent to make expenditures to repair or upgrade its transmission or distribution system.

(F) The electric distribution utility seeks to increase its allowance for nuclear decommissioning costs to reflect new information not available at the time the utility's existing rates were determined, and such costs are not recoverable in the competitive generation market and are not covered in the competitive transition charge or intangible transition charge, and such costs would not allow the utility to earn a fair rate of return.

(G) As permitted by paragraph (16).

(iv) Consistent with the requirements of due process, the commission may expedite proceedings that invoke the provisions of subparagraph (iii).

(v) If an electric distribution utility rolls its energy cost rate into base rates at a combined level that does not exceed its combined level of such rates which have been approved by the commission as of the effective date of this chapter, the utility shall not be required to reduce its capped rates below the capped level upon the complaint of any party if the commission determines that any excess earnings achieved under the cap are being utilized to mitigate transition or stranded costs for the benefit of ratepayers or to offset other known and measurable cost increases that would be recoverable under traditional ratemaking but are not included within the capped rates.

(vi) This paragraph shall not apply to new services offered for the first time after the effective date of this chapter.

(5) The commission may permit, but shall not require, an electric utility to divest itself of facilities or to reorganize its corporate structure.

(6) Consistent with the provision of section 2806, the commission shall require that a public utility that owns or operates jurisdictional transmission and distribution facilities shall provide transmission and distribution service to all retail electric customers in their service territory and to electric cooperative corporations and electric generation suppliers, affiliated or nonaffiliated, on rates, terms of access and conditions that are comparable to the utility's own use of its system.

(7) The commission shall require that restructuring of the electric utility industry be implemented in a manner that does not unreasonably discriminate against one customer class to the benefit of another.

(8) The commission shall establish for each electric utility an appropriate cost-recovery mechanism which is designed to fully recover the electric utility's universal service and energy conservation costs over the life of these programs.

(9) The commission shall ensure that universal service and energy conservation policies, activities and services are appropriately funded and available in each electric distribution territory. Policies, activities and services under this paragraph shall be funded in each electric distribution territory by nonbypassable, competitively neutral cost-recovery mechanisms that fully recover the costs of universal service and energy conservation services. The

commission shall encourage the use of community-based organizations that have the necessary technical and administrative experience to be the direct providers of services or programs which reduce energy consumption or otherwise assist low-income customers to afford electric service. Programs under this paragraph shall be subject to the administrative oversight of the commission which will ensure that the programs are operated in a cost-effective manner.

(10) The commission shall establish rates for jurisdictional transmission and distribution services and shall continue to regulate distribution services for new and existing customers in accordance with this chapter and Chapter 13 (relating to rates and rate making).

(11) The time line for the transition to and phase-in of direct access to competitive electric generation shall be in accordance with section 2806.

(12) The commission has the authority to order utility participation in retail access pilot programs as set forth in section 2806 and as further implemented or modified by the commission, with direct access to begin on April 1, 1997. The commission shall conduct milestone reviews of the transition to retail electric generation competition to assure a technically workable and equitable transition period.

(13) Consistent with section 2808 (relating to competitive transition charge), the commission has the power and duty to approve a competitive transition charge for the recovery of transition or stranded costs it determines to be just and reasonable to recover from ratepayers.

(14) The transition to a competitive generation market shall be orderly, protect electric system reliability, be fair to ratepayers and provide the investors in Pennsylvania electric utilities with a fair opportunity to fully recover the amount of transition or stranded costs that the commission determines to be just and reasonable.

(15) At the time each utility files its restructuring plan with the commission, the utility shall submit an initial plan that sets forth how it shall meet its universal service and energy conservation obligations.

(16) The following shall apply:

(i) The commission shall issue regulations that permit the electric distribution company to recover any change in its State tax liability under sections 2806(h), 2809(c) (relating to requirements for electric generation suppliers) and 2810 (relating to revenue-neutral reconciliation) or in its liability under 52 Pa. Code §§ 69.51 through 69.56 (relating to inclusion of State taxes and gross receipts taxes in base rates) to the extent that the resulting rate does not exceed the rate cap established in this section except as provided in this chapter.

(ii) With regard to any portion of the change in an electric distribution company's tax liability under section 2810 which would cause it to exceed the rate cap, the electric distribution company may file a single issue rate proceeding under section 1308(a) to recover that amount. The commission shall adjudicate, within 60 days, whether the resulting rates are just and reasonable.

(iii) With regard to any portion of the change in an electric distribution company's tax liability under sections 2806(h) and 2809(c) which would cause it to exceed the price cap, upon certification to the commission by affidavit that the electric distribution company has not collected the taxes due pursuant to the tariff indemnification provisions required by section 2810(m) and that the electric distribution company and the Department of Revenue have not collected the taxes due pursuant to the other means set forth in sections 2806(g)(3)(i) and (ii) and 2809(c) to recover the taxes due and any interest thereon, the electric distribution utility shall be permitted to recover that amount in the State Tax Adjustment Surcharge.

Cross References. Section 2804 is referred to in sections 2803, 2806, 2807, 2812 of this title.

§ 2805. Regionalism and reciprocity.

(a) Other states.--The commission shall take all necessary and appropriate steps to encourage interstate power pools to enhance competition and to complement industry restructuring on a regional basis. The Commonwealth, the commission and Pennsylvania electric utilities shall work with the Federal Government, other states in the region and interstate power pools to accomplish the goals of restructuring and to establish independent system operators or their functional equivalents to operate the transmission system and interstate power pools. The commission, Pennsylvania electric utilities and all electricity suppliers shall work with the Federal Government, other states in the region, the North American Electric Reliability Council and its regional coordinating councils or their successors, interstate power pools, and with the independent system operator or its functional equivalent to ensure the continued provision of adequate, safe and reliable electric service to the citizens and businesses of this Commonwealth.

(b) Electric cooperatives, municipalities and other electric generation suppliers.--

(1) In order to make the benefits of competition in the generation and sale of electricity as widely available as possible to retail customers and to provide open, fair and nondiscriminatory access to all electric generation suppliers:

(i) Consistent with 15 Pa.C.S. Ch. 74 (relating to generation choice for customers of electric cooperatives), no electric cooperative or municipality which distributes electricity to end-use customers may utilize the transmission or distribution system of an electric utility regulated by the commission for the purpose of supplying electricity to an end-use customer unless the electric cooperative or municipality provides open and nondiscriminatory access and allows other electric generation suppliers to utilize its facilities, including any facilities it is entitled to provide to third parties pursuant to contract, to make sales to the end-use customers it serves. A borough may prohibit electric generation suppliers from serving end-use customers within its borough limits; however, such a borough shall be prohibited from providing generation service to end-use customers outside of its borough limits which it did not serve prior to the effective date of this chapter.

(ii) The commission shall require any electric cooperative seeking a certificate under 15 Pa.C.S. Ch. 74 to provide open and nondiscriminatory access to its transmission and distribution facilities as a condition to the granting of the certificate.

(iii) The reliability of the transmission service provided to electric cooperative corporations must be comparable to the reliability which the transmission supplier provides at the wholesale level.

(2) No electric utility regulated by the commission and no affiliate of such electric utility may use the distribution system of another electric utility regulated by the commission or make sales to end-use customers in another electric utility's service territory unless the commission has approved a restructuring plan for the supplying electric utility which provides for direct access comparable to the direct access provided under the approved plan of the electric utility operating the distribution system in the location where the supplying electric utility seeks to sell electricity to an end-use customer. No electric utility regulated by the commission and no affiliate of such electric utility may use the distribution system of an electric cooperative corporation or make sales to end-use customers in the territory of an electric cooperative corporation unless the commission has approved a restructuring plan for the supplying electric utility.

References in Text. Chapter 74 of Title 15, referred to in subsec. (b), is expired.

§ 2806. Implementation, pilot programs and performance-based rates.

(a) General rule.--The generation of electricity shall no longer be regulated as a public utility service or function except as otherwise provided for in this chapter at the conclusion of a transition and phase-in period beginning on the effective date of this chapter and ending, consistent with the commission's discretion under this section, January 1, 2001. As of January 1, 2001, consistent with the commission's discretion under this section, all customers of electric distribution companies in this Commonwealth shall have the opportunity to purchase electricity from their choice of electric generation suppliers. The ultimate choice of the electric generation supplier is to rest with the consumer.

(b) Schedule.--Recognizing that approximately 5% of the peak load will have retail access through pilot programs, the following schedule for phased implementation of retail access shall be adhered to unless a determination is made by the commission under subsection (c):

(1) As of January 1, 1999, a maximum of 33% of the peak load of each customer class shall have the opportunity for direct access.

(2) As of January 1, 2000, a maximum of 66% of the peak load of each customer class shall have the opportunity for direct access.

(3) As of January 1, 2001, all customers of electric distribution companies in this Commonwealth shall have the opportunity for direct access.

(4) The commission shall establish regulations specifying that, within each customer class, the customers that are eligible for direct access prior to full direct access shall be determined on a first-come-first-served basis unless otherwise determined by the commission through regulation, in the context of restructuring plans, or in other appropriate administrative proceedings, to prevent competitive disadvantages among similarly situated customers within a customer class.

(c) Additional time.--

(1) The commission may determine that an additional six-month transition period is necessary prior to the January 1, 1999, implementation date. A determination under this subsection must be made at least 45 days in advance of the scheduled date for implementation and must be based on one or more of the following considerations:

(i) Implementation would materially affect the reliability of the electric system.

(ii) Federal approvals necessary for the implementation of the provisions of this chapter have not been granted.

(iii) Communications and information systems necessary for the implementation of retail access have not been installed for reasons beyond the utility's control, as measured by appropriate industry standards.

(iv) Pennsylvania generators would be disadvantaged due to lack of regional reciprocity with respect to direct access.

(v) The interests of Pennsylvania consumers and the competitive position of Pennsylvania business and industry would be materially affected.

(vi) Such other consideration as would materially affect the orderly implementation of the legislative purpose of this chapter under section 2802(12) through (21) (relating to declaration of policy).

(2) Consistent with the considerations listed in paragraph (1), the commission may determine that an additional six-month transition period is necessary. This determination must be made by the commission by May 15, 1999.

(d) Filing of restructuring plans.--All electric utilities in this Commonwealth shall submit to the commission, pursuant to a schedule to be determined by the commission in consultation with the electric utilities, beginning on April 1, 1997, but in no event later than September 30, 1997, a restructuring plan to implement direct access to a competitive market for the generation of electricity.

(e) Contents of restructuring plans.--A restructuring plan under subsection (d) must include, consistent with the determinations of the commission, unbundled prices or rates for generation, jurisdictional transmission, distribution and other services; a proposed competitive transition charge; a proposed universal service and energy conservation cost-recovery mechanism; procedures for ensuring direct access to all licensed electric generation suppliers; a discussion of the impacts of the proposed plan on the utility's employees; and revised tariffs and rate schedules implementing the above.

(f) Commission review.--The commission shall review the restructuring plan filed by each electric utility and shall, after open evidentiary hearings with proper notice and opportunity for all parties to cross-examine witnesses, issue an order accepting, modifying or rejecting such plan at the earliest date possible, but no later than nine months from the filing of such restructuring plan. If the commission rejects a restructuring plan, it shall state the specific reasons for rejection and direct the electric utility to file an alternative plan addressing these objections within 30 days of the entry date of the commission order rejecting the plan. The commission shall review the alternative plan, solicit comments from interested parties and issue a final order within 45 days of the filing of the revised plan.

(g) Retail access pilot programs.--As of the effective date of this chapter, the commission has authority to order electric utilities to submit proposals for retail access pilot programs to begin April 1, 1997. The commission shall provide guidelines for retail access pilot programs by order.

(1) In order to determine whether all customers classes can benefit from competitive markets, utilities shall tailor proposed retail access pilot programs to accommodate the specific geographic, demographic and socioeconomic characteristics of their customer base. Retail access pilot programs must include an equal opportunity for the broadest practical direct access by all customer classes to electric generation suppliers.

(2) The minimum period of time for a retail access pilot program shall be one year and shall include an evaluation process as directed by the commission.

(3) In order to ensure the safety and reliability of the generation of electricity in this Commonwealth, participation in the retail access pilot programs shall be limited to electricity suppliers subject to commission licensure or certification.

(i) Each participating electricity supplier shall do all of the following:

(A) Certify to the commission that it will pay and in subsequent years has paid the full amount of taxes imposed by Articles II and XI of the act of March 4, 1971 (P.L.6, No.2), known as the Tax Reform Code of 1971, and any tax imposed by this chapter.

(B) Provide the commission with the address of the participant's principal office in this Commonwealth or the address of the participant's registered agent in this Commonwealth, the latter being the address at which the participant may be served process.

(C) Agree that it shall be subject to all taxes imposed by the Tax Reform Code of 1971 and any tax imposed by this chapter.

(ii) Failure of an electricity supplier to pay a tax referred to in subparagraph (i) or to otherwise comply with the provisions of this paragraph shall be cause for the commission to revoke the license of the electricity supplier.

(iii) If an electricity supplier, other than an electric distribution company, does not pay the tax imposed upon gross receipts under section 1101 of the Tax Reform Code of 1971 or this chapter, the electric distribution company to whose retail customer the electricity supplier provided generation service shall remit the unpaid tax, as a tax on the use of electricity in this Commonwealth, to the Department of Revenue and may collect or seek reimbursement of the tax so paid from the electricity provider or any other appropriate party that used the electricity in this Commonwealth. The department shall collect and enforce the use tax herein provided under section 1102 of the Tax Reform Code of 1971. Failure of the electric distribution company to pay the amount within 30 days after notice provided by the department shall cause interest to be imposed on the electric distribution company in accordance with Article XI of the Tax Reform Code of 1971. Interest shall be calculated from the 31st day after the department gives the notice required in this subparagraph. An electric distribution company or other appropriate person may challenge the imposition of the tax and interest by filing a petition with the department not later than 30 days after the date on which the tax became due.

(4) The percentage of utility load committed to a retail access pilot program must be approximately 5% of utility's peak load for each customer class. Waivers of this condition may be considered by the commission for economic development purposes or special circumstances.

(h) Flexible pricing.--In addition to the implicit authority of the commission under section 501 (relating to general powers), the commission has the authority to approve flexible pricing and flexible rates, including negotiated, contract-based tariffs designed to meet the specific needs of a utility customer and to address competitive alternatives.

(i) Performance-based rates and alternative regulation.--The commission has authority to use performance-based rates as an alternative to existing rate base/rate of return ratemaking, subject to the restrictions pertaining to rate caps in section 2804(4) (relating to standards for restructuring of electric industry).

Cross References. Section 2806 is referred to in sections 2804, 2807, 2810, 2812 of this title.

§ 2806.1. Energy efficiency and conservation program.

(a) Program.--The commission shall, by January 15, 2009, adopt an energy efficiency and conservation program to require electric distribution companies to adopt and implement cost-effective energy efficiency and conservation plans to reduce energy demand and consumption within the service territory of each electric distribution company in this Commonwealth. The program shall include:

(1) Procedures for the approval of plans submitted under subsection (b).

(2) An evaluation process, including a process to monitor and verify data collection, quality assurance and results of each plan and the program.

(3) An analysis of the cost and benefit of each plan submitted under subsection (b) in accordance with a total resource cost test approved by the commission.

(4) An analysis of how the program and individual plans will enable each electric distribution company to achieve or exceed the requirements for reduction in consumption under subsections (c) and (d).

(5) Standards to ensure that each plan includes a variety of energy efficiency and conservation measures and will provide the measures equitably to all classes of customers.

(6) Procedures to make recommendations as to additional measures that will enable an electric distribution company to improve its plan and exceed the required reductions in consumption under subsections (c) and (d).

(7) Procedures to require that electric distribution companies competitively bid all contracts with conservation service providers.

(8) Procedures to review all proposed contracts prior to the execution of the contract with conservation service providers to implement the plan. The commission may order the modification of a proposed contract to ensure that the plan meets the requirements for reduction in demand and consumption under subsections (c) and (d).

(9) Procedures to ensure compliance with requirements for reduction in consumption under subsections (c) and (d).

(10) A requirement for the participation of conservation service providers in the implementation of all or part of a plan.

(11) Cost recovery to ensure that measures approved are financed by the same customer class that will receive the direct energy and conservation benefits.

(b) Duties of electric distribution companies.--

(1) (i) By July 1, 2009, each electric distribution company shall develop and file an energy efficiency and conservation plan with the commission for approval to meet the requirements of subsection (a) and the requirements for reduction in consumption under subsections (c) and (d). The plan shall be implemented upon approval by the commission. The following are the plan requirements:

(A) The plan shall include specific proposals to implement energy efficiency and conservation measures to achieve or exceed the required reductions in consumption under subsections (c) and (d).

(B) A minimum of 10% of the required reductions in consumption under subsections (c) and (d) shall be obtained from units of Federal, State and local government, including municipalities, school districts, institutions of higher education and nonprofit entities.

(C) The plan shall explain how quality assurance and performance will be measured, verified and evaluated.

(D) The plan shall state the manner in which the plan will achieve the requirements of the program under subsection (a) and will achieve or exceed the required reductions in consumption under subsections (c) and (d).

(E) The plan shall include a contract with one or more conservation service providers selected by competitive bid to implement the plan or a portion of the plan as approved by the commission.

(F) The plan shall include estimates of the cost of implementation of the energy efficiency and conservation measures in the plan.

(G) The plan shall include specific energy efficiency measures for households at or below 150% of the Federal poverty income guidelines. The number of measures shall be proportionate to those households' share of the total energy usage in the service territory. The electric distribution company shall coordinate measures under this clause with other programs administered by the commission or another Federal or State agency. The expenditures of an electric distribution company under this clause shall be in addition to expenditures made under 52 Pa. Code Ch. 58 (relating to residential low income usage reduction programs).

(H) The plan shall include a proposed cost-recovery tariff mechanism, in accordance with section 1307 (relating to sliding scale of rates; adjustments), to fund the energy efficiency and conservation measures and to ensure full and current recovery of the prudent and reasonable costs of the plan, including administrative costs, as approved by the commission.

(I) The electric distribution company shall demonstrate that the plan is cost effective using a total resource cost test approved by the commission and provides a diverse cross section of alternatives for customers of all rate classes.

(J) The plan shall require an annual independent evaluation of its cost-effectiveness and a full review of the results of each five-year plan required under subsection (c)(3) and, to the extent practical, how the plan will be adjusted on a going-forward basis as a result of the evaluation.

(K) The plan shall include an analysis of the electric distribution company's administrative costs.

(ii) A new plan shall be filed with the commission every five years or as otherwise required by the commission. The plan shall set forth the manner in which the company will meet the required reductions in consumption under subsections (c) and (d).

(iii) No more than 2% of funds available to implement a plan under this subsection shall be allocated for experimental equipment or devices.

(2) The commission shall direct an electric distribution company to modify or terminate any part of a plan approved under this section if, after an adequate period for implementation, the commission determines that an energy efficiency or conservation measure included in the plan will not achieve the required reductions in consumption in a cost-effective manner under subsections (c) and (d).

(3) If part of a plan is modified or terminated under paragraph (2), the electric distribution company shall submit

a revised plan describing actions to be taken to offer substitute measures or to increase the availability of existing measures in the plan to achieve the required reductions in consumption under subsections (c) and (d).

(c) Reductions in consumption.--The plans adopted under subsection (b) shall reduce electric consumption as follows:

(1) By May 31, 2011, total annual weather-normalized consumption of the retail customers of each electric distribution company shall be reduced by a minimum of 1%. The 1% load reduction in consumption shall be measured against the electric distribution company's expected load as forecasted by the commission for June 1, 2009, through May 31, 2010, with provisions made for weather adjustments and extraordinary loads that the electric distribution company must serve.

(2) By May 31, 2013, the total annual weather-normalized consumption of the retail customers of each electric distribution company shall be reduced by a minimum of 3%. The 3% load reduction in consumption shall be measured against the electric distribution company's expected load as forecasted by the commission for June 1, 2009, through May 31, 2010, with provisions made for weather adjustments and extraordinary loads that the electric distribution company must serve.

(3) By November 30, 2013, and every five years thereafter, the commission shall evaluate the costs and benefits of the program established under subsection (a) and of approved energy efficiency and conservation plans submitted to the program. The evaluation shall be consistent with a total resource cost test or a cost-benefit analysis determined by the commission. If the commission determines that the benefits of the program exceed the costs, the commission shall adopt additional required incremental reductions in consumption.

(d) Peak demand.--The plans adopted under subsection (b) shall reduce electric demand as follows:

(1) By May 31, 2013, the weather-normalized demand of the retail customers of each electric distribution company shall be reduced by a minimum of 4.5% of annual system peak demand in the 100 hours of highest demand. The reduction shall be measured against the electric distribution company's peak demand for June 1, 2007, through May 31, 2008.

(2) By November 30, 2013, the commission shall compare the total costs of energy efficiency and conservation plans implemented under this section to the total savings in energy and capacity costs to retail customers in this Commonwealth or other costs determined by the commission. If the commission determines that the benefits of the plans exceed the costs, the commission shall set additional incremental requirements for reduction in peak demand for the 100 hours of greatest demand or an alternative reduction approved by the commission. Reductions in demand shall be measured from the electric distribution company's peak demand for the period from June 1, 2011, through May 31, 2012. The reductions in consumption required by the commission shall be accomplished no later than May 31, 2017.

(e) Commission approval.--

(1) The commission shall conduct a public hearing on each plan and allow for the submission of recommendations by the Office of Consumer Advocate and the Office of Small Business Advocate and by members of the public as to how the electric

distribution company could improve its plan or exceed the required reductions in consumption under subsections (c) and (d).

(2) The commission shall approve or disapprove a plan filed under subsection (b) within 120 days of submission. The following shall apply to an order disapproving a plan:

(i) The commission shall describe in detail the reasons for the disapproval.

(ii) The electric distribution company shall have 60 days to file a revised plan to address the deficiencies identified by the commission. The revised plan shall be approved or disapproved by the commission within 60 days.

(f) Penalties.--

(1) The following shall apply for failure to submit a plan:

(i) An electric distribution company that fails to file a plan under subsection (b) shall be subject to a civil penalty of $100,000 per day until the plan is filed.

(ii) An electric distribution company that fails to file a revised plan under subsection (e)(2)(ii) shall be subject to a civil penalty of $100,000 per day until the plan is filed.

(iii) Penalties collected under this paragraph shall be deposited in the low-income electric customer assistance program of the energy distribution company for the respective service territory.

(2) The following shall apply to an electric distribution company that fails to achieve the reductions in consumption required under subsection (c) or (d):

(i) The electric distribution company shall be subject to a civil penalty not less than $1,000,000 and not to exceed $20,000,000 for failure to achieve the required reductions in consumption under subsection (c) or (d). Any penalty paid by an electric distribution company under this subparagraph shall not be recoverable from ratepayers.

(ii) If an electric distribution company fails to achieve the required reductions in consumption under subsection (c) or (d), responsibility to achieve the reductions in consumption shall be transferred to the commission. The commission shall do all of the following:

(A) Implement a plan to achieve the required reductions in consumption under subsection (c) or (d).

(B) Contract with conservation service providers as necessary to implement any portion of the plan.

(g) Limitation on costs.--The total cost of any plan required under this section shall not exceed 2% of the electric distribution company's total annual revenue as of December 31, 2006. The provisions of this paragraph shall not apply to the cost of low-income usage reduction programs established under 52 Pa. Code Ch. 58 (relating to residential low income usage reduction programs).

(h) Costs.--The commission shall recover from electric distribution companies the costs of implementing the program established under this section.

(i) Report.--The following shall apply:

(1) Each electric distribution company shall submit an annual report to the commission relating to the results of the energy efficiency and conservation plan within each electric distribution service territory. The report shall include all of the following:

(i) Documentation of program expenditures.

(ii) Measurement and verification of energy savings under the plan.

(iii) Evaluation of the cost-effectiveness of expenditures.

(iv) Any other information required by the commission.

(2) Beginning five years following the effective date of this section and annually thereafter, the commission shall submit a report to the Consumer Protection and Professional Licensure Committee of the Senate and the Consumer Affairs Committee of the House of Representatives.

(j) Existing funding sources.--Each electric distribution company shall, upon request by any person, provide a list of all eligible Federal and State funding programs available to ratepayers for energy efficiency and conservation. The list shall be posted on the electric distribution company's Internet website.

(k) Recovery.--

(1) An electric distribution company shall recover on a full and current basis from customers, through a reconcilable adjustment clause under section 1307, all reasonable and prudent costs incurred in the provision or management of a plan provided under this section. This paragraph shall apply to all electric distribution companies, including electric distribution companies subject to generation or other rate caps.

(2) Except as set forth in paragraph (3), decreased revenues of an electric distribution company due to reduced energy consumption or changes in energy demand shall not be a recoverable cost under a reconcilable automatic adjustment clause.

(3) Decreased revenue and reduced energy consumption may be reflected in revenue and sales data used to calculate rates in a distribution-base rate proceeding filed by an electric distribution company under section 1308 (relating to voluntary changes in rates).

(l) Applicability.--This section shall not apply to an electric distribution company with fewer than 100,000 customers.

(m) Definitions.--As used in this section, the following words and phrases shall have the meanings given to them in this subsection:

"Conservation service provider." An entity that provides information and technical assistance on measures to enable a person to increase energy efficiency or reduce energy consumption and that has no direct or indirect ownership, partnership or other affiliated interest with an electric distribution company.

"Electric distribution company total annual revenue." Amounts paid to the electric distribution company for generation, transmission, distribution and surcharges by retail customers.

"Energy efficiency and conservation measures."

(1) Technologies, management practices or other measures employed by retail customers that reduce electricity consumption or demand if all of the following apply:

(i) The technology, practice or other measure is installed on or after the effective date of this section at the location of a retail customer.

(ii) The technology, practice or other measure reduces consumption of energy or peak load by the retail customer.

(iii) The cost of the acquisition or installation of the measure is directly incurred in whole or in part by the electric distribution company.

(2) Energy efficiency and conservation measures shall include solar or solar photovoltaic panels, energy efficient windows and doors, energy efficient lighting, including exit sign retrofit, high bay fluorescent retrofit and pedestrian and traffic signal conversion, geothermal heating, insulation, air sealing, reflective roof coatings, energy efficient heating and cooling equipment or systems and energy efficient appliances and other technologies, practices or measures approved by the commission.

"Peak demand." The highest electrical requirement occurring during a specified period. For an electric distribution company, the term shall mean the sum of the metered consumption for all retail customers over that period.

"Quality assurance." All of the following:

(1) The auditing of buildings, equipment and processes to determine the cost-effectiveness of energy efficiency and conservation measures using nationally recognized tools and certification programs.

(2) Independent inspection of completed energy efficiency and conservation measures completed by third-party entities to evaluate the quality of the completed measure.

"Real-time price." A rate that directly reflects the different cost of energy during each hour.

"Time-of-use rate." A rate that reflects the costs of serving customers during different time periods, including off-peak and on-peak periods, but not as frequently as each hour.

"Total resource cost test." A standard test that is met if, over the effective life of each plan not to exceed 15 years, the net present value of the avoided monetary cost of supplying electricity is greater than the net present value of the monetary cost of energy efficiency conservation measures.

(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added section 2806.1. See the preamble to Act 129 of 2008 in the appendix to this title for special provisions relating to legislative findings and declarations.

§ 2806.2. Energy efficiency and conservation.

(a) Registry.--The commission shall, by March 1, 2009, establish a registry of approved persons qualified to provide conservation services to all classes of customers. In order to be included in the registry, a conservation service provider must meet experience and other qualifications determined by the commission.

(b) Application.--The commission shall develop an application for registration under subsection (a) and may charge a reasonable registration fee.

(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added section 2806.2. See the preamble to Act 129 of 2008 in the appendix to this title for special provisions relating to legislative findings and declarations.

§ 2807. Duties of electric distribution companies.

(a) General rule.--Each electric distribution company shall maintain the integrity of the distribution system at least in conformity with the National Electric Safety Code and such other standards practiced by the industry in a manner sufficient to provide safe and reliable service to all customers connected to the system consistent with this title and the commission's regulations. In performing such duties, the electric distribution company shall implement procedures to require all electric generation suppliers to deliver energy to the electric distribution company at locations and in amounts which are adequate to meet the energy supplier's obligations to its customers. Subject to commission approval, the electric distribution company may require that the customer install, at the customer's expense, enhanced metering capability sufficient to match the energy delivered by the electric generation suppliers with consumption by the customer.

(b) Procedures for review by the commission.--There shall be a rebuttable presumption that the electric distribution company has the ability to receive energy at all points on its system sufficient to meet the needs of all electric generation suppliers' customers on its system. The electric distribution company shall not have an obligation to install nonstandard facilities, either as to type or location, for the purpose of receiving energy from the energy supplier unless the energy supplier or its customer pays the full cost of these facilities. Nothing in this chapter shall prevent the electric distribution company from upgrading its system to meet changing customer requirements consistent with the requirements of section 1501 (relating to character of service and facilities), and the commission may establish incentive programs to encourage such system upgrades. Disputes concerning facilities shall be subject to the jurisdiction of the commission and may be initiated by the filing of a complaint under section 701 (relating to complaints) by the electric generation supplier or the customer.

(c) Customer billing.--Subject to the right of an end-use customer to choose to receive separate bills from its electric generation supplier, the electric distribution company may be responsible for billing customers for all electric services, consistent with the regulations of the commission, regardless of the identity of the provider of those services.

(1) Customer bills shall contain unbundled charges sufficient to enable the customer to determine the basis for those charges.

(2) If services are provided by an entity other than the electric distribution company, the entity that provides those services shall furnish to the electric distribution company billing data sufficient to enable the electric distribution company to bill customers.

(3) The electric distribution company shall not be required to forward payment to entities providing services to customers, and on whose behalf the electric distribution company is billing those customers, before the electric distribution company has received payment for those services from customers.

(d) Consumer protections and customer service.--The electric distribution company shall continue to provide customer service functions consistent with the regulations of the commission, including meter reading, complaint resolution and collections. Customer services shall, at a minimum, be maintained at the same level of quality under retail competition.

(1) The commission shall establish regulations to ensure that an electric distribution company does not change a customer's electricity supplier without direct oral confirmation from the customer of record or written evidence of the customer's consent to a change of supplier.

(2) The commission shall establish regulations to require each electric distribution company, electricity supplier, marketer, aggregator and broker to provide adequate and accurate customer information to enable customers to make informed choices regarding the purchase of all electricity services offered by that provider. Information shall be provided to consumers in an understandable format that enables consumers to compare prices and services on a uniform basis.

(3) Prior to the implementation of any restructuring plan under section 2806 (relating to implementation, pilot programs and performance-based rates), each electric distribution company, in conjunction with the commission, shall implement a consumer education program informing customers of the changes in the electric utility industry. The program shall provide consumers with information necessary to help them make appropriate choices as to their electric service. The education program shall be subject to approval by the commission.

(e) Obligation to serve.--A default service provider's obligation to provide electric generation supply service following the expiration of a generation rate cap specified under section 2804(4) (relating to standards for restructuring of electric industry) or a restructuring plan under section 2806(f) is revised as follows:

(1) While an electric distribution company collects either a competitive transition charge or an intangible transition charge or until 100% of its customers have choice, whichever is longer, the electric distribution company shall continue to have the full obligation to serve, including the connection of customers, the delivery of electric energy and the production or acquisition of electric energy for customers.

(2) (Deleted by amendment).

(3) (Deleted by amendment).

(3.1) Following the expiration of an electric distribution company's obligation to provide electric generation supply service to retail customers at capped rates, if a customer contracts for electric generation supply service and the chosen electric generation supplier does not provide the service or if a customer does not choose an alternative electric generation supplier, the default service provider shall provide electric generation supply service to that customer pursuant to a commission-approved competitive procurement plan. The electric power acquired shall be procured through competitive procurement processes and shall include one or more of the following:

(i) Auctions.

(ii) Requests for proposal.

(iii) Bilateral agreements entered into at the sole discretion of the default service provider which shall be at prices which are:

(A) no greater than the cost of obtaining generation under comparable terms in the wholesale market, as determined by the commission at the time of execution of the contract; or

(B) consistent with a commission-approved competition procurement process. Any agreement between affiliated parties shall be subject to review and approval of the commission under Chapter 21 (relating to relations with affiliated interests). In no case shall the cost of obtaining generation from any affiliated interest be greater than the cost of obtaining generation under comparable terms in the wholesale market at the time of execution of the contract.

(3.2) The electric power procured pursuant to paragraph (3.1) shall include a prudent mix of the following:

(i) Spot market purchases.

(ii) Short-term contracts.

(iii) Long-term purchase contracts, entered into as a result of an auction, request for proposal or bilateral contract that is free of undue influence, duress or favoritism, of more than four and not more than 20 years. The default service provider shall have sole discretion to determine the source and fuel type. Long-term purchase contracts under this subparagraph may not constitute more than 25% of the default service provider's projected default service load unless the commission, after a hearing, determines for good cause that a greater portion of load is necessary to achieve least cost procurement. This subparagraph shall not apply to contracts executed under paragraph (5).

(3.3) The commission may determine that a contract is required to be extended for a longer term of up to 20 years, if the extension is necessary to ensure adequate and reliable service at least cost to customers over time.

(3.4) The prudent mix of contracts entered into pursuant to paragraphs (3.2) and (3.3) shall be designed to ensure:

(i) Adequate and reliable service.

(ii) The least cost to customers over time.

(iii) Compliance with the requirements of paragraph (3.1).

(3.5) Except as set forth in paragraph (5)(ii), the provisions of this section shall apply to any type of energy purchased by a default service provider to provide electric generation supply service, including energy or alternative energy portfolio standards credits required to be purchased under the act of November 30, 2004 (P.L.1672, No.213), known as the Alternative Energy Portfolio Standards Act. The commission shall apply paragraph (3.4) to comparable types of energy sources.

(3.6) The default service provider shall file a plan for competitive procurement with the commission and obtain commission approval of the plan considering the standards in paragraphs (3.1), (3.2), (3.3) and (3.4) before the competitive process is implemented. The commission shall hold hearings as necessary on the proposed plan. If the commission fails to issue a final order on the plan within nine months of the date that the plan is filed, the plan shall be deemed to be approved and the default service provider may implement the plan as filed. Costs incurred through an approved competitive procurement plan shall be deemed to be the least cost over time as required under paragraph (3.4)(ii).

(3.7) At the time the commission evaluates the plan and prior to approval, in determining if the default electric service provider's plan obtains generation supply at the least cost, the commission shall consider the default service provider's obligation to provide adequate and reliable service to customers and that the default service provider has obtained a prudent mix of contracts to obtain least cost on a long-term, short-term and spot market basis and shall make specific findings which shall include the following:

(i) The default service provider's plan includes prudent steps necessary to negotiate favorable generation supply contracts.

(ii) The default service provider's plan includes prudent steps necessary to obtain least cost generation supply contracts on a long-term, short-term and spot market basis.

(iii) Neither the default service provider nor its affiliated interest has withheld from the market any generation supply in a manner that violates Federal law.

(3.8) Notwithstanding sections 508 (relating to power of the commission to vary, reform and revise contracts) and 2102 (relating to approval of contracts with affiliated interests), the commission may modify contracts or disallow costs only when the party seeking recovery of the costs of a procurement plan is, after hearing, found to be at fault for the following:

(i) not complying with the commission-approved procurement plan; or

(ii) the commission of fraud, collusion or market manipulation with regard to these contracts.

(3.9) The default service provider shall have the right to recover on a full and current basis, pursuant to a reconcilable automatic adjustment clause under section 1307 (relating to sliding scale of rates; adjustments), all reasonable costs incurred under this section and a commission-approved competitive procurement plan.

(4) If a customer that chooses an alternative supplier and subsequently desires to return to the local distribution company for generation service, the local distribution company shall treat that customer exactly as it would any new applicant for energy service.

(5) (i) Notwithstanding paragraph (3.1), the electric distribution company or commission-approved alternative supplier may, in its sole discretion, offer large

customers with a peak demand of 15 megawatts or greater at one meter at a location in its service territory any negotiated rate for service at all of the customers' locations within the service territory for any duration agreed upon by the electric distribution company or commission-approved alternative supplier and the large customer. The commission shall permit, but shall not require, an electric distribution company or commission-approved alternative supplier to provide service to large customers under this paragraph. Contract rates entered into under this paragraph shall be subject to review by the commission in order to ensure that all costs related to the rates are borne by the parties to the contract and that no costs related to the rates are borne by other customers or customer classes. If no costs related to the rates are borne by other customers or customer classes, the commission shall approve the contract within 90 days of its filing, or it shall be deemed approved by operation of law upon expiration of the 90 days. Information submitted under this paragraph shall be subject to the commission's procedures for the filing of confidential and proprietary information.

(ii) For purposes of providing service under this paragraph to customers with a peak demand of 20 megawatts or greater at one meter at a location within that distribution company's service territory, an electric distribution company that has completed its restructuring transition period as of the effective date of this paragraph may, in its sole discretion, acquire an interest in a generation facility or construct a generation facility specifically to meet the energy requirements of the customers, including the electric requirements of the customers' other billing locations within its service territory. The electric distribution company must commence construction of the generation facility or contract to acquire the generation interest within three years after the effective date of this paragraph, except that the electric distribution company may add to the generation facilities it commenced construction or contracted to acquire after this three-year period to serve additional load of customers for whom it commenced construction or contracted to acquire generation within three years. Nothing in this paragraph requires or authorizes the commission to require an electric distribution company to commence construction or acquire an interest in a generation facility. The electric distribution company's interest in the generation facility it built or contracted to acquire shall be no larger than necessary to meet peak demand of customers served under this subparagraph. During times when the customer's demand is less than the electric distribution company's generation interest, the electric distribution company may sell excess power on the wholesale market. At no time shall the costs associated with the generating facility interests be included in rate base or otherwise reflected in rates. The generation facility interests shall not be commission-regulated assets.

(6) A default service plan approved by the commission prior to the effective date of this section shall remain in

effect through its approved term. At its sole discretion, the default service provider may propose amendments to its approved plan that are consistent with this section, and the commission shall issue a decision whether to approve or disapprove the proposed amendments within nine months of the date that the amendments are filed. If the commission fails to issue a final order within nine months, the amendments shall be deemed to be approved and the default service provider may implement the amendments as filed.

(7) The default service provider shall offer residential and small business customers a generation supply service rate that shall change no more frequently than on a quarterly basis. All default service rates shall be reviewed by the commission to ensure that the costs of providing service to each customer class are not subsidized by any other class.

(f) Smart meter technology and time of use rates.--

(1) Within nine months after the effective date of this paragraph, electric distribution companies shall file a smart meter technology procurement and installation plan with the commission for approval. The plan shall describe the smart meter technologies the electric distribution company proposes to install in accordance with paragraph (2).

(2) Electric distribution companies shall furnish smart meter technology as follows:

(i) Upon request from a customer that agrees to pay the cost of the smart meter at the time of the request.

(ii) In new building construction.

(iii) In accordance with a depreciation schedule not to exceed 15 years.

(3) Electric distribution companies shall, with customer consent, make available direct meter access and electronic access to customer meter data to third parties, including electric generation suppliers and providers of conservation and load management services.

(4) In no event shall lost or decreased revenues by an electric distribution company due to reduced electricity consumption or shifting energy demand be considered any of the following:

(i) A cost of smart meter technology recoverable under a reconcilable automatic adjustment clause under section 1307(b), except that decreased revenues and reduced energy consumption may be reflected in the revenue and sales data used to calculate rates in a distribution rate base rate proceeding filed under section 1308 (relating to voluntary changes in rates).

(ii) A recoverable cost.

(5) By January 1, 2010, or at the end of the applicable generation rate cap period, whichever is later, a default service provider shall submit to the commission one or more proposed time-of-use rates and real-time price plans. The commission shall approve or modify the time-of-use rates and real-time price plan within six months of submittal. The default service provider shall offer the time-of-use rates and real-time price plan to all customers that have been provided with smart meter technology under paragraph (2)(iii). Residential or commercial customers may elect to participate in time-of-use rates or real-time pricing. The default service provider shall submit an annual report to the price programs

and the efficacy of the programs in affecting energy demand and consumption and the effect on wholesale market prices.

(6) The provisions of this subsection shall not apply to an electric distribution company with 100,000 or fewer customers.

(7) An electric distribution company may recover reasonable and prudent costs of providing smart meter technology under paragraph (2)(ii) and (iii), as determined by the commission. This paragraph includes annual depreciation and capital costs over the life of the smart meter technology and the cost of any system upgrades that the electric distribution company may require to enable the use of the smart meter technology which are incurred after the effective date of this paragraph, less operating and capital cost savings realized by the electric distribution company from the installation and use of the smart meter technology. Smart meter technology shall be deemed to be a new service offered for the first time under section 2804(4)(vi). An electric distribution company may recover smart meter technology costs:

(i) through base rates, including a deferral for future base rate recovery of current basis with carrying charge as determined by the commission; or

(ii) on a full and current basis through a reconcilable automatic adjustment clause under section 1307.

(g) Definition.--As used in this section, the term "smart meter technology" means technology, including metering technology and network communications technology capable of bidirectional communication, that records electricity usage on at least an hourly basis, including related electric distribution system upgrades to enable the technology. The technology shall provide customers with direct access to and use of price and consumption information. The technology shall also:

(1) Directly provide customers with information on their hourly consumption.

(2) Enable time-of-use rates and real-time price programs.

(3) Effectively support the automatic control of the customer's electricity consumption by one or more of the following as selected by the customer:

(i) the customer;

(ii) the customer's utility; or

(iii) a third party engaged by the customer or the customer's utility.

(July 17, 2007, P.L.120, No.36, eff. imd.; Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 amended subsec. (e) and added subsecs. (f) and (g).

§ 2808. Competitive transition charge.

(a) General rule.--To provide each electric utility with an opportunity to recover its transition or stranded costs following the commission's determination under subsection (c), every customer accessing the transmission or distribution network shall pay a competitive transition charge to the electric distribution company in whose certificated territory that customer is located. The costs to be recovered shall be allocated to customer classes in a manner that does not shift interclass or intraclass costs and maintains consistency with the allocation methodology for utility production plant accepted by the commission in the electric utility's most recent base rate proceeding. If a customer installs on-site generation which operates in parallel with other generation on the public utility's system and which significantly reduces the customer's purchases of electricity through the transmission and distribution network, the customer's fully allocated share of transition or stranded costs shall be recovered from the customer through a competitive transition charge. The recovery of transition or stranded costs associated with existing generating facilities is contingent on continued operation at reasonable availability levels of the generation facilities for which recovery has been approved, except when the generation facility is uneconomic on a production cost basis because of the transition to a competitive market.

(b) Period for collecting competitive transition charge.--The competitive transition charge shall be included on bills to customers for a period not to exceed nine years from the effective date of this chapter unless an alternative payment methodology is mutually agreed upon by the customer and the utility or unless the commission in its discretion and for good cause shown orders an alternative payment period. In establishing the length of the period for collection of the competitive transition charge, the commission shall consider the effect on the ability of the Commonwealth to compete in attracting industry and jobs, on the financial health of electric utilities and other relevant factors.

(c) Determination of competitive transition charge.--In determining the level of transition or stranded costs that an electric utility may recover through the competitive transition charge, the commission shall apply the following principles:

(1) The commission shall allow recovery of regulatory assets and other deferred charges typically recoverable under current regulatory practice, the unfunded portion of the utility's projected nuclear generating plant decommissioning costs and cost obligations under contracts with nonutility generating projects that have received a commission order. Nothing in this chapter shall be construed as requiring an electric utility or a nonutility generating project to enter into an arrangement to buy down, buy out and terminate or otherwise restructure a contract or as authorizing the commission to require a utility to pursue such an arrangement with a nonutility generating project.

(2) The commission shall allow recovery of an electric utility's prudently incurred costs related to cancellation, buyout, buydown or renegotiation of nonutility generating projects consistent with section 527 (relating to cogeneration rules and regulations).

(3) The commission shall determine the level of other generation-related transition or stranded costs that may be recovered through the competitive transition charge.

(4) The commission shall consider the extent to which the electric utility has undertaken efforts to mitigate generation-related transition or stranded costs by appropriate means in a manner that is reasonable under all of the circumstances, including consideration of whether mitigation has been commensurate with the magnitude of the electric utility's generation-related transition or stranded costs. During the transition period, electric utilities shall have

the duty to mitigate generation-related transition or stranded costs to the extent practicable. Efforts may include the following:

(i) Acceleration of depreciation and amortization of existing rate base generation assets.

(ii) Minimization of new capital spending for existing rate base generation assets.

(iii) Reallocation of depreciation reserves to existing rate base generation assets.

(iv) Reduction of book assets by application of new proceeds of any sale of idle or underutilized existing rate base generation assets.

(v) Maximization of market revenues from existing rate base generation assets.

(vi) Issuance of securitized debt pursuant to the provisions of section 2812 (relating to approval of transition bonds).

(5) Of equal importance to the mitigation efforts under paragraph (4), the commission shall consider efforts undertaken over time, prior to the enactment of this chapter, to reduce or moderate customer rate levels while maintaining safe and efficient operations.

(d) Commission review.--As a component of its restructuring plan, each electric utility shall file with the commission a recovery plan, including a proposed competitive transition charge and supporting documentation. In evaluating a recovery plan and any proposed competitive transition charge, the commission shall schedule open evidentiary hearings with proper notice and opportunity for all parties to cross-examine witnesses as necessary.

(e) Use of transition bonds.--After the effective date of this chapter, a utility may apply to the commission for a qualified rate order under section 2812 for some or all of its transition or stranded costs.

(1) In evaluating a utility application under this subsection, the commission shall schedule hearings, as necessary.

(2) If the commission issues a qualified rate order under section 2812 and if the transition bonds approved by that order are successfully issued, then:

(i) the utility shall impose and collect through its customer bills the intangible transition charges approved by that qualified rate order; and

(ii) simultaneously, either the utility's rates for electric service or the utility's competitive transition charges shall be reduced by an amount equal to the revenue requirement of the transition or stranded costs for which transition bonds have been successfully issued.

(f) Annual revenue.--Consistent with section 1307(e) (relating to sliding scale of rates; adjustments), the commission shall establish procedures for the annual review of the competitive transition charge. The review shall reconcile the annual revenues received from the charge with the annual amortization of transition or stranded costs approved by the commission under this section. The commission shall adjust the competitive transition charge based upon underrecovery or overrecovery of the annual amortization amount.

Cross References. Section 2808 is referred to in sections 2802, 2803, 2804, 2812 of this title.

§ 2809. Requirements for electric generation suppliers.

(a) License requirement.--No person or corporation, including municipal corporations which choose to provide service outside their municipal limits except to the extent provided prior to the effective date of this chapter, brokers and marketers, aggregators and other entities, shall engage in the business of an electric generation supplier in this Commonwealth unless the person or corporation holds a license issued by the commission. Consistent with 15 Pa.C.S. Ch. 74 (relating to generation choice for customers of electric cooperatives), electric cooperative corporations must possess a certificate for service to supply generation services beyond their territorial limits.

(b) License application and issuance.--An application for an electric generation supplier license must be made to the commission in writing, be verified by oath or affirmation and be in such form and contain such information as the commission may by its regulations require. A license shall be issued to any qualified applicant, authorizing the whole or any part of the service covered by the application, if it is found that the applicant is fit, willing and able to perform properly the service proposed and to conform to the provisions of this title and the lawful orders and regulations of the commission under this title, including the commission's regulations regarding standards and billing practices, and that the proposed service, to the extent authorized by the license, will be consistent with the public interest and the policy declared in this chapter; otherwise, such application shall be denied.

(c) Financial responsibility.--

(1) In order to ensure the safety and reliability of the generation of electricity in this Commonwealth, no energy supplier license shall be issued or remain in force unless the holder complies with all of the following:

(i) Furnishes a bond or other security approved by the commission in form and amount to ensure the financial responsibility of the electric generation supplier and the supply of electricity at retail in accordance with contracts, agreements or arrangements.

(ii) Certifies to the commission that it will pay and in subsequent years has paid the full amount of taxes imposed by Articles II and XI of the act of March 4, 1971 (P.L.6, No.2), known as the Tax Reform Code of 1971, and any tax imposed by this chapter.

(iii) Provides the commission with the address of the participant's principal office in this Commonwealth or the address of the participant's registered agent in this Commonwealth, the latter being the address at which the participant may be served process.

(iv) Agrees that it shall be subject to all taxes imposed by the Tax Reform Code of 1971 and any tax imposed by this chapter.

Failure of an electricity supplier to pay a tax referred to in this paragraph or to otherwise comply with the provisions of this paragraph shall be cause for the commission to revoke the license of the electricity supplier.

(2) If an electricity supplier other than an electric distribution company does not pay the tax imposed upon gross

receipts under section 1101 of the Tax Reform Code of 1971 or this chapter, the electric distribution company to whose retail customer the electricity supplier provided generation service shall remit the unpaid tax, as a tax on the use of electricity in this Commonwealth, to the Department of Revenue and may collect or seek reimbursement of the tax so paid from the electricity provider or any other appropriate party that used the electricity in this Commonwealth. The department shall collect and enforce the use tax herein provided under section 1102 of the Tax Reform Code of 1971. Failure of the electric distribution company to pay the amount within 30 days after notice provided by the department shall cause interest to be imposed on the electric distribution company in accordance with Article XI of the Tax Reform Code of 1971. Interest shall be calculated from the 31st day after the department gives the notice required in this paragraph. An electric distribution company or other appropriate person may challenge the imposition of the tax and interest by filing a petition with the department not later than 30 days after the date on which the tax became due.

(d) Transferability of licenses.--No license issued under this chapter may be transferred without prior commission approval.

(e) Form of regulation of electric generation suppliers.--The commission may forbear from applying requirements of this part which it determines are unnecessary due to competition among electric generation suppliers. In regulating the service of electric generation suppliers, the commission shall impose requirements necessary to ensure that the present quality of service provided by electric utilities does not deteriorate, including assuring that adequate reserve margins of electric supply are maintained and assuring that 52 Pa. Code Ch. 56 (relating to standards and billing practices for residential utility service) are maintained.

(f) Availability of the services of brokers and marketers or aggregators.--Prior to approving the licensure of any broker and marketer or aggregator, the commission shall set forth standards to ensure that all retail customer classes may choose to purchase electricity through a broker and marketer or aggregator. The commission shall also ensure that brokers, marketers and aggregators comply with 52 Pa. Code Ch. 56.

(g) Annual fees.--The commission may establish, by order or rule, on a reasonable cost basis, fees to be charged for annual activities related to the oversight of electric generation suppliers.

(Oct. 22, 2014, P.L.2545, No.155, eff. 60 days)

2014 Amendment. Act 155 added subsec. (g). See section 1 of Act 155 in the appendix to this title for special provisions relating to legislative findings and declarations.

References in Text. Chapter 74 of Title 15, referred to in subsec. (a), is expired.

Cross References. Section 2809 is referred to in sections 102, 2804, 2810 of this title.

§ 2810. Revenue-neutral reconciliation.

(a) General intent of revenue-neutral reconciliation.--It is the intention of the General Assembly that the restructuring of the electric industry be accomplished in a manner that allows Pennsylvania to enjoy the benefits of competition, promotes the competitiveness of Pennsylvania's electric utilities and maintains revenue neutrality to the Commonwealth. This section is not intended to cause a shift in proportional tax obligations among customer classes or individual electric distribution companies. It is the intention of the General Assembly to establish this revenue replacement at a level necessary to recoup losses that may result from the restructuring of the electric industry and the transition thereto.

(b) Imposition.--

(1) For tax periods beginning on or after January 1, 1999, a tax at the rate provided in subsection (c) is imposed upon the gross receipts of electric distribution companies and electric generation suppliers.

(2) A tax at the rate provided in subsection (c) is imposed upon the gross receipts of any municipality owned or operated public utility or of any public utility service furnished by any municipality. Gross receipts shall be exempt from the tax to the extent that gross receipts are derived from sales of electric energy inside the limits of the municipality owning or operating the public utility or furnishing the public utility service.

(3) A tax at the rate provided in subsection (c) is imposed upon the gross receipts derived from any electric cooperative owned or operated public utility or from any public utility service furnished by any electric cooperative. Gross receipts shall be exempt from the tax to the extent that gross receipts are derived from sales for resale or sales of electric energy within the limits of its service territory as set forth in 15 Pa.C.S. § 7406 (relating to competition by electric cooperatives).

(c) Rate.--

(1) By December 1, 1998, and each October 1 thereafter until and including October 1, 2002, the Secretary of Revenue shall publish the rate of tax as provided in paragraph (2) in the form of a notice in the Pennsylvania Bulletin and the rate shall apply to the tax imposed by subsection (b) for the period beginning the next January 1. The tax rate published on October 1, 2002, shall continue in force without further adjustment. If the commission determines under section 2806(c) (relating to implementation, pilot programs and performance-based rates) to extend the transition period by more than six months, the requirement for an annual adjustment of the tax rate shall be extended by one additional year. The secretary shall also certify the rate calculated to the majority and minority chairs of the Appropriations Committee of the Senate and the Appropriations Committee of the House of Representatives and detail the calculations of the rate.

(2) The secretary shall calculate the rate for the periods beginning on and after January 1, 1999, in the manner set forth in this paragraph:

(i) Multiply the 1995-1996 fiscal tax revenue base by a fraction, the numerator of which is the total kilowatt hours of electricity distributed for ultimate consumption in Pennsylvania in the preceding calendar year as certified by the commission and the denominator of which is the total kilowatt hours of electricity distributed for ultimate consumption in Pennsylvania in the calendar year 1995 as certified by the commission.

(ii) From the product derived under subparagraph (i), subtract the total cash payments made to the department during the Commonwealth's preceding fiscal year on account of affected taxes actually paid by each electric distribution company and electric generation supplier and by any other entity, including a successor, whose affected taxes are contained in the 1995-1996 fiscal tax revenue base.

(iii) Divide the difference derived under subparagraph (ii) by the total gross receipts in the preceding calendar year as certified by the commission to determine the tax rate. The tax rate under this subparagraph shall be a decimal rounded to three places.

(3) On August 1, 2000, August 1, 2001, and August 1, 2002, the department shall deliver a report to the General Assembly and the Governor that shall describe the dynamic economic effect upon the affected taxes due to electric utility restructuring. It is the purpose of this report to provide the General Assembly and the Governor with information to determine whether it is appropriate to consider modifying the calculation described in paragraph (2) to reflect additional tax revenues, if any, resulting from the dynamic economic effects upon the affected taxes.

(4) If the effective rate for any affected tax is different from the effective rate for such affected tax in the 1995-1996 fiscal tax revenue base, an adjustment shall be made to the computation of the rate of tax under paragraph (2) by multiplying that portion of the 1995-1996 fiscal tax revenue base attributable to the affected tax by a fraction, the numerator of which is the effective rate of the affected tax for the preceding fiscal year and the denominator of which is the effective rate of tax of the affected tax in the base fiscal year.

(5) For negative rates:

(i) If the rate of tax calculated for a tax year prior to the tax year beginning January 1, 2004, or January 1, 2005, in the event of an extension by more than six months by the commission as provided in section 2806(c) is negative, a credit equal to the negative tax rate for such tax year multiplied by the taxable gross receipts for that tax year shall be allowed against the taxpayer's liability for any tax for that tax year imposed under Article XI of the act of March 4, 1971 (P.L.6, No.2), known as the Tax Reform Code of 1971.

(ii) If the rate of tax calculated as the final adjustment is negative for the tax period beginning January 1, 2003, or January 1, 2004, in the event of an extension by more than six months by the commission as provided in section 2806(c), the rate of tax imposed by section 1101(b) of the Tax Reform Code of 1971 for the tax years beginning January 1, 2004, and thereafter, or January 1, 2005, and thereafter, in the event of an extension by more than six months, shall be adjusted and set as follows: the tax rate expressed as a decimal rounded to three positions shall be subtracted from .044 or the current rate imposed under section 1101(b) of the Tax Reform Code of 1971 to determine the adjusted tax rate. The adjusted tax rate shall be published in the Pennsylvania Bulletin.

(6) Information to be provided to the department or the commission shall be as follows:

(i) To ensure the identification of cash payments for purposes of subsection (d), the commission shall require any licensee, electric distribution company, electric generation supplier or other person affected to disclose on its license application, renewal or transfer its State tax account or similar number relative to any of the taxes specified.

(ii) The commission shall report and certify to the secretary of the department by August 1, 1998, and each August 1 thereafter the total amount of electricity distributed for ultimate consumption in this Commonwealth during the previous two calendar years and the total gross receipts for the past year.

(iii) As a condition of licensure, the commission shall require each electric distribution company and electric generation supplier to report their annual gross receipts in this Commonwealth.

(iv) For purposes of enforcing sections 2806 and 2809 (relating to requirements for electric generation suppliers) as they relate to the payment of State taxes, an applicant for the grant, renewal or transfer of a license issued under this title shall, by filing an application with the commission, waive confidentiality with respect to State tax information regarding the applicant in the possession of the department, regardless of the source of the information, and shall consent to the department providing that information to the commission.

(7) (Repealed).

(d) Payment of tax and reports.--The tax imposed under subsection (b) shall be paid within the time prescribed by law. For the purpose of ascertaining the amount of the tax, the treasurer or other appropriate officer of the taxpayer shall transmit to the department by March 15 an annual report, and under oath or affirmation, of the amount of gross receipts received by the taxpayer during the prior calendar year. The treasurer or other appropriate officer of the taxpayer liable to report or pay taxes imposed under subsection (b), except municipalities and cooperatives, shall transmit to the department by March 15 a tentative report for the prior calendar year. The tentative report shall set forth all of the following:

(i) The amount of gross receipts received in the period of 12 months next preceding and reported in the annual report.

(ii) The gross receipts received in the first three months of the current calendar year.

(iii) Other information as the department may require.

(e) Tax computation.--Upon the date its tentative report is required to be made, the taxpayer making a tentative report shall transmit the report to the department on account of the tax due for the current calendar year and compute and make payment of the tentative tax with the report under section 3003 of the Tax Reform Code of 1971.

(f) Time to file reports.--The time for filing annual reports may be extended, estimated settlements may be made by the department if reports are not filed, and the penalties for failing to file reports and pay the taxes imposed under subsection (b) shall be as prescribed by the laws defining the powers and duties of the department. If the works of a taxpayer are operated by another taxpayer, the taxes imposed under subsection (b) shall be apportioned between the taxpayers in accordance with the terms of their respective leases or agreements. For the payment of the apportioned taxes, the Commonwealth shall first look to the taxpayer operating the works. Upon payment by that taxpayer, no other taxpayer shall be held liable for any tax imposed under subsection (b).

(g) Timely mailing treated as timely filing and payment.-- Notwithstanding the provisions of any State tax law to the contrary, whenever payment of all or any portion of a State tax is required by law to be received by the department or other agency of the Commonwealth by a day certain, the taxpayer shall be deemed to have complied with that law if the letter transmitting payment of the tax which has been received by the department is postmarked by the United States Postal Service on or prior to the final day on which the payment is to be received.

(h) Procedure, enforcement and penalties.--Parts III, IV, VI and VII of Article IV and Article XXX of the Tax Reform Code of 1971 shall apply to this section insofar as they are consistent with this section and applicable to the tax imposed under subsection (b). Notwithstanding the provisions of section 403(d) of the Tax Reform Code of 1971, if the officers of any corporation subject to tax under this chapter neglect or refuse to make a report as required in this chapter or knowingly make a false report, the department shall add to the tax determined to be due a penalty of 5% of the amount of tax due for each month or fraction of a month until the penalty has reached 25% and thereafter a penalty of 1% of the amount of tax due for each month or fraction of a month. Penalties added to the tax shall not bear interest.

(i) Electric light, waterpower and hydroelectric utilities.-- The terms "electric light company," "waterpower company" and "hydro-electric company," as used in section 1101(b) of the Tax Reform Code of 1971, shall be deemed to include electric distribution companies and electric generation suppliers.

(j) Sales of electric energy.--Retail sales of electric generation, transmission, distribution or supply of electric energy, dispatching services, customer services, competitive transition charges, intangible transition charges and universal service and energy conservation charges and such other retail sales in this Commonwealth the receipts of which, if bundled, would have been deemed to be sales of electric energy prior to the effective date of this chapter shall be deemed sales of electric energy for purposes of section 1101 of the Tax Reform Code of 1971. The phrases "doing business in this Commonwealth" and "engaged in electric light and power business, waterpower business and hydro-electric business in this Commonwealth," as such terms are used in section 1101(b) of the Tax Reform Code of 1971 and in this chapter, shall be construed to include the direct or indirect engaging in, transacting or conducting of activity in this Commonwealth for the purpose of establishing or maintaining a market for the sales of electric energy and include obtaining a license or certification from the commission to supply electric energy. Retail sales of generation shall be deemed to occur at the meter of the retail consumer.

(k) Electric cooperatives.--Section 1101(b) of the Tax Reform Code of 1971 shall apply to electric cooperatives and impose a tax upon the gross receipts derived from any electric cooperative owned or operated public utility or from any public utility service furnished by any electric cooperative. Gross receipts shall be exempt from the tax to the extent that the gross receipts are derived from sales for resale or sales of electric energy within the limits of its service territory as set forth in 15 Pa.C.S. § 7406.

(l) Provisions to be construed with utilities gross receipts tax.--Subsections (i), (j) and (k) shall be construed in conjunction with Article XI of the Tax Reform Code of 1971 and shall be effective for tax years beginning January 1, 1997, and thereafter.

(m) Indemnification.--The electric distribution utility company's tariff shall provide that, if an electric distribution company becomes liable under sections 2806(g) and 2809(c) for State taxes not paid by an electric generation supplier, that electric generation supplier shall indemnify the electric distribution company for the amount of the liability so imposed upon the electric distribution utility.

(n) Definitions.--As used in this section, the following words and phrases shall have the meanings given to them in this subsection:

"Affected taxes." The taxes imposed under Articles II, IV, VI and XI and section 2301(f) of the act of March 4, 1971 (P.L.6, No.2), known as the Tax Reform Code of 1971.

"Base fiscal year." The year beginning on July 1, 1995, and ending on June 30, 1996.

"Department." The Department of Revenue of the Commonwealth.

"Effective rate." The tax rate applicable during the fiscal year or, if more than one rate is applicable, the average of the rates that were in effect for each month of the fiscal year.

"Fiscal year." A year beginning on July 1 and ending on the subsequent June 30.

"Gross receipts." The gross receipts from the retail sales of electric energy as defined in section 1101(b) of the Tax Reform Code of 1971.

"1995-1996 fiscal tax revenue base." The receipts from affected taxes from the fiscal year 1995-1996, such amount being $984,141,837.

"Portion of the 1995-1996 fiscal tax revenue base attributable to the affected tax." The following amounts for the tax indicated:

Tax	Amount
Corporate net income tax	$181,628,433
Capital stock-franchise tax	$117,495,605
Sales and use tax	$187,401,632
Public utility realty tax	$ 43,883,573
Utilities gross receipts tax	$453,732,594

"Total utilities gross receipts." The total gross receipts for a calendar year for all electric distribution companies and electric generation suppliers which are derived from the sales of electric energy and required to be reported to the commission under subsection (c)(6)(iii).

(Dec. 23, 2003, P.L.250, No.46, eff. imd.)

2003 Repeal. Act 46 repealed subsec. (c)(7).

References in Text. Section 7406 of Title 15, referred to in subsec. (b)(3), expired.

Cross References. Section 2810 is referred to in sections 102, 2804 of this title.

§ 2811. Market power remediation.

(a) Monitoring competitive conditions.--The commission shall monitor the market for the supply and distribution of electricity to retail customers and take steps as set forth in this section to prevent anticompetitive or discriminatory conduct and the unlawful exercise of market power.

(b) Initiation of investigations.--Upon complaint or upon its own motion for good cause shown, the commission shall conduct an investigation of the impact on the proper functioning of a fully competitive retail electricity market, including the effect of mergers, consolidations, acquisition or disposition of assets or securities of electricity suppliers, transmission congestion and anticompetitive or discriminatory conduct affecting the retail distribution of electricity.

(c) Conduct of investigations.--

(1) The commission may require an electricity supplier to provide information, including documents and testimony, in accordance with the commission's regulations regarding the discovery of information from any electricity supplier.

(2) Confidential, proprietary or trade secret information provided under this subsection shall not be disclosed to any person not directly employed or retained by the commission to conduct the investigation without the consent of the party providing the information.

(3) Notwithstanding the prohibition on disclosure of information in paragraph (2), the commission shall disclose information obtained under this subsection to the Office of Consumer Advocate and the Office of Small Business Advocate under an appropriate confidentiality agreement. The commission may disclose the information to appropriate Federal or State law enforcement officials if it determines that the disclosure of the information is necessary to prevent or restrain a violation of Federal or State law and it provides the party that provided the information with reasonable notice and opportunity to prevent or limit disclosure.

(d) Referrals and intervention.--If, as a result of an investigation conducted under this section, the commission has reason to believe that anticompetitive or discriminatory conduct, including the unlawful exercise of market power, is preventing the retail electricity customers in this Commonwealth from obtaining the benefits of a properly functioning and workable competitive retail electricity market, the commission, pursuant to its regulations, shall:

(1) Refer its findings to the Attorney General, the United States Department of Justice, the Securities and Exchange Commission or the Federal Energy Regulatory Commission.

(2) Subject to subsection (c)(3), disclose any information it has obtained in the course of its investigation to the agency or agencies to which it has made a referral under paragraph (1).

(3) Intervene, as provided and permitted by law or regulation, in any proceedings initiated as a result of a referral made under paragraph (1).

(e) Approval of proposed mergers, consolidations, acquisitions or dispositions.--

(1) In the exercise of authority the commission otherwise may have to approve the mergers or consolidations by electric utilities or electricity suppliers, or the acquisition or disposition of assets or securities of other public utilities or electricity suppliers, the commission shall consider whether the proposed merger, consolidation, acquisition or disposition is likely to result in anticompetitive or discriminatory conduct, including the unlawful exercise of market power, which will prevent retail electricity customers in this Commonwealth from obtaining the benefits of a properly functioning and workable competitive retail electricity market.

(2) Upon request for approval, the commission shall provide notice and an opportunity for open, public evidentiary hearings. If the commission finds, after hearing, that a proposed merger, consolidation, acquisition or disposition is likely to result in anticompetitive or discriminatory conduct, including the unlawful exercise of market power, which will prevent retail electricity customers in this Commonwealth from obtaining the benefits of a properly functioning and workable competitive retail electricity market, the commission shall not approve such proposed merger, consolidation, acquisition or disposition, except upon such terms and conditions as it finds necessary to preserve the benefits of a properly functioning and workable competitive retail electricity market.

(e.1) Market misconduct.--

(1) If an electric distribution company or any of its affiliated companies or any company that an electric distribution company has purchased generation from is found guilty of market manipulation, exercising market power or collusion by the Federal Energy Regulatory Commission or any Federal or State court or, if an electric distribution company or any one of its affiliated companies or any company that an electric distribution company has purchased generation from settles a claim of market manipulation, exercising market power or collusion that is brought by a regional transmission operator's market monitoring unit, the Federal Energy Regulatory Commission or another entity, the commission:

(i) Shall direct the electric distribution company to take any and all reasonable action to quantify the effect of the market misconduct upon Pennsylvania ratepayers.

(ii) Following public hearing on the matter and a finding of public interest, may direct the electric distribution company to take any and all reasonable legal action, including the filing of a lawsuit as may be necessary, to recover the quantified damages which shall be used to recompense Pennsylvania ratepayers affected by the market misconduct.

(2) If the electric distribution company fails to pursue reasonable action to quantify or seek recovery of damages for Pennsylvania ratepayers affected by market manipulation, the exercise of market power or collusion, the commission is

authorized, following notice and an opportunity of the electric distribution company to comply or contest, to assess a civil penalty, which shall not be recovered in rates, of not more than $10,000 per day for failure or neglect to obey an order of the commission, the continuance of the failure or neglect being a separate offense.

(3) Any monetary damages recovered by the electric distribution company shall be paid to affected Pennsylvania ratepayers in the form of a credit to their electric bills or as refunds.

(4) The provisions of this subsection shall be held to be in addition to and not in substitution for or limitation of any other provision of this title.

(f) Preservation of rights.--Nothing in this section shall restrict the right of any party to pursue any other remedy available to it under this part.
(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added subsec. (e.1).

§ 2812. Approval of transition bonds.

(a) Qualified rate orders.--Notwithstanding any other provision of law, the commission is authorized to issue qualified rate orders in accordance with the provisions of this subsection to facilitate the recovery or financing of qualified transition expenses of an electric utility or assignee.

(1) A qualified rate order may be adopted by the commission only upon the application of an electric utility and shall become effective in accordance with its terms. After the issuance of a qualified rate order, the electric utility retains sole discretion regarding whether to assign, sell or otherwise transfer intangible transition property or to cause the transition bonds to be issued, including the right to defer or postpone such assignment, sale, transfer or issuance.

(2) After the effective date of this chapter, an electric utility may file an application for a qualified rate order pursuant to the following procedures:

(i) Each application for a qualified rate order shall contain a complete accounting of the utility's transition or stranded costs, detailed information regarding the utility's proposal for the sale of intangible transition property or the issuance of transition bonds and information regarding the electric utility's planned use of the proceeds of the sale or issuance. After the utility has filed its restructuring plan under section 2806 (relating to implementation, pilot programs and performance-based rates), the utility may incorporate by reference the information in the restructuring plan in providing the information.

(ii) An electric utility may file an application for a qualified rate order concurrently with, prior to, during or following the filing of its restructuring plan under section 2806. If an electric utility requests expedited review under subsection (b)(1)(i) or (ii), it shall designate in its application the portion of its total claimed transition or stranded costs for which it requests such expedited review.

(iii) After notice and an opportunity to be heard, the commission may issue a final qualified rate order for all or a portion of the amount of transition or stranded costs that it finds would be just and reasonable for the utility to recover from ratepayers under sections 2804 (relating to standards for restructuring of electric industry) and 2808 (relating to competitive transition charge). The commission shall issue a final qualified rate order only for the amounts for which it finds such issuance to be in the public interest. The commission shall complete its review of the application and issue its final determination by the later of nine months from the filing, unless the electric utility requests expedited treatment under subsection (b), or 15 days following the filing of the electric utility's restructuring plan under section 2806.

(b) Expedited review procedures.--

(1) The commission shall provide for expedited review of applications for qualified rate orders upon request of the electric utility pursuant to the following procedures:

(i) If the utility elects to file an application prior to the filing of its restructuring plan and requests expedited review, the commission, after notice and an opportunity to be heard, may issue a final qualified rate order approving the issuance of transition bonds for a portion of the utility's transition or stranded costs that the commission finds would be just and reasonable to recover from ratepayers under sections 2804 and 2808. The commission shall consider only the portion of the transition or stranded costs for which the utility requests approval to issue transition bonds. Consideration of all remaining amounts and amounts not resolved by the commission shall be deferred for consideration in the electric utility's restructuring plan proceeding under section 2806. The commission shall complete its review of the application and issue its final determination within 120 days after the request for expedited review but in no event earlier than 15 days after the utility has filed its restructuring plan under section 2806.

(ii) If the electric utility files an application for a qualified rate order concurrently with its restructuring plan or during the course of the restructuring plan proceeding, the electric utility may request, and the commission may allow, an accelerated determination of the application. After notice and an opportunity to be heard, the commission may issue a final qualified rate order approving the issuance of transition bonds for a portion of the utility's stranded or transition costs that the commission finds would be just and reasonable to recover from ratepayers under sections 2804 and 2808. The commission shall consider only the portion of the utility's transition or stranded costs for which the utility seeks expedited review. Consideration of all remaining amounts and amounts not resolved by the commission shall be deferred for consideration in a final order regarding the utility's restructuring plan under section 2806. The commission shall complete its review of the application and issue its final determination within 120 days after the request for expedited review.

(iii) If the electric utility files an application for a qualified rate order after the commission enters a final order regarding the utility's restructuring plan, and requests expedited treatment, the commission shall complete its review and issue its final determination within 120 days of the request for expedited review.

(2) The qualified rate order shall require that the proceeds from the assignment, sale or transfer or other financing of intangible transition property shall be used principally to reduce the electric utility's transition or stranded costs and to reduce the related capitalization, pursuant to a plan submitted by the electric utility in its application for a qualified rate order and approved by the commission.

(3) Notwithstanding any other provision of law, the commission has the power to specify that all or a portion of a qualified rate order shall be irrevocable. To the extent so specified, neither the order nor the intangible transition charges authorized to be imposed and collected under the order shall be subject to reduction, postponement, impairment or termination by any subsequent action of the commission. Nothing in this paragraph is intended to supersede the right of any party to judicial review of the qualified rate order.

(4) The commission shall provide in any qualified rate order for a procedure for the expeditious approval by the commission of periodic adjustments to the intangible transition charges that are the subject of the pertinent qualified rate order. Such adjustments shall ensure the recovery of revenues sufficient to provide for the payment of principal, interest, acquisition or redemption premium and for other fees, costs and charges in respect of transition bonds approved by the commission as part of or in conjunction with a qualified rate order. The commission shall determine whether the adjustments are required on each anniversary of the issuance of the qualified rate order and at the additional intervals as may be provided for in the qualified rate order. The adjustments, if required, shall be approved within 90 days of each anniversary of the issuance of the qualified rate order or of each additional interval provided for in the qualified rate order.

(5) Notwithstanding any other provision of law, on such conditions as the commission may approve, all or portions of the interest of an electric utility in intangible transition property may be assigned, sold or transferred to an assignee and may be pledged or assigned as security by an electric utility or assignee to or for the benefit of a financing party. To the extent that an interest is assigned, sold or transferred or is pledged or assigned as security, the commission shall authorize the electric utility to contract with the assignee or financing party that the electric utility will continue to operate its system to provide service to its customers, will impose and collect the applicable intangible transition charges for the benefit and account of the assignee or financing party and will account for and remit the applicable intangible transition charge to or for the account of the assignee or financing party. If the qualified rate order so provides, the obligations of the electric utility:

(i) shall be binding upon the electric utility, its successors and assigns; and

(ii) shall be required by the commission to be undertaken and performed by the electric utility and any other entity which provides electric service to a person that was a customer of an electric utility located within the certificated territory of the electric utility on the effective date of this chapter or that became a customer of electric services within such territory after the effective date of this chapter and is still located within such territory, as a condition to the provision of service to such customer by such electric utility or other entity, unless the customer has paid a termination charge in the manner and on the basis specified in the qualified rate order.

(6) The irrevocable status of any portion of a qualified rate order under paragraph (3) shall lapse and terminate to the extent that an assignment, sale or transfer of the intangible transition property resulting from the rate order or the issuance of the related transition bonds is not effected within the period specified in the qualified rate order.

(7) The effect of any subsequent refinancing of transition bonds upon the rates authorized in a qualified rate order shall be as provided in such order.

(8) In its qualified rate order, the commission shall afford flexibility in establishing the terms and conditions of the transition bonds, including repayment schedules, interest rates and other financing costs. The electric utility shall file the final terms of issuance with the commission.

(c) Intangible transition property.--

(1) Any right that an electric utility has in the intangible transition property prior to its sale or transfer or any other right created under this section or created in the qualified rate order and assignable under this section or assignable pursuant to a qualified rate order shall be only a contract right.

(2) The Commonwealth pledges to and agrees with the holders of any transition bonds issued under this section and with any assignee or financing party who may enter into contracts with an electric utility under this section that the Commonwealth will not limit or alter or in any way impair or reduce the value of intangible transition property or intangible transition charges approved by a qualified rate order until the transition bonds and interest on the transition bonds are fully paid and discharged or the contracts are fully performed on the part of the electric utility. Subject to other requirements of law, nothing in this paragraph shall preclude limitation or alteration if adequate compensation is made by law for the full protection of the intangible transition charges collected pursuant to a qualified rate order and of the holder of this transition bond and any assignee or financing party entering into contract with the electric utility.

(d) Security interests in intangible transition property.--

(1) Neither intangible transition property nor any right, title or interest of a utility or assignee described in paragraph (1) of the definition of "intangible transition

property" in subsection (g), whether before or after the issuance of the qualified rate order, shall constitute "an account" or "general intangibles" under 13 Pa.C.S. § 9102 (relating to definitions and index of definitions) nor shall any such right, title or interest pertaining to a qualified rate order, including the associated intangible transition property and any revenues, collections, claims, payments, money or proceeds of or arising from intangible transition charges pursuant to such order, be deemed proceeds of any right or interest other than in the order and the intangible transition property arising from the order.

(2) The granting, perfection and enforcement of security interests in intangible transition property to secure transition bonds is governed by this section rather than by Title 13 (relating to commercial code).

(3) A valid and enforceable security interest in intangible transition property shall attach and be perfected only by means of a separate filing with the commission, under regulations the commission prescribes. For this purpose:

(i) If the transition bonds are issued to finance any qualified transition expenses, as specified in the applicable qualified rate order, the lien of the bonds shall attach automatically to the intangible transition property relating to the expenses from the time of issuance of the bonds.

(ii) The lien under subparagraph (i) shall be deemed a valid and enforceable security interest in the intangible transition property securing the qualified transition bonds and shall be continuously perfected if, before the date of issuance specified in subparagraph (i) or within no more than ten days after the date, a filing has been made by or on behalf of the financing party to protect that security interest in accordance with the procedures prescribed by the commission under this subsection. Any filing in respect to such transition bonds shall take precedence over any other filing.

(iii) The lien under subparagraph (i) is enforceable against the assignee and all third parties, including judicial lien creditors, subject only to the rights of any third parties holding security interests in the intangible transition property previously perfected in the manner described in this subsection if value has been given by the purchasers of transition bonds. A perfected lien in intangible transition property is a continuously perfected security interest in all revenues and proceeds arising with respect to the associated intangible transition property, whether or not revenues have accrued. Intangible transition property constitutes property for the purposes of contracts securing transition bonds, whether or not the related revenues have accrued. The lien created under this paragraph is perfected and ranks prior to any other lien, including any judicial lien, which subsequently attaches to the intangible transition property, to the intangible transition charges and to the qualified rate order and any rights created by the order or any proceeds of the order. The relative priority of a lien created under this paragraph is not defeated or adversely affected by changes to the qualified rate order or to the intangible transition charges payable by any customer.

(iv) The relative priority of a lien created under this paragraph is not defeated or adversely affected by the commingling of revenues arising with respect to intangible transition property with funds of the electric utility or other funds of the assignee.

(v) If an event of default occurs under approved transition bonds, the holders of transition bonds or their authorized representatives, as secured parties, may foreclose or otherwise enforce the lien in the intangible transition property securing the transition bonds, subject to the rights of any third parties holding prior security interests in the intangible transition property perfected in the manner provided in this subsection. Upon application by the holders or their representatives, without limiting their other remedies, the commission shall order the sequestration and payment to the holders or their representatives of revenues arising with respect to the intangible transition property pledged to the holders. An order under this subparagraph shall remain in full force and effect notwithstanding any bankruptcy, reorganization or other insolvency proceedings with respect to the electric utility or assignee.

(4) The commission shall establish and maintain a separate system of records to reflect the date and time of receipt of all filings made under this subsection and may provide that transfers of intangible transition property to an assignee be filed in accordance with the same system.

(e) True sale.--A transfer of intangible transition property by an electric utility to an assignee which the parties have in the governing documentation expressly stated to be a sale or other absolute transfer, in a transaction approved in a qualified rate order, shall be treated as an absolute transfer of all of the transferor's right, title and interest, as in a true sale, and not as a pledge or other financing, of the intangible transition property, other than for Federal and State income and franchise tax purposes. Granting to holders of transition bonds a preferred right to the intangible transition property or the provision by the electric utility of any credit enhancement with respect to transition bonds shall not impair or negate the characterization of any transfer as a true sale, other than for Federal and State income and franchise tax purposes. A transfer of intangible transition property shall be deemed perfected as against third persons, including any judicial lien creditors, when all of the following have taken place:

(1) The commission has issued the qualified rate order creating intangible transition property.

(2) A sale or transfer of the intangible transition property in writing has been executed and delivered to the assignee.

(f) Actions with respect to intangible transition charges.--

(1) Nothing in this chapter shall entitle any person to bring an action against a retail electric customer for nonpayment of intangible transition charges, other than the electric utility, its successor or any other entity which provides electric service to a person that was a customer of an electric utility located within the certificated territory

of the electric utility on the effective date of this chapter or that became a customer of electric services within such territory after the effective date of this chapter and is still located within such territory.

(2) The commission has exclusive jurisdiction over any dispute arising out of the obligations to impose and collect intangible transition charges of an electric utility, its successor or any other entity which provides electric service to a person that was a customer of an electric utility located within the certificated territory of the electric utility on the effective date of this chapter or that became a customer of electric services within such territory after the effective date of this chapter and is still located within such territory.

(g) Definitions.--As used in this section, the following words and phrases shall have the meanings given to them in this subsection:

"Assignee." An entity, including a corporation, public authority, trust or financing vehicle, to which an electric utility assigns, sells or transfers other than as security all or a portion of its interest in or right to intangible transition property. The term includes an entity, including a corporation, public authority, trust or financing vehicle to which a direct assignee of an electric utility may assign, sell or transfer other than as security its interest in or right to intangible transition property.

"Financing party." A holder of transition bonds, including trustees, collateral agents and other entities acting for the benefit of such a holder.

"Intangible transition charges." The amounts authorized to be imposed on all customer bills and collected, through a nonbypassable mechanism by the electric utility or its successor or by any other entity which provides electric service to a person that was a customer of an electric utility located within the certificated territory of the electric utility on the effective date of this chapter or that, after this effective date of this chapter, became a customer of electric services within such territory and is still located within such territory, to recover qualified transition expenses pursuant to a qualified rate order. The amounts shall be allocated to customer classes in a manner that does not shift interclass or intraclass costs and maintains consistency with the allocation methodology for utility production plant accepted by the commission in the electric utility's most recent base rate proceeding.

"Intangible transition property."

(1) The property right created under this section representing the irrevocable right of the electric utility or an assignee to receive through intangible transition charges amounts sufficient to recover all of its qualified transition expenses. The term includes all right, title and interest of the electric utility or assignee in the qualified rate order and in all revenues, collections, claims, payments, money or proceeds of or arising from intangible transition charges pursuant to the order to the extent that, in accordance with this chapter, the order and the rates and other charges authorized under the order are declared to be irrevocable.

(2) Intangible transition property shall arise and exist only when, as and to the extent that an electric utility or

assignee has qualified transition expenses for which intangible transition charges are authorized in a qualified rate order that has become effective in accordance with subsection (a) and shall thereafter continuously exist to the extent provided in the order.

"Qualified rate order." An order of the commission adopted in accordance with this section, authorizing the imposition and collection of intangible transition charges.

"Qualified transition expenses." The transition or stranded costs of an electric utility approved by the commission for recovery under sections 2804 (relating to standards for restructuring of electric industry) and 2808 (relating to competitive transition charge) through the issuance of transition bonds; the costs of retiring existing debt or equity capital of the electric utility or its holding company parent, including accrued interest and acquisition or redemption premium, costs of defeasance, and other related fees, costs and charges relating to, through the issuance of transition bonds or the assignment, sale or other transfer of intangible transition property; and the costs incurred to issue, service or refinance the transition bonds, including accrued interest and acquisition or redemption premium, and other related fees, costs and charges, or to assign, sell or otherwise transfer intangible transition property.

"Transition bonds." Bonds, debentures, notes, certificates of participation or of beneficial interest or other evidences of indebtedness or ownership which:

(1) are issued by or on behalf of the electric utility or assignee pursuant to a qualified rate order;

(2) are secured by or payable from intangible transition property; and

(3) reach final maturity in no longer than ten years.

(June 8, 2001, P.L.123, No.18, eff. July 1, 2001)

2001 Amendment. Act 18 amended subsec. (d)(1).

Cross References. Section 2812 is referred to in section 2808 of this title; section 9109 of Title 13 (Commercial Code).

§ 2813. Procurement of power.

Except as provided under the act of November 30, 2004 (P.L.1672, No.213), known as the Alternative Energy Portfolio Standards Act, the commission may not order a default service provider to procure power from a specific generation supplier, from a specific generation fuel type or from new generation only.

(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added section 2813. See the preamble to Act 129 of 2008 in the appendix to this title for special provisions relating to legislative findings and declarations.

§ 2814. Additional alternative energy sources.

(a) Alternative energy sources.--The term "alternative energy sources" as defined under section 2 of the act of November 30, 2004 (P.L.1672, No.213), known as the Alternative Energy Portfolio Standards Act, shall also include low-impact hydropower consisting of any technology that produces electric power and that harnesses the hydroelectric potential of moving water impoundments if one of the following applies:

(1) (i) the hydropower source has a Federal Energy Regulatory Commission licensed capacity of 21 megawatts or less; and

(ii) the license for the hydropower source was issued by the Federal Energy Regulatory Commission on or prior to January 1, 1984, and held on July 1, 2007, in whole or in part by a municipality located wholly within this Commonwealth or by an electric cooperative incorporated in this Commonwealth.

(2) The incremental hydroelectric development:

(i) does not adversely change existing impacts to aquatic systems;

(ii) meets the certification standards established by the Low Impact Hydropower Institute and American Rivers, Inc., or their successors;

(iii) provides an adequate water flow for protection of aquatic life and for safe and effective fish passage;

(iv) protects against erosion; and

(v) protects cultural and historic resources.

(b) Biomass.--The term "biomass energy" as defined under section 2 of the Alternative Energy Portfolio Standards Act shall also include the generation of electricity utilizing by-products of the pulping process and wood manufacturing process, including bark, wood chips, sawdust and lignins in spent pulping liquors. Electricity from biomass energy under this subsection generated inside this Commonwealth shall be eligible as a Tier I alternative energy source. Electricity from biomass energy under this subsection generated outside this Commonwealth shall be eligible as a Tier II alternative energy source.

(c) Increase in Tier I.--The commission shall at least quarterly increase the percentage share of Tier I alternative energy sources required to be sold by an electric distribution company or electric generation supplier under section 3(b)(1) of the Alternative Energy Portfolio Standards Act to reflect any new biomass energy or low-impact hydropower resources that qualify as a Tier I alternative energy source under this section. No new resource qualifying as biomass energy or low-impact hydropower under this section shall be eligible to generate Tier I alternative energy credits until the commission has increased the percentage share of Tier I to reflect these additional resources.
(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added section 2814. See the preamble to Act 129 of 2008 in the appendix to this title for special provisions relating to legislative findings and declarations.

§ 2815. Carbon dioxide sequestration network.

(a) Assessment.--

(1) By April 1, 2009, the department shall complete a study to identify suitable geological formations, including sites within or in proximity to the Medina, Tuscarora or Oriskany Sandstone formation for the location of a State network.

(2) By June 1, 2009, the department, in consultation with the commission, shall hire one or more independent experts pursuant to 62 Pa.C.S. Pt. I (relating to Commonwealth Procurement Code), as necessary, to conduct an assessment of the following:

(i) Estimates of capital requirements and expenditures necessary for the establishment, operation and maintenance of a State network.

(ii) The collection of data to allow a safety assessment.

(iii) An assessment of all potential risk to individuals, property and the environment associated with the geological sequestration of carbon dioxide in a State network. The assessment, which shall be completed by October 1, 2009, shall include an analysis of the following:

(A) Existing Federal and State regulatory standards for the storage of carbon dioxide.

(B) Factors contained in the United States Environmental Protection Agency's Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide (EPA 430-R-08-009, dated July 10, 2008).

(C) The different types of insurance, bonds, other instruments and recommended levels of insurance which should be carried by the operator of the State network during the construction and operation of the State network.

(D) The availability of commercial insurance.

(E) Models for the establishment of a Commonwealth fund to provide protection against risk to be funded by the operator.

(b) Transmission of study and assessment.--

(1) The department shall submit the study conducted under subsection (a)(1) to the Governor, the chairman and minority chairman of the Environmental Resources and Energy Committee of the Senate, the chairman and minority chairman of the Environmental Resources and Energy Committee of the House of Representatives and the department no later than May 1, 2009.

(2) The independent expert shall submit the final assessment under subsection (a)(2) to the Governor, the chairman and minority chairman of the Environmental Resources and Energy Committee of the Senate, the chairman and minority chairman of the Environmental Resources and Energy Committee of the House of Representatives and the department no later than November 1, 2009.

(c) Department.--The following shall apply:

(1) The department shall review the assessment submitted under subsection (a)(2) and all geologic sequestration requirements associated with a State network, including geological site characterization, modeling and verification of fluid movement, corrective action, well construction, operation, mechanical integrity testing, monitoring and site closure.

(2) Following the review under paragraph (1), the department may conduct a pilot project to determine the viability of establishing a State network in this Commonwealth.

(d) Definitions.--As used in this section, the following words and phrases shall have the meanings given to them in this subsection:

"Carbon dioxide sequestration." The storage of carbon dioxide in a supercritical phase within a geological subsurface formation such as a deep saline aquifer with suitable cap rock, sealing faults and anticlines that includes compression, dehydration and leak detection monitoring equipment and pipelines to transport carbon dioxide captured by an advanced coal combustion with limited carbon emissions plant to an underground storage site. The term shall not include use of the carbon dioxide for enhanced oil recovery.

"Department." The Department of Conservation and Natural Resources of the Commonwealth.

"State network." A carbon dioxide sequestration network established on lands owned by the Commonwealth, or lands on which the Commonwealth has acquired the right to store carbon dioxide, that have been designated by the Department of Conservation and Natural Resources for the storage of carbon dioxide.

(Oct. 15, 2008, P.L.1592, No.129, eff. 30 days)

2008 Amendment. Act 129 added section 2815. See the preamble to Act 129 of 2008 in the appendix to this title for special provisions relating to legislative findings and declarations.

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA. 17105-3265

Public Meeting held June 18, 2009

Commissioners Present:

James H. Cawley, Chairman
Tyrone J. Christy, Vice Chairman
Kim Pizzingrilli
Wayne E. Gardner
Robert F. Powelson, Statement

Smart Meter Procurement and Installation Docket No. M-2009-2092655

IMPLEMENTATION ORDER

BY THE COMMISSION:

The Pennsylvania General Assembly ("General Assembly") has directed that electric distribution companies with more than 100,000 customers file smart meter technology procurement and installation plans with the Commission for approval. 66 Pa.C.S. § 2807(f). This Implementation Order will establish the standards each plan must meet and provide guidance on the procedures to be followed for submittal, review and approval of all aspects of each smart meter plan. This Implementation Order will also establish minimum smart meter capability and guidance on the Commission's expectations for deployment of smart meters.

BACKGROUND AND HISTORY OF THIS PROCEEDING

Governor Edward Rendell signed Act 129 of 2008 (“the Act” or “Act 129”) into law on October 15, 2008. The Act took effect 30 days thereafter on November 14, 2008. Among other things, the Act specifically directed that within nine months of its effective date, electric distribution companies (“EDCs”) are to file, with the Commission for approval, a smart meter technology procurement and installation plan. 66 Pa.C.S. § 2807(f)(1). Each EDC smart meter plan must describe the smart meter technologies the EDC proposes to install, upon request from a customer at the customer’s expense, in new construction and in accordance with a depreciation schedule not to exceed 15 years. 66 Pa.C.S. §§ 2807(f)(1) and (2). The Act also establishes a requirement for EDCs to make available to third parties direct meter access and electronic access to meter data by third parties, upon customer consent. 66 Pa.C.S. § 2807(f)(3). The Act further defines minimum smart meter technology capabilities. 66 Pa.C.S. § 2807(g). Finally, the Act establishes acceptable cost recovery methods. 66 Pa.C.S. § 2807(7).

On March 30, 2009, the Commission issued a Secretarial Letter seeking comments on a draft staff proposal and additional questions regarding EDC smart meter procurement and installation. Comments were due by April 15, 2009, with reply comments due April 27, 2009. On April 9, 2009, the Commission, at the request of several interested parties, issued a Secretarial Letter extending the comment period to April 20, 2009 and the reply comment period to April 29, 2009.

The following parties filed comments: West Penn Power Company d/b/a Allegheny Power (“Allegheny”); Citizen Power (“Citizen”); Constellation NewEnergy, Inc. (“Constellation”); Duquesne Light Company (“Duquesne”); Elster Integrated Solutions (“Elster”); The Energy Association of Pennsylvania (“EA”), Exelon Energy (“Exelon”); Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company (collectively “FirstEnergy”); the Industrial Energy Consumers of Pennsylvania (“IECPA”); Office of Consumer Advocate (“OCA”); PECO Energy Company (“PECO”); PPL Electric Utilities Corporation (“PPL”); Sensus Metering Systems (“Sensus”); Tendril Networks, Inc. (“Trendril”); and Trilliant, Inc. (“Trilliant”). The following parties filed reply comments: Duquesne; EA; FirstEnergy; IECPA; PECO; and PPL.[1]

DISCUSSION

In this section the Commission will outline the standards each plan must meet and provide guidance on the procedures to be followed for submittal, review and approval of all aspects of each smart meter plan. This section will also establish guidance on the Commission’s expectations for the deployment of smart meters, as well as minimum smart meter capabilities. This section will also describe requirements regarding access to smart meters and data. Finally, in this section the Commission will provide guidance on EDC smart meter technology cost recovery.

A. Plan Approval Process

Within nine months after the effective date of Act 129, each EDC with more than 100,000 customers is to file a smart meter technology procurement and installation plan with the Commission for approval. 66 Pa.C.S. §§ 2807(f)(1) and (6). As Act 129 became effective on November 14, 2008, the smart meter plans must be submitted on or before August 14, 2009. Each smart meter plan shall include: a summary of the EDC’s current deployment of smart meter technology, if any; a plan for future deployment,

[1] Wal-Mart Stores East, LP and Sam’s East Inc. filed a Petition for Extension of Time to file reply comments, which this Commission denied in a letter dated May 6, 2009. While we rejected Wal-Mart’s and Sam’s petition, we did receive and consider their reply comments submitted on May 1, 2009.

complete with dates for key milestones and measurable goals; and such other information as is required by this Order. The plans shall be served on the Office of Consumer Advocate, the Office of Small Business Advocate, the Office of Trial Staff, and Electric Generation Suppliers licensed to provide service in the Commonwealth.

Comments to the smart meter plans will be permitted to be filed by September 25, 2009. Following the receipt of comments, the plans will be referred to the Office of Administrative Law Judge for such proceedings as may be deemed necessary. There will be at least one technical conference scheduled for each plan during October, 2009, at which the filing EDC will present personnel with in-depth knowledge of the plan who can respond to questions regarding all aspects of the plan. The technical conference(s) shall be transcribed and the transcript(s) will become part of the record in the proceeding.[2] Any evidentiary hearings that may be necessary shall be held during November 2009.

At the conclusion of the technical conference and any evidentiary hearings that may be necessary, an initial decision will be issued resolving all issues raised in the proceeding. It is anticipated that an Initial Decision will be issued on or before January 29, 2010. Parties will be permitted to file Exceptions and Reply Exceptions as set forth in Section 5.533 of the Commission's Regulations, 52 Pa. Code § 5.533. Parties are strongly encouraged to pursue settlement opportunities during the proceeding. It is expected that the comments and technical conference(s) will promote settlement efforts.

Several parties provided comments on the staff proposal's plan approval process. The EA asserted that the plan approval process should be a collaborative process rather

[2] Any technical conference should be conducted as informally as possible, consistent with the good order of the proceedings. Lay persons will be permitted to directly ask questions of the EDC representatives, although such lay persons must be affiliated with an admitted Party of Record.

than an adversary proceeding. We note that, after smart meter plans are referred to the OALJ, the proceedings will be conducted in accordance with the Commission's Rules of Administrative Practice and Procedure. This does not mean that the plan approval process must be a contentious adversary proceeding. We encourage parties to seek collaborative solutions to issues that arise during the plan approval process. Nevertheless, due process considerations require that we preserve the right of the parties to litigate if cooperative solutions cannot be reached and obtain an adjudication from the Commission.

Several commenters, including the OCA, expressed concern that the plan approval process described in the staff proposal did not provide adequate time for review of smart meter plans. They noted that Act 129 does not prescribe the period for reviewing and approving smart meter plans. Consequently, they argued that the plan approval process can and should be extended so that the review of smart meter plans is not unduly constrained.

In addition, the OCA and other commenters asserted that the proposed plan approval process should be modified to improve coordination with other proceedings required by Act 129. They point out that, under the plan approval process as described in the staff proposal, comments would be due and technical conferences would be held during August and September, 2009. During that same period, the EDCs, the statutory advocates, the ALJs and many other interested stakeholders will be engaged in Act 129 proceedings regarding Energy Efficiency and Conservation Plan approvals. These commenters conclude that the plan approval process should be modified so that it is better integrated with Energy Efficiency and Conservation Plan approvals.

Allegheny, on the other hand, asserted that Initial Decisions should be issued quickly due to the time necessary to implement plans following their approval. In addition, Duquesne expressed its support for the plan approval process described in the staff proposal.

While the Commission agrees with the need to complete the plan approval process expeditiously, we are persuaded that the process, and its results, will be improved considerably if we extend the time period for reviewing and approving plans. We will not, however, adopt OCA's proposal as that proposal does not provide the ALJs with adequate time to prepare an initial decision following the receipt of briefs and reply briefs in December 2009.

Accordingly, as outlined above, we will require smart meter plans to be filed with the Commission on or before August 14, 2009. Comments may be filed with the Commission on or before September 25, 2009. Technical conferences will be held during October 2009, with evidentiary hearings, if necessary, to be held during November 2009, and Initial Decisions to be issued on or before January 29, 2010. Any party may file Exceptions and/or Reply Exceptions to the Initial Decisions, in accordance with Commission Regulations, before the Commission issues its final decision.

B. Smart Meter Deployment

Act 129 requires EDCs to furnish smart meter technology (1) upon request from a customer that agrees to pay the cost of the smart meter at the time of the request, (2) in new building construction, and (3) in accordance with a depreciation schedule not to exceed 15 years. 66 Pa.C.S. § 2807(f)(2). The Commission recognizes that a fully functional smart meter involves more than just the meter hardware attached to the customer's premises. A fully functional smart meter that supports the capabilities required by Act 129 and as outlined below, involves an entire network, to include the meter, two-way communication, computer hardware and software, and trained support personnel. The Commission also recognizes that it may take time for EDCs to select and install the required smart meter network components, and to train support personnel.

1. Network Development and Installation Milestones

As EDCs will need time to develop and install the entire smart meter network, the Commission is granting a network development and installation grace period of up to 30 months following plan approval. During this grace period the Commission will not require EDCs to install a smart meter at a customer's premises. However, during this grace period, the Commission will require EDCs to provide interval data capable meters, if the existing meter is not capable of providing interval data, and direct access to the customer's interval data to third-parties, such as EGSs or CSPs, upon customer request.[3] The access to this interval data should be available in real-time, if requested, and in a manner consistent with RTO requirements. In addition, EDCs will be permitted to continue to offer their already established and approved time-of-use rate programs.

The Commission also directs all covered EDCs to include in their smart meter procurement and installation plan filing a proposal for meeting specific milestones within this 30 month grace period. Each covered EDC must include a justification and its plan for meeting the following milestones:

- Assessment of needs and technological solutions.
- Selection of technologies and vendors.
- Establishment of network designs.
- Establishment of plans for training personnel.

[3] These interval capable meters are not smart meters as they will not have the capabilities outlined below in Section C of this Order. However, they are capable of providing real-time pulse data that enables the recording of usage at set intervals.

- Establishment of plans for installation, testing and rollout of support equipment and software.
- Installation, testing and rollout of support equipment and software.
- Establishment of plans to design, test and certify EDI transaction capability consistent with this order.
- Establishment of plans for installation of meters consistent with the rollout requirements described below.

Each plan must include a schedule to meet each of these milestones, as well as specific reporting deadlines when the EDC will provide this Commission with reports on the status of its plan.

Several commenters provided input regarding the proposed 18 month network development and installation grace period. Overall, the topic of an 18 month grace period was the issue that generated the most consensus. The general take on the issue was that 18 months was not nearly enough time for the EDCs to have their smart meter networks up and running. Among those holding this position was: the EA, Allegheny, PPL, FirstEnergy, PECO, and Duquesne. Specifically, PPL noted that just the selection and procurement process for the meters would take 18 months, while a separate 18 month period would be required for planning and development associated with meter data management and an additional couple of years for the installation and integration of such systems.

FirstEnergy urged the Commission to remain flexible with its timelines, due to the inherent differences of the EDCs' service territories and starting points. The EA, FirstEnergy and PECO asserted that the 18 month grace period should not commence until a vendor contract is approved. PECO anticipated delays in the marketplace due to the high number of EDCs purchasing smart meters and network equipment at the same time and suggested delaying the start of the grace period until a final vendor contract is signed and approved. The EA supports the use of key goals and milestones for each EDC and encourages flexibility of such goals, as all EDCs are unique.

It seems clear that the suggested 18 month grace period is not a sufficient amount of time for the EDCs to design and install their smart meter networks. The Commission agrees that some flexibility must be provided in the design and installation of a smart meter network, as some EDCs face greater logistical challenges than others do. Therefore, the Commission has established a period of up to 30 months for each EDC to assess its needs, select technology, secure vendors, train personnel, install and test support equipment and establish a detailed meter deployment schedule consistent with the statutory requirements. This grace period will commence upon Commission approval of an EDC's smart meter plan. This will afford each EDC more time and flexibility in the design and development process to ensure that it can meet the demands and challenges unique to each service territory.

2. Customer Request

As pointed out above, the Commission will not require EDCs to deploy smart meters until after the EDC's Commission approved network development and installation grace period ends. Once this grace period expires, each covered EDC must supply a smart meter upon request by a customer, per Act 129.

The Commission recognizes that deployment of smart meters on a piecemeal or individual basis could involve greater costs than a systematic system-wide deployment. The General Assembly recognized this as well when it included the proviso that the customer requesting the smart meter must agree to pay for the cost of the smart meter. However, the Commission does not believe it was the intent of the General Assembly for this customer to pay the entire cost of the smart meter and its supporting infrastructure.

Such a requirement would be so cost-prohibitive that no customer would request a smart meter. Furthermore, the customer would be paying for the smart meter directly and also through the EDC's cost recovery mechanism. Such a result would be an absurd, impossible and unreasonable outcome, which is contrary to the rules of statutory construction. See 1 Pa.C.S. § 1922(1). To avoid this absurd result, the Commission believes that only the incremental costs over and above the cost for system-wide deployment are to be paid by customers requesting early deployment of a smart meter.

The Commission directs each covered EDC to include in its smart meter plan a proposal to install individual smart meters in advance of the EDC's system-wide deployment and after the network installation grace period. This proposal should include an itemization of the incremental costs. If an EDC cannot provide the incremental costs at the time of its initial filing, it will have to seek Commission approval of these incremental charges prior to the expiration of the approved network grace period. If an EDC does not obtain approval of these incremental costs prior to the end of the grace period it must install individual smart meters at its own expense. Such costs are not recoverable from ratepayers.

Several commenters expressed concerns regarding the costs associated with installing smart meters at customer request pursuant to 66 Pa.C.S. § 2807(f)(2)(i). OCA agreed that a customer should pay for the incremental costs of installing a meter prior to the scheduled rollout. However, OCA does not feel that the customer should have to provide payment upfront to cover the costs, but rather the costs should be recovered through an increased customer charge on the customer's monthly bill. OCA also warns that care must be taken to ensure that the customer is not being subjected to any sort of double recovery. PECO and FirstEnergy maintain that the customer must pay these costs as a lump sum at the time of the request, as stated in Act 129.

FirstEnergy submits that 52 Pa. Code § 57.20(h) provides that "a service watt-hour meter which is removed from service shall be tested for 'as found' registration accuracy." FirstEnergy requests that the Commission provide EDCs with a blanket waiver of this requirement, as the meters are not being replaced due to any perceived malfunction and will not be put back into service. FirstEnergy posits that such a waiver will eliminate unnecessary costs associated with system-wide smart meter installation.

Duquesne states that the incremental costs to an individual customer would be astronomical because reading the new meters without having deployed the entire infrastructure would require the purchasing of trucks and the hiring of meter readers and administrative office workers to manually enter the meter reads.

The Commission interprets the Act to mean that a customer must pay the costs of installing a meter at the time of the request, and hence disagrees with OCA's assertion that the costs should be embedded in a customer charge. The EDC needs to be reimbursed for the task of installing a meter on a piecemeal basis, and the easiest way to accomplish that recovery is not through a customer charge increase, but rather by receiving an upfront payment from the customer.

As for Duquesne's worry about the incremental costs being astronomical, the Commission believes there is confusion when Duquesne says it is worried about reading meters before the new infrastructure is in place. The Commission is not requiring an EDC to do anything extraordinary during this smart meter procurement and installation grace period. The requirement to install interval capable meters during the grace period or smart meters at the request of a customer is intended to support rate structures, energy efficiency or demand response programs offered by the EDC or a third party at the request of a customer. These types of programs have been in place and offered to customers for decades. All the Commission is requiring is that EDCs facilitate these programs in a cost effective manner that provides access to the data needed to support these programs without unnecessary or unreasonable barriers. Therefore, the Commission expects the EDCs to provide a plan for supporting these programs in such a manner that does not require unreasonable or imprudent costs. Furthermore, all incremental costs that EDCs plan on recovering from a customer must first be reviewed and approved by the Commission. Staff believes these costs will be reasonable and by no means astronomical.

The Commission agrees with FirstEnergy that the costs of complying with 52 Pa. Code § 57.20(h) are unnecessary and will grant a waiver of this provision for watthour meters that are being replaced with smart meters in accordance with an approved plan. The Commission believes it would add unreasonable and unnecessary costs to require the EDCs to test every meter removed for the purposes of upgrading to a smart meter.

3. New Construction

As with all equipment, meters have a useful life. EDCs determine how much to invest in meter equipment based on its useful life and have an opportunity to depreciate that investment over the useful life of the meter. In addition, EDCs have an opportunity to recover the cost of the meter from ratepayers. Therefore, if a meter is replaced prior to the end of its useful life, the EDC will not be able to take advantage of the full depreciation of that meter or the ratepayers will pay an increased rate to cover the cost of both meters. The Commission believes that the intent of the Act’s provision for installing smart meters in new construction was to avoid this waste and added expense.

Again, the Commission will not require deployment of smart meters in new construction during an EDC’s approved network grace period. However, the Commission will direct all covered EDCs to develop a plan to install smart meters in new construction that is begun after the network grace period. Therefore, the Commission directs each covered EDC to include in its smart meter plan a proposal for deployment of smart meters in new construction. Such a proposal should include a plan to identify new developments and construction early enough to incorporate it into the system-wide deployment proposal.

Several parties commented on the proposed rollout of smart meters in new construction. OCA posits that smart meters should be installed on new construction from the beginning, even during the network installation grace period. OCA asserts that while the smart meters will not be fully functional, the smart meters should still be able to provide the necessary billing data. FirstEnergy, PECO and PPL disagree, noting that while the meter may be able to provide billing data, the method for providing that data may not be compatible with its existing systems. FirstEnergy does not object to providing smart meters on new construction after the grace period, provided that the Commission allows for flexibility in making the smart meters fully functional and that the customer pays the incremental costs. Duquesne asserted that installation of smart meters should be addressed in the same manner as installation at customer request. Duquesne notes that customer preference should determine which meter to install between the end of the grace period and system-wide deployment.

The Commission agrees with FirstEnergy, PECO and PPL that installation of smart meters on new construction during the grace period would not be practical or cost-effective as the EDCs will not have selected the technology they will employ. Furthermore, the smart meter may not be compatible with its existing meter reading technology. As such, the Commission directs EDCs to handle any new construction customer that requests a smart meter during the grace period pursuant to the procedures addressed above for customer requested meters.

4. System-Wide Deployment

The Commission believes that it was the intent of the General Assembly to require all covered EDCs to deploy smart meters system-wide when it included a requirement for smart meter deployment "in accordance with a depreciation schedule not to exceed 15 years." It is this system-wide deployment that will provide the foundation for the EDCs' smart meter installation plans. Therefore, it is crucial for the EDCs to develop a plan that will best meet the needs of their service territory, while at the same time operating in a manner that is both cost and time effective.

The EDCs shall detail their system-wide deployment plans to the Commission, including any type of tiered rollout the company proposes, as well as the associated costs and benefits incurred from such a rollout. This system-wide plan should also incorporate a coordination element with the new construction deployment component. Furthermore, the Commission will require all EDCs to file a "Smart Meter Progress" report on an annual basis that will update the status of their installation plans, including the number of customers who received meters in the prior year, the estimated number of customers scheduled to receive meters in the coming year, and all costs associated with the meter plan incurred during the previous year.

It should also be noted that Act 129 uses the language "not to exceed 15 years." An EDC is encouraged to expedite the deployment process if it will provide increased customer benefits in a cost-effective manner. Again, the primary goal of the EDC deployment plan should be to implement a deployment and installation schedule that best balances the overall efficiency and timeliness of the smart meter installations with the costs incurred.

OCA commented that the Commission needs to clarify whether the 15 year depreciation schedule outlined in Act 129 commences upon plan approval or following the grace period. The Commission believes that the 15 year depreciation period should commence upon plan approval, and that the grace period is simply a period of time within that 15 year timeframe.

C. Smart Meter Capabilities

Act 129 defines smart meter technology as including metering technology capable of bidirectional communication that records electricity usage on at least an hourly basis, including related electric distribution system upgrades to enable the technology. 66 Pa.C.S. § 2807(g). The Act further states that the smart meter technology must provide customers with direct access to and use of price and consumption information, to include, (1) direct information on their hourly consumption, (2) enable time-of-use rates and real-time price programs, and (3) effectively support the automatic control of electricity consumption by, the customer, the EDC or a third-party, at the customer's request. 66 Pa.C.S. § 2807(g).

The Act further requires that default service providers submit time-of-use rates and real-time pricing plans by January 1, 2010, or at the end of the applicable generation rate cap period, whichever is later. Default service providers must offer the time-of-use rates and real-time pricing plans to all customers that have been provided with smart meter technology. 66 Pa.C.S. § 2807(f)(5). Real-time pricing is defined as "a rate that directly reflects the different cost of energy during each hour." 66 Pa.C.S. § 2806.1(m). A time-of-use rate is defined as "a rate that reflects the costs of serving customers during different time periods, including off-peak and on-peak periods, but not as frequently as each hour." *Id*.

The Commission believes that the smart meter capability requirements set out in Act 129 are minimal requirements. The Commission also recognizes that smart meter technology can support more than demand response and pricing programs. Smart meters have the ability to support maintenance and repair functions, theft detection, system security, consumer assistance programs, customer-generator net metering, and other programs that increase an EDC's efficiencies and reduce operating costs. Therefore, the Commission directs that a covered EDC's smart meter technology must support the following capabilities:

1. Bidirectional data communications capability.
2. Remote disconnection and reconnection.
3. Ability to provide 15-minute or shorter interval data to customers, EGSs, third-parties and the regional transmission organization ("RTO") on a daily basis, consistent with the data availability, transfer and security standards adopted by the RTO.
4. A minimum of hourly reads delivered at least once per day.
5. On-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as ANSI C12.19 and C12.22 tables.
6. Open standards and protocols that comply with nationally recognized non-proprietary standards, such as IEEE 802.15.4.
7. Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible.
8. Ability to monitor voltage at each meter and report data in a manner that allows EDC to react to the information.
9. Remote programming capability.
10. Communicate outages and restorations.
11. Ability to support net metering of customer-generators.

12. Support automatic load control by EDC, customer and third-parties, with customer consent.
13. Support time-of-use and real-time pricing programs.
14. Provide customer direct access to consumption and pricing information.

While the Commission believes that all of the above-listed capabilities will further facilitate the consumer's ability to intelligently control their electric use and costs, we are cognizant that the costs of some of these added capabilities may exceed any benefit they may provide. Therefore, the Commission reserves the authority to waive the requirement for any of the Commission imposed requirements as described in Section E.1 below. This waiver authority does not extend to the minimum requirements delineated in 66 Pa.C.S. § 2807(g).

Several commenters provided input regarding the smart meter capabilities listed in the staff proposal. We will address each of the major issues raised by commenters relating to smart meter capabilities.

1. Remote disconnect, reconnect, service limiting and pre-pay capabilities

In their comments, Allegheny and PECO favor requiring smart meters to support remote disconnect and reconnect, as well as service limiting and prepaid service programs. Duquesne supported remote disconnect and reconnect for single phase, self-contained and class 200 or less meters, but suggested that revisions to Chapter 56 need to be considered before committing to these capabilities. PPL noted that there are institutional impediments to deployment of remote disconnect and reconnect capability. In addition, PPL and OCA noted that remote disconnect and reconnect, as well as, service-limiting and pre-pay functionality involves significant public policy considerations that raises process and safeguard issues. OCA is further concerned that by requiring smart meters to support remote disconnect, service limiters and prepaid service sends a strong signal to EDCs to implement these capabilities. OCA specifically stated that "the use of smart meter technology to terminate customers, limit service, or require prepayment of service raise significant concerns for the health and safety of the residents of the Commonwealth."[4]

The Commission agrees in part with Allegheny, OCA, PECO and PPL. Specifically, the Commission agrees that the significant policy implications of service limiting and prepaid service should be addressed in another proceeding prior to requiring such capability in smart meters. Therefore, we have removed support for service-limiting, and prepaid service as a minimum capability requirement. This does not preclude EDCs from including these capabilities, however, an EDC cannot employ these capabilities unless it is approved by the Commission and consistent with regulations governing such programs, such as 52 Pa. Code § 56.17.

The Commission does not believe that the same policy uncertainties exist with regard to remote disconnect and reconnect. The policy issues and procedures regarding termination and reconnection of service are addressed in the Public Utility Code ("Code"), at 66 Pa.C.S. §§ 1401-1418 and this Commission's regulations. Requiring the ability to remotely disconnect and reconnect service in no way abrogates an EDC's obligation to adhere to the Code or this Commission's regulations. Therefore, the Commission will require that smart meters have a capability to remotely disconnect and reconnect service as it provides the ability to increase safety, efficiency and cost benefits.

[4] OCA Comments at page 10.

Ability to provide 15-minute reads

Duquesne, FirstEnergy, PECO, PPL and OCA do not support the inclusion of 15-minute or shorter interval data capability. Instead the parties support hourly data intervals. Duquesne supports hourly and real time pulse data. OCA and PECO assert that the 15-minute or shorter requirement goes beyond Act 129. PECO notes that this requirement is not practical or useful for residential or small commercial customers and that mandating collection of this data may result in increased costs with no benefits. PPL adds that there is less need today than in the past for 15-minute interval data as settlements are conducted on an hourly basis.

However, PPL also recognized that some demand side management programs require less than hourly data intervals. To accommodate this limited group of customers, PPL recommended that the Commission direct that EDC Smart Meter Plans demonstrate how this need will be met. An example offered by PPL involves access protocols for parties to obtain pulse data when hourly data is not sufficient.

Constellation, Elster and Trilliant support the inclusion of the 15-minute or shorter interval data capability. Constellation contends that each meter should be programmable so that a 1-, 5-, 15-, 30- or 60-minute interval could be set. This interval should be based on customer requirements rather than administratively set by the Commission. Elster notes that typical residential systems are capable of providing 15-minute interval data. The interval selected may be more or less frequent depending on specific utility application. Trilliant adds that systems should be configurable to intervals between 5- and 60-minutes. Elster, however, notes that the shorter data intervals will increase costs.

The Commission agrees with Constellation, Elster and Trilliant and concludes that the ability to provide 15-minute or shorter interval data is appropriate. We stress however, that the ability to provide 15-minute or shorter interval data does not mean that EDCs must collect this data on all customers at all times. The ability to provide 15-minute or shorter interval data will allow for EDCs and third parties with customer consent to offer and support rate plans that utilize this level of granularity. The Commission will therefore require that EDC smart meter plans demonstrate how the need for 15-minute or shorter data intervals will be met.

2. Meter storage

Duquesne supports on board meter storage of meter data that complies with nationally recognized non-proprietary standards without specifying one particular standard. FirstEnergy supports ANSI C12.22 and C12.19 or their equivalents. PPL indicates that standards should be followed as appropriate, but questions why it is necessary to follow standard protocol for storage in the meter that is unlikely to be communicated anywhere but the EDC repository.

The Commission agrees with FirstEnergy and has added the ANSI C12.22 standard. The ANSI C12.19 and C12.22 are standards for storage and transport of register data over a network. The Commission is aware that a number of factors including memory size, number of data channels being recorded and interval length can impact the number of storage days. The intent of a minimum number of storage days is to ensure that adequate monthly billing data is retrieved before the data is overwritten. Therefore, rather than reference a specific number of days, the Commission requires that EDC smart meter plans incorporate provisions ensuring that all billing data is retrieved before data is overwritten and recoverable following communications outages.

3. Open standards and protocols

Tendril suggests that the Commission should accept any nationally recognized, non-proprietary standard. Trilliant adds that protocols should be focused at a high level, such as IEEE 802.15.4 (open standard for radio technology). Allegheny notes, for example, that ZigBee is built upon this standard. Elster, however, emphasizes that there is more than one protocol. Duquesne cites the existence of 14 HAN solutions, open or otherwise. The Commission agrees that protocols should be focused at a high level, such as IEEE 802.15.4, and therefore, directs compliance with this standard. The Commission also encourages EDCs to adopt other open protocols and standards that enhance interoperability that are developed subsequent to this order, to the extent available at the time the vendor contract is solicited.

4. Upgradability

Duquesne suggests that technology should be evaluated to accommodate future upgrades, noting that some capabilities can be upgraded as technology advances and becomes economically feasible, while other capabilities are costly to implement without complete meter and system replacement. Duquesne emphasizes that it is difficult to implement a system now to accommodate unknown technical advances. Similarly, PPL notes that it is more important to build flexibility into smart meter systems than it is to anticipate every future need.

The Commission agrees with Duquesne that some capabilities can be upgraded as technology advances and becomes economically feasible, while other capabilities are costly to implement without complete meter and system replacement. The Commission, therefore, directs that EDC smart meter plans identify capabilities that have the potential to be upgraded without complete system replacement as technology advances and becomes economically feasible.

5. Ability to monitor voltage

PPL asserts that it is premature to assume that voltage monitoring has value and that an operations management system and remotely controlled equipment exists to make use of the data. PPL adds that this capability may be appropriate in certain evolutions of the smart grid. The Commission disagrees with PPL in that this feature will serve to enhance reliability aspects associated with the grid. The Commission, therefore, will require that smart meters have a capability to support the ability to monitor voltage.

6. Direct access to consumption and pricing information

Allegheny noted that most smart metering vendors support two standards for a home-area-network (“HAN”) protocols, proprietary and ZigBee. Duquesne recommended that usage information should be validated and made available within 48 hours through a HAN or internet. Duquesne also recommended that the pricing information should reflect the tariff rate and be made available through the internet or HAN. FirstEnergy commented that pricing information should be provided through the internet, noting that HAN type devices will be a competitive offering that should not be dictated by regulation. FirstEnergy and PECO also recommended that validated usage data should be made available in a minimum of 48 hours. PECO posits that data from the meter to a HAN device be limited to raw consumption data. Tendril comments that the Commission should not establish a single standard protocol for delivery of usage information, noting that this information should be available through any and all means that match customer preferences. Regarding pricing data, Tendril encourages a reliance on open standards such as the Smart Energy Profile data standard established by the ZigBee Alliance.

Regarding the comments related to validated consumption data, the Commission agrees in part with FirstEnergy and PECO. We accept that this data should be made available to customers or their designated third-parties within 48 hours, but we adopt this as a minimum standard, at least initially. Ideally, as noted by various parties, the information should be available the next day. Allegheny has already proposed to do this in 24 hours and FirstEnergy noted a 48 hour delay could be shortened as experience is gained.

Regarding comments on the use of open standards and protocols for meter connectivity with other devices, the Commission will not require compliance with one set of standards. Nor will we establish a new standards working group but will instead allow the industry to continue to develop uniform standards for communications firmware and software that would impact consumer products and services in the marketplace. However, the Commission will require EDC smart meters to have a capability to provide raw near real-time consumption data through a HAN or similarly capable method with open protocols. This delivery method should also be capable of providing pricing signals to support real-time and time-of-use pricing programs, as well as energy efficiency and demand response programs. Smart meters should support EDC and EGS time-of-use and real-time-pricing programs. Similarly, smart meters should support EDC, EGS and CSP energy efficiency and demand response programs. An EDC should not use these systems to gain competitive advantage for only its pricing and demand response programs.

D. Access to Smart Meters and Data

Act 129 requires EDCs to make available to third parties, including electric generation suppliers and providers of conservation and load management services, with customer consent, direct access to the meter and electronic meter data. 66 Pa.C.S. § 2807(f)(3). The Commission believes that the true usefulness of smart meters is to provide information to empower customers to control their electric use, for knowledge itself is power.[5]

In order for customers to be empowered they, or their designated representatives, must have direct access to their consumption data and price data. Therefore, the Commission directs that all covered EDCs must provide at least the following access to their smart meters and data:

1. Non-discriminatory access for retail electric suppliers and third-parties, such as EGSs, and conservation and load management service providers;
2. Open, non-proprietary two-way access for electric suppliers and third-parties, such as EGSs, and conservation and load management service providers; and
3. Full electronic access to customers and their representatives to meter data upon customer consent.

The Commission further directs that each EDC plan must address standards and formats for electronic data communications with customers and third parties. There are many approaches for requesting and providing meter-level data today, e.g. electronic bulletin board, pass-key protected websites, compact disk, etc. In addition, EDI (ASC X12 standards) capability has been built by the electricity industry in the Commonwealth to facilitate a reliable, secure economic approach for communicating verified customer

[5] Francis Bacon.

data for electric choice. Regardless of the standard or format identified, compliance with Commission orders relating to electronic data communications and the approved Internet protocol at Docket No. M-00960890F0015, is required for third-party access to verified EDC meter data. The third-party must be EDI tested and certified with the EDC and is free to transcribe that data into any format to meet the customer's specific needs.

In order to achieve the capabilities of smart meter technology, however, EDCs are required to implement an EDI transaction relating to enrollment of customers who elect service on a real-time-price or time-of-use rate program, and a new historical interval usage transaction in order to provide customers and their designated agents with 12 months of interval usage data pursuant to Commission orders at Docket No. M-00960890F0015. Also, the historical usage data transaction must facilitate third-party exchange of historical interval usage data recorded at the meter level. An EDI transaction will also need to be developed and implemented for the exchange of monthly, billing quality, interval usage data recorded at the meter level versus the current practice of providing usage data at the account level. These and other developments necessary for the implementation of smart meter technology plans require EDC and third-party participation in the Commission's Electronic Data Exchange Working Group ("EDEWG"). Therefore, EDCs are directed to propose EDI capabilities for this purpose through the EDEWG for Commission review no later than January 1, 2010. In developing these proposals, EDCs are encouraged to look at any applicable national standards, such as those developed by the North American Energy Standards Board. EDCs shall identify in their plans target dates for the testing and certification of these EDI transactions with their business partners in order to meet the smart metering implementation deadline as specified in this Order.

In general, most commenters who addressed the direct meter access issue agree that allowing direct access to the meter itself raises security and safety concerns. PPL commented that communications are separate from metering company responsibilities and is concerned that the term "direct access" can be interpreted as direct access to raw unvalidated data. Citizen stated that smart meter information should be accessible to customers from a website and directly from the meter, if not cost prohibitive. Duquesne supports direct access to and use of price and consumption information, but does not support direct access to its meters for security reasons. FirstEnergy posits that access to the meter should be strictly prohibited, but that access to the meter data should be permitted under conditions that protect privacy and security. FirstEnergy also encourages the adoption of nationally recognized standards and protocols. PECO expressed a concern about network security and management risks and does not want a mandate that provides customers and third-parties unrestricted access to the EDC's metering network.

Constellation noted that curtailment service providers and EGSs require direct access to the meter to poll interval data and that should not be burdened by installing their own equipment to collect this data. Exelon suggests that there should be consistency across service territories regarding technological capabilities, protocols and processes. Tendril commented that direct, near real-time access to information is critical and that it is extremely important to accommodate two-way communication through the meter interface.

In response to comments on this issue, the Commission interprets the phrase, "make available direct meter access and electronic access to customer meter data," at 66 Pa.C.S. § 2807(f)(3), as the customer's or customer designated third-party's ability to receive price and meter data in a timely manner and format that is useful and beneficial to the customer in terms of cost and value. Examples of customer benefits from direct access may include, but not be limited to, direct load control, automated appliance control and demand response pricing through the grid.

Additionally, the Commission notes that the EDC, who owns the meter, is responsible for providing direct access through the installation of a smart meter and infrastructure that will enable the end user to receive metered price and consumption information, at least in near real-time and in a format that is not proprietary or unduly discriminatory. Many industry standards groups are engaged in addressing and defining business practices and requirements for smart metering products, services and open data communications that will preserve the integrity, reliability and security of the national grid, the local distribution system and the consumer's data. The National Institute of Standards Technology, the North American Energy Standards Board, and the Utility Communications Architecture International Users Group are worthy of EDC participation for achieving the smart metering requirements of Act 129. Therefore, we direct EDCs to adhere to common industry and communications standards for providing consumers direct access to smart meters and data pursuant to this Order.

Nevertheless, for security reasons we determine that a distinction should be made between access to the physical meter and access to the meter information, and we will not require EDCs to allow customers and their designated agent to tamper or physically access the meter itself. However, this directive is not intended to preclude third-parties, with customer consent, from obtaining raw meter data through meter pulse leads, a secure web-portal or other secure means reasonably available to the customer or designated third-party. We agree with the OCA and Sensus that some residential and small commercial customers may find it beneficial to receive consumption and pricing information, and in this regard we will require all EDCs to install a smart meter that is capable of communicating raw data on at least a near real-time basis to in-home devices installed by the customer or customer designated agent. Additionally, we will require EDCs to provide all customers and their designated third-parties access to the following: validated, bill quality consumption data within 48 hours of the meter read; written detailed disclosure of data definitions and characteristics; and written update notices of changes in data characteristics as the changes become effective.

E. EDC Cost Recovery

Act 129 allows an EDC to recover reasonable and prudent costs of providing smart meter technology, to include annual depreciation and capital costs over the life of the smart meter technology and the cost of any system upgrades required to enable the use of the smart meter technology, incurred after November 14, 2008, less operating and capital cost savings realized by the electric distribution company from the installation and use of the technology. Smart meter technology is deemed to be a new service offered for the first time under Section 2804(4)(vi).

1. Cost Recovery Mechanism

An EDC may recover smart meter technology costs through (1) base rates, including a deferral for future base rate recovery of current basis with carrying charge as determined by the Commission; or (2) on a full and current basis through a reconcilable automatic adjustment clause under Section 1307. 66 Pa.C.S. § 2807(f)(7). However, in no event shall lost or decreased revenues by an EDC due to reduced electricity consumption or shifting energy demand be considered a cost of the smart meter technology recoverable under a reconcilable automatic adjustment clause under Section 1307(b), except that decreased revenues and reduced energy consumption may be reflected in the revenue and sales data used to calculate rates in a subsequent distribution rate base rate proceeding filed under Section 1308 (relating to voluntary change in rates), or a recoverable cost. 66 Pa.C.S. § 2807(f)(4).

Act 129 allows an EDC to recover "all reasonable and prudent costs of providing smart meter technology." In order to determine what these costs are, each EDC will document all costs relating to its smart meter deployment and installation plan. These costs will include both capital and expense items relating to all plan elements, equipment and facilities, as well as an analysis of all related administrative costs. More specifically, these costs would include, but not be limited to, capital expenditures for any equipment and facilities that may be required to implement the smart meter plan, as well as depreciation, operating and maintenance expenses, a return component based on the EDC's weighted cost of capital, and taxes. Administrative costs would include, but not be limited to, incremental costs relating to plan development, cost analysis, measurement and verification, and reporting. In addition, the plan should include cost estimates for testing, upgrades, maintenance and personnel training. The EDC must also provide sufficient support to demonstrate that all such costs are reasonable and prudent with respect to its smart meter plan. Consistent with Section 315(a), the burden of proof shall be on the EDC. 66 Pa.C.S. § 315(a).

The Commission recognizes that some of the requirements for smart meters outlined in Section C of this Order go beyond the minimum requirements set forth in Act 129. In order to ensure that these additional smart meter functions are cost-effective, we direct that each smart meter plan filing include cost data that quantifies the costs to meet the minimum requirements set forth in Act 129, the costs to meet all of the requirements set forth in Section C above, and the individual incremental costs of each added function, less any operating and capital cost savings. Specifically, we direct that the plan filing shall quantify the costs to deploy and operate smart meter technology that is capable of the following minimum requirements set forth in 66 Pa.C.S. § 2807(g):

- Bidirectional data communications.
- Recording usage data on at least an hourly basis once per day.

- Providing customers with direct access to and use of price and consumption information.
- Providing customers with information on their hourly consumption.
- Enabling time-of-use rates and real-time price programs.
- Supporting the automatic control of the customer's electric consumption.

In addition, each plan filing shall include the individual incremental costs for deploying and operating the following smart meter technology capabilities:

- Ability to remotely disconnect and reconnect.
- Ability to provide 15-minute or shorter interval data to customers, EGSs, third-parties and an RTO on a daily basis, consistent with the data availability, transfer and security standards adopted by the RTO.
- On-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as ANSI C12.19 and C12.22 tables.
- Open standards and protocols that comply with nationally recognized non-proprietary standards, such as IEEE 802.15.4.
- Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible.
- Ability to monitor voltage at each meter and report data in a manner that allows an EDC to react to the information.
- Ability to remotely reprogram the meter.
- Ability to communicate outages and restorations.
- Ability to support net metering of customer-generators.

The deployment and operating costs to be presented shall include a breakdown of all incremental costs and any associated potential operational and maintenance cost savings for each functionality and configuration. All cost estimates must be supported by estimates from at least two vendors where available. To the extent that an EDC or another party demonstrates that a particular Commission imposed requirement is not cost-effective, the Commission will have the option of waiving a particular requirement for that EDC or all EDCs. This waiver authority does not extend to the minimum requirements delineated in 66 Pa.C.S. § 2807(g). Any EDC that is unable to provide this cost data with its August 14, 2009 filing can petition the Commission for permission to file such data at a later date. Any such filing shall include a proposed filing date.

Furthermore, the Commission recognizes that consideration of these cost issues may benefit from further discussion prior to the August 14, 2009, filing deadline. In order to facilitate this discussion, the Commission will convene a stakeholder meeting no later than July 17, 2009.

The Commission will allow each EDC to develop a reconcilable adjustment clause tariff mechanism in accordance with 66 Pa.C.S. § 1307 and include this mechanism in its smart meter plan. Such a mechanism shall be designed to recover, on a full and current basis from each customer class, all prudent and reasonable smart meter costs less operating and capital cost savings realized by the EDC from the installation and use of smart meter technology. The mechanism shall be set forth in the EDC's tariff, accompanied by a full and clear explanation as to its operation and applicability to each customer class. The tariff mechanism will be subject to an annual review and reconciliation in accordance with 66 Pa.C.S. § 1307(e). Such annual review and reconciliation will be scheduled to coincide with the submission of the "Smart Meter Progress" annual report outlined in Section B.1 above.

2. Allocation of Costs to Customer Classes

The Commission will require that all measures associated with an EDC's smart metering plan shall be financed by the customer class that receives the benefit of such measures. In order to ensure that proper allocation takes place, it will be necessary for the utilities to determine the total costs related to their smart metering plans, as discussed in E.1. Once these costs have been determined, we will require the EDC to allocate those costs to the classes whom derive benefit from such costs. Any costs that can be clearly shown to benefit solely one specific class should be assigned wholly to that class. Those costs that provide benefit across multiple classes should be allocated among the appropriate classes using reasonable cost of service practices.

OCA stated that it feels traditional rate base procedures would be the preferred method for recovery, rather than an adjustment mechanism that may be unnecessarily complicated. OCA also says that if an adjustment mechanism is used only reasonable net costs should be included in the surcharge. PECO, FirstEnergy, and EA counter by asserting that including the costs in base rates is the best method for cost recovery. PECO asserts that an EDC should use whatever method it sees fit, as the Act allows for recovery through either method, noting its belief that the methods are not mutually exclusive. FirstEnergy states that OCA's claim that base rates are the preferred method of recovery is premature and that EDCs deserve the chance to design and submit a plan for recovery before it is rejected.

A number of commenters agree that care should be taken to ensure the proper allocation of costs amongst customer classes. IECPA recommends that the Commission should allow any customer or customer class that has previously paid to have smart meters installed to be exempt from all costs of the smart meter program. EA strongly objects to that recommendation, saying that a fully functional smart meter involves an entire network and that these comments ignore the costs of upgrading the systems that support smart meters. They go on to note that eliminating an entire class from paying its share of reasonable costs before the submission of a single smart meter plan is premature, ignores the policy underlying Act 129, and undercuts the role of the Commission in reviewing and approving cost recovery mechanisms. Finally, EA, PECO and Duquesne suggested that under-depreciated abandoned assets need to be recovered as stranded costs and that the Commission should allow for accelerated depreciation of assets that are retired early.

The Commission believes the EDCs should install smart meters in a manner that coincides with the full depreciation of existing meters, so as to minimize the stranded costs. However, in the event that there are stranded costs that need to be recovered the Commission agrees with EA, PECO and Duquesne that the EDCs should be allowed to seek recovery of those costs through an accelerated depreciation schedule, to be included in the EDC's cost recovery plan.

The Commission also agrees with FirstEnergy that it is premature to deem one method of recovery preferable to another. The Commission interprets 66 Pa.C.S. § 2807(f)(7) as permitting an EDC to use either method of cost recovery at its discretion.

The Commission disagrees with IECPA's basic premise that a customer or entire customer class should be exempt from all costs associated with these smart meter plans. We agree with the EA that it is premature to suggest such a blanket exemption.

CONCLUSION

This Implementation Order establishes the Commission's smart meter technology procurement and installation standards each EDC with greater than 100,000 customers must meet. This Order also provides guidance on the procedures to be followed for submittal, review and approval of all aspects of each smart meter plan. In addition, it establishes the minimum smart meter capabilities and guidance on deployment of smart meter technology. We extend our thanks to those who participated by providing comments on this important and timely energy program. We would especially like to note our appreciation for the cooperation and courtesy extended by all, which was essential in meeting the aggressive timelines established by the General Assembly for Act 129 implementation. **THEREFORE,**

IT IS ORDERED:

1. That the Commission establishes specific smart meter technology minimum capabilities and procedures for submittal, review and approval of all aspects of each smart meter plan to include cost recovery.

2. That electric distribution companies with greater than 100,000 customers adhere to the guidelines for smart meter technology procurement and installation identified in this Implementation Order.

3. That the Director of Operations convene a stakeholder meeting no later than July 17, 2009, to discuss issues related to the costs and benefits associated with the Commission imposed smart meter capability requirements.

4. That all electric distribution companies that are required to file a smart meter technology procurement and installation plan file such a plan consistent with the directives contained in this order by August 14, 2009.

5. That all electric distribution companies that are required to install smart meter technology are exempt from compliance with 52 Pa. Code § 57.20(h) for testing watthour meters that are being replaced with smart meters in accordance with an approved smart meter technology procurement and installation plan.

6. That all EDCs may recover the reasonable and prudent costs of providing smart meter technology in accordance with the procedures set forth in this Implementation Order.

7. That this Implementation Order be published in the *Pennsylvania Bulletin* and served on the Office of Consumer Advocate, Office of Small Business Advocate, Office of Trial Staff, all jurisdictional electric distribution companies and all parties that filed comments under this docket.

BY THE COMMISSION

James J. McNulty
Secretary

(SEAL)

ORDER ADOPTED: June 18, 2009

ORDER ENTERED: June 24, 2009

PENNSYLVANIA
PUBLIC UTILTY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held June 30, 2011

Commissioners Present:

Robert F. Powelson, Chairman
John F. Coleman, Jr., Vice Chairman, Statement
Tyrone J. Christy
Wayne E. Gardner
James H. Cawley

Petition of West Penn Power Company d/b/a Allegheny Power for Expedited Approval of its Smart Meter Technology Procurement and Installation Plan	: : : :	M-2009-2123951

ORDER

BY THE COMMISSION:

We adopt as our action the Initial Decision on Remand of Administrative Law Judge Mark A. Hoyer, dated May 3, 2011;

THEREFORE,

IT IS ORDERED:

That the unopposed Amended Joint Petition for Settlement of All Issues filed by West Penn Power Company d/b/a Allegheny Power is granted without modification.

BY THE COMMISSION

Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: June 30, 2011

ORDER ENTERED: June 30, 2011

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held June 5, 2014

Commissioners Present:

Robert F. Powelson, Chairman
John F. Coleman, Jr., Vice Chairman
James H. Cawley
Pamela A. Witmer
Gladys M. Brown

Joint Petition of Metropolitan Edison	
Company, Pennsylvania Electric Company,	M-2013-2341990
Pennsylvania Power Company and West Penn	M-2013-2341991
Power Company For Approval of Their	M-2013-2341993
Smart Meter Deployment Plan	M-2013-2341994

OPINION AND ORDER

BY THE COMMISSION:

Before the Pennsylvania Public Utility Commission (Commission) for consideration and disposition is the Revised Smart Meter Deployment Plan (Revised Deployment Plan) 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 or FirstEnergy) filed on March 19, 2014, pursuant to the Commission's March 6, 2014, Opinion and Order (March 6 Order). In accordance with the Commission's Secretarial letter issued on April 16, 2014, Administrative Law Judge (ALJ) Elizabeth H. Barnes certified the record in this proceeding on May 15, 2014. For the reasons stated below, we shall approve the Revised Deployment Plan proposed by FirstEnergy consistent with this Opinion and Order.

I. Background

On October 15, 2008, Act 129 was signed into law and was codified as part of the Public Utility Code (Code), 66 Pa. C.S. § 2806.1, *et seq*. Act 129 became effective on November 14, 2008, and required Electric Distribution Companies (EDCs) with at least 100,000 customers to present a Smart Meter Technology Procurement and Installation Plan (SMP Plan) to the Commission for approval. 66 Pa. C.S. § 2807(f). Specifically, Section 2807(f)(2) directed EDCs to furnish smart meter technology as follows: 1) upon request from a customer that agrees to pay the cost of the smart meter at the time of the request; 2) in new building construction; and 3) in accordance with a depreciation schedule not to exceed fifteen years. 66 Pa. C.S. § 2807(f)(2).

The Commission issued an Order on June 24, 2009, to establish standards and provide guidance for implementing the requirements of Act 129.[1] Pursuant to Section 2807(f) of the Code, 66 Pa. C.S. § 2807(f), Met-Ed, Penelec and Penn Power (collectively, the FirstEnergy Companies) filed their Joint Petition for Approval of Smart Meter Technology Procurement and Installation Plan (2009 SMP) on August 14, 2009. By Order entered on June 9, 2010, the Commission approved the 2009 SMP of the FirstEnergy Companies with modifications. The Commission noted that these Companies expected to file their full Deployment Plan by April 2012.[2]

Also on August 14, 2009, West Penn filed a Smart Meter Implementation Plan (WPP SMP) separately from the three FirstEnergy Companies. During the Commission's review of the WPP SMP, Met-Ed's, Penelec's and Penn Power's ultimate

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[1] *In Re: Smart Meter Procurement and Installation*, Docket No. M-2009-2092655 (Order entered June 24, 2009) *(Implementation Order).*

[2] *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company for Approval of Smart Meter Technology Procurement and Installation Plan*, Docket No. M-2009-2123950 (Order entered June 9, 2010).

corporate parent, FirstEnergy Corp., and West Penn's corporate parent, Allegheny Energy, Inc., announced their intent to merge. As a result, the WPP SMP filing was reassessed. On June 30, 2011, the Commission approved a Joint Petition for Settlement of All Issues (WPP Settlement) regarding the WPP SMP. *Petition of West Penn Power Company for Expedited Approval of its Smart Meter Technology Procurement and Installation Plan*, Docket No. M-2009-2123951 (Order entered March 9, 2011).[3] In the WPP Settlement, West Penn agreed to file its full Deployment Plan as part of its revised WPP SMP with the Commission by June 2012.

II. History of the Proceeding

On May 25, 2012, the Companies requested an extension for the filing of their Smart Meter Deployment Plan to the end of 2012, in order to evaluate new smart meter technologies. The Commission granted that request by Secretarial Letter dated June 28, 2012.

On December 31, 2012, the Companies filed a Joint Petition for approval of their Smart Meter Deployment Plan (Deployment Plan), in which they requested that the Commission: (1) find that their proposed Deployment Plan satisfies the requirements of Act 129 and the Commission's *Implementation Order*; (2) approve the Companies' proposed procurement and deployment of approximately 2.1 million smart meters, over 98% of which should be installed by the end of 2019; (3) authorize the Companies to continue to recover smart meter costs through their previously approved Smart Meter Technologies Charge (SMT-C) Riders, including $5.1 million of costs incurred by West Penn in anticipation of the installation of smart meters; and (4) authorize the Companies

[3] The Commission adopted the Initial Decision of the ALJ and approved the WPP Settlement by Order entered June 30, 2011, at Docket No. M-2009-2123951.

to create a regulatory asset for their investment in their existing meters (Legacy Meters) to be replaced by smart meters.

On February 7, 2013, Petitions to Intervene were filed by Direct Energy Services, LLC (Direct) and collectively on behalf of the Met-Ed Industrial Users Group, the Penelec Industrial Customer Alliance, the Penn Power Users Group, and the West Penn Power Industrial Intervenors (collectively, the Industrial Customer Groups). The following day, the Office of Consumer Advocate (OCA) submitted Comments and an Answer to the Joint Petition. On February 14, 2013, the Office of Small Business Advocate (OSBA) filed a Notice of Intervention.

An evidentiary hearing was held in Harrisburg on May 8, 2013, at which time the Companies' witnesses were presented for oral rejoinder and cross examination and the OCA witness was presented and cross-examined. Also, the Companies and Direct submitted a document entitled "Joint Stipulation of Position," that was admitted as Direct Energy Hearing Exhibit 1, and was intended to resolve certain notification issues raised by Direct. Finally, and by agreement of the Parties, the record was held open to allow the Companies to submit copies of a table that originally appeared in the OCA's surrebuttal testimony, but was later removed and replaced by the OCA at the May 8, 2013 hearing (Joint Petitioners' Cross Examination Exhibit 2). This late exhibit was filed on May 13, 2013. Main Briefs were filed on May 24, 2013, by the Companies and the OCA and Reply Briefs were filed on June 3, 2013, by the same Parties. The record was closed on June 3, 2013.

By Recommended Decision issued on November 8, 2013, ALJ Barnes recommended that the Companies' Petition be adopted as modified and directed the Companies to file an amended Plan within 120 days of the Commission's Order.

Exceptions to the Recommended Decision were filed by the Companies and the OCA on December 2, 2013. Replies to Exceptions were filed by the Companies and the OCA on December 12, 2013.

In our *March 6 Order*, we adopted the Recommended Decision of ALJ Barnes, with modifications. In response to a request by FirstEnergy to accelerate the smart meter deployment schedule in the Penn Power system we directed that:

> …if the Companies feel strongly about implementing this accelerated Penn Power deployment schedule, then they should promptly submit an amended Plan, with proper supporting documentation, with the Commission to properly provide the opportunity for all affected Parties, as well as this Commission, to fully evaluate and comprehend this proposal. If the Companies decide to pursue an accelerated deployment, they must file an amended Plan within thirty days of the entry of this Opinion and Order, stating their case more fully and in more detail. 52 Pa. Code § 5.93(a). Thereafter, the Commission will schedule an expedited procedural schedule so that the amended Plan could be decided within ninety days of the entry of the instant Opinion and Order.

March 6 Order at 43.

Subsequently, on March 19, 2014, the Companies submitted their Revised Deployment Plan, which was filed to serve both as a compliance filing with respect to the *March 6 Order* and as explanation and support for the modification of the Original Deployment Plan filed on December 31, 2012. On March 31, 2014, the OCA filed Exceptions in response to the Revised Deployment Plan filing pursuant to 52 Pa. Code § 5.592. The Companies filed a response to the OCA's Exceptions on April 7, 2014.

On April 16, 2014, the Commission issued a Secretarial Letter wherein the Companies' Revised Deployment Plan was referred to the Office of Administrative Law

Judge for the development of an evidentiary record on an expedited basis in order to permit consideration of this matter at the Public Meeting of June 5, 2014. The Secretarial Letter further directed the presiding officer to establish a procedural schedule that enabled the preparation of an order certifying the record to the Commission on or before May 15, 2014. Additionally, the Secretarial Letter directed the Bureau of Technical Utility Services to review and prepare a public meeting recommendation on the limited scope of compliance with the *March 6 Order*, but not the Revised Deployment Plan. We also considered compliance with the *March 6 Order* during our June 5, 2014, Public Meeting.

As a result, an evidentiary hearing was held on May 7, 2014, at which time the Companies' witnesses were presented for cross examination and the OCA witness was presented and cross-examined. A transcript of this evidentiary hearing was filed on May 8, 2012, consisting of pages 144 through 226.

Main Briefs were filed on May 14, 2012, by FirstEnergy, the Industrial Customer Groups and the OCA.

On May 15, 2014, ALJ Barnes issued an Order Certifying Record to the Commission identifying the documents that comprise the evidentiary record in this proceeding.

III. Discussion

A. Legal Standards

In this proceeding the Companies seek approval of their plan to accelerate the deployment of smart meters and, as such, have the burden of proving that the Petition complies with the applicable legal requirements. Act 129 allows an EDC to recover all reasonable and prudent costs of providing smart meter technology. However, an EDC must provide sufficient support to demonstrate that all such costs are reasonable and prudent with respect to its smart meter plan. *Implementation Order* at 29. In the *Implementation Order*, we concluded that consistent with Section 315(a) of the Code, 66 Pa. C.S. § 315(a), the burden of proof shall be on the EDC. *Id.* Section 315(a) provides, in relevant part:

> Reasonableness of rates.—In any proceeding upon the motion of the [C]ommission, involving any proposed or existing rate of any public utility, or in any proceedings upon complaint involving any proposed increase in rates, the burden of proof to show that the rate involved is just and reasonable shall be upon the public utility.

Id. It is well established that the evidence necessary to meet this burden must be substantial. *Lower Frederick Twp. Water Co. v. Pa. PUC*, 409 A.2d 505, 507 (Pa. Cmwlth. 1980).

Before addressing the Issues, we note that any issue or discussion that we do not specifically delineate shall be deemed to have been duly considered and denied without further discussion. The Commission is not required to consider expressly or at length each contention or argument raised by the parties. *Consolidated Rail Corp. v. Pa. PUC*, 625 A.2d 741 (Pa. Cmwlth. 1993); *also see, generally, University of Pennsylvania v. Pa. PUC*, 485 A.2d 1217 (Pa. Cmwlth. 1984).

B. Revised Smart Meter Deployment Plan

1. Positions of the Parties

a. FirstEnergy

Originally, FirstEnergy proposed a smart meter deployment schedule that contemplated the deployment of 98.5 percent of all smart meters by the end of 2019.

This original deployment schedule contemplated a three-year Solution Validation Stage wherein the Companies would first create a test lab in Penn Power's service territory by installing 60,000 meters before the end of 2016. FirstEnergy M.B. at 4.

According to FirstEnergy, during the period between the submission of briefs in June 2013, and the issuance of the ALJ's Recommended Decision in November 2013, it determined that it could prudently accelerate the smart meter deployment schedule. FirstEnergy states that the Revised Deployment Plan is based upon the most current available information and sets forth a plan that will accelerate the installation of smart meters, with all of Penn Power's 170,000 customers receiving smart meters by the end of 2015 and approximately 98.5 percent of all Pennsylvania FirstEnergy customers receiving smart meters no later than mid-2019. Therefore, deployment of 98.5 percent of all smart meters would be completed six months earlier under the Revised Deployment Plan as compared to the Original Deployment Plan. *Id.* at 4-5.

FirstEnergy explains that the total estimated nominal cost of the Revised Deployment Plan is the same as that included in the Original Deployment Plan, which includes the installation of 110,000 additional meters in Penn Power's service territory by the end of 2015, the completion of much of the smart meter and information technology (IT) infrastructure needed throughout the FirstEnergy Pennsylvania footprint during the shortened Solution Validation Period, and the acceleration of the commencement of the Full-Scale Deployment Phase by one year. However, the Companies will spend approximately $47 million more in capital during the period 2014 through 2019, with a significant portion of this amount occurring in the first three years of deployment and corresponding decreases occurring in later years.[4] As a result of accelerating this spend,

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[4] Met-Ed/Penelec/Penn Power/West Penn Statement No. 4-S (Fitzpatrick Supp.) at 5-6, OCA Statement No. 1-S (Hornby Supp.) at 16; Exh. GLF-3SR; Exh. GLF-4SR. Comparing the two plans, $51 million more capital will be spent through the Revised Deployment Plan in 2014; $49 million more in 2015; $40 million more in 2016; $7 million less in 2017; $28 million less in 2018; and $60 million less in 2019.

FirstEnergy notes that there will be cost shifts among the years, thus impacting both the overall net present value (NPV) of the Revised Deployment Plan and the surcharges to be imposed under Rider SMT-C.[5] According to FirstEnergy, these cost shifts, along with the estimated increase in realized operational cost savings of $12 million were reflected in the modeling of the Revised Deployment Plan. *Id.* at 6-7.

After reflecting the acceleration in spending and the anticipated acceleration of savings in the four cost savings categories identified by the Companies in the Original Deployment Plan, FirstEnergy asserts that the Revised Deployment Plan has a NPV that is $48.1 million more than the Original Deployment Plan when the Companies' Weighted Average Cost of Capital (WACC) is used as the discount rate and no other potential savings are taken into account.[6] However, the Companies explain that the Revised Deployment Plan is $8 million less than the Original Deployment Plan on an NPV basis when the customers' discount rate of 0.37 percent, which represents the average return an individual could earn on a one-year certificate of deposit (CD), is used.[7] Finally, the Companies note that by using a customer discount rate of 2.67 percent, which reflects the current yield on a ten-year U.S. Treasury note, the NPV of the cost of the Revised Deployment Plan is only $13 million more than the NPV of the Original Deployment Plan.[8] However, FirstEnergy asserts that this relatively minor cost differential is completely eliminated if the estimated savings from only one of the many potential benefits categories – the estimated savings from time of use rates offered by Electric Generation Suppliers (EGSs) – is factored into the analysis. FirstEnergy asserts that if this potential savings is factored into the analysis, the NPV of the Revised

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[5] Met-Ed/Penelec/Penn Power/West Penn Statement No. 4-S (Fitzpatrick Supp.) at 4.

[6] Met-Ed/Penelec/Penn Power/West Penn Statement No. 4-S (Fitzpatrick Supp.) at 6, 8.

[7] *Id*. at 6, 8 and 9.

[8] Met-Ed/Penelec/Penn Power/West Penn Statement No. 4-SR (Fitzpatrick Supp. Reb.) at 5, 7.

Deployment Plan is $630,000 less if the 2.67 percent interest rate is used as the discount factor, and $23 million less if the interest rate on the one year CD is used. *Id.* at 7-9.

FirstEnergy explains that the disparity between itself and the OCA regarding the Revised Deployment Plan is their differing views on the discount factor that should be assumed when assessing the two plans on a NPV basis. FirstEnergy asserts that the Revised Deployment Plan can be adopted at little or no additional cost to the customer, assuming the use of a reasonable discount factor that reflects the customer's opportunity cost for the money it otherwise would not spend during the first several years of the deployment schedule. FirstEnergy asserts that the OCA did not perform an independent NPV comparison of the two plans as it adopted all of the Company's assumptions except for one, the discount rate. FirstEnergy criticized the OCA's election to use a nine percent discount factor which was not income tax adjusted, was supposed to be used to assess federal government projects, and reflected a rate for the private sector. According to FirstEnergy, the nine percent discount rate simply does not reflect a residential customer's opportunity cost of the extra amount per month that the customer would pay during the first several years of deployment if the Revised Deployment Plan is implemented. *Id.* at 9-10.

b. Office of Consumer Advocate

The OCA contends that FirstEnergy's proposal to accelerate smart meter deployment will increase the costs of smart meters, as well as the associated rates to ratepayers, for a modest advancement in the actual deployment of smart meters. According to the OCA, the Companies have failed to show that the Revised Deployment Plan is reasonable or that it will provide benefits that justify its increased costs and rates. The OCA argues that the Companies' position, that the Revised Deployment Plan on a NPV basis will be less costly to ratepayers, is based on a fundamentally flawed analysis that uses a discount rate unsupported by economic theory or experience in other jurisdictions. The OCA opines that when an economically justified discount rate is used to analyze the Revised Deployment Plan, the result illustrates that the NPV costs, as well as the rates to ratepayers over the life of the plan, are significantly higher than under the Original Deployment Plan. OCA M.B. at 7.

The OCA submits that while the total amount of expenditures in nominal terms of the two plans may be the same, this comparison of nominal dollars does not measure the impact of the significant acceleration of capital investments under the Revised Deployment Plan relative to the Original Deployment Plan. The OCA states that to measure the impact on both ratepayers and shareholders, a NPV analysis must be conducted as this analysis accounts for the time value of money. While the Companies and the OCA agree as to the need for the NPV analysis, the OCA avers that it does not agree on the discount rate to be applied. According to the OCA, when the NPV analysis is conducted using the Companies' WACC, the Revised Deployment Plan would increase costs by $48.1 Million over the Original Deployment Plan. Furthermore, the OCA asserts that, while the costs to customers will increase on a NPV basis under the Companies' analysis, it is important to note that shareholders will have higher NPV earnings under the Revised Deployment Plan due to the $47 million increase in capital investment though the year 2019. *Id.* at 11-12.

Next, the OCA contends that the Companies' use of a 0.37 percent discount rate, which is based on the rate of a one-year CD, is improper for two reasons. First, the OCA claims that this rate is without foundation as the Companies admitted that they performed no analysis or customer surveys to arrive at this rate. Second, the OCA states that the Companies ignored the impact of the Revised Plan on ratepayers through 2019, when most of the accelerated spending and cost recovery will occur. According to the OCA, even if the 0.37 percent discount rate is used, the NPV cost to ratepayers through 2019 is 6.6 percent higher under the Revised Deployment Plan than under the Original Deployment Plan. *Id.* at 13-14.

The OCA then notes that the Companies, in Supplemental Rebuttal Testimony, recognized the issues with using the 0.37 percent discount rate and proposed using a 2.67 percent discount rate, which was based on the interest rate for the current ten-year U.S. Treasury note. While the OCA states that it does not agree with the use of the 2.67 percent discount rate, ratepayers would experience a significantly higher ($13 million) overall NPV cost for the Revised Deployment Plan based on this rate. As a result, the OCA opines that the Companies' analyses of the revised Deployment Plan do not support their position that ratepayers will be better off under the Revised Deployment Plan. According to the OCA, the Companies' analyses demonstrate that on a NPV basis, the Revised Deployment Plan will increase costs to ratepayers in both the short term and the long term. *Id.* at 14-15.

The OCA avers that based on its analysis of the Company's Revised Deployment Plan, it is proper to use the Companies' model and a discount rate of nine percent. The OCA maintains that a nine percent discount rate is consistent with the weighted average cost of capital of between 8.17 to 11.29 percent that the Companies used to prepare NPV analyses from their perspective. Further, the OCA asserts that the nine percent discount rate is within the range of discount rates used to analyze smart meter deployment plans across the country. The OCA referred to its Cross-Examination Exhibit 2, which provided the assumptions used in the discount rate calculations for the smart grid project cost-benefit analysis for eight other companies, including West Penn's original smart meter deployment plan at Docket No. M-2009-2123951, prior to its merger with the FirstEnergy Companies. The discount rates from the referenced OCA exhibit range from 6.69 per cent to 8.954 per cent.

The OCA submits that the discount rates used for these other companies show the reasonableness of its use of a nine percent discount rate. According to the OCA, when a nine percent discount rate is used, the NPV cost of the Revised Deployment Plan is twelve percent higher through 2019 than the Original Deployment

Plan, and the NPV net cost of the Revised Deployment Plan through 2032 is 7.6 percent higher. *Id.* at 16-18.

Lastly, the OCA states that the NPV analyses conducted in this proceeding quantifies the future costs and benefits of the Revised Deployment Plan and that these costs and benefits are inputs into the revenue requirements that are the basis of the rates charged to customers. The OCA notes that on a NPV basis, ratepayers would pay eighteen percent more in revenue requirements from 2013 to 2032 and forty-six percent more in revenue requirements from 2013 to 2019, while the Companies' shareholders will have higher NPV aggregate earnings under the Revised Deployment Plan. The OCA opines that the increased rates charged to ratepayers through the SMT-C riders for the rather minor level of accelerated smart meter deployment proposed by the Companies are not reasonable. The OCA points out that for residential customers, SMT-C rates will be higher by amounts ranging from $0.95 per month to $3.39 per month. However, according to the OCA, the Revised Deployment Plan will only accelerate the deployment of smart meters to all customers by six months to the middle of 2019 as compared to the end of 2019 under the Original Deployment Plan. As a result, the OCA's position is that the Commission should reject the Companies' Revised Deployment Plan and direct the Companies to proceed with the Original Deployment Plan as already approved by the Commission in the *March 6 Order*. *Id.* at 18-24.

c. Industrial Customer Groups

The Industrial Customer Groups state that the Companies' Revised Deployment Plan is just and reasonable, and as such should be approved by the Commission. The Industrial Customer Groups allege that the Revised Deployment Plan advances the goals of Act 129 by ensuring that customers will be charged based on their individual meter data at an earlier time than under the Companies' Original Deployment Plan. Additionally, the Industrial Customer Groups aver that an expedited deployment of smart meters will reduce the use of estimated meter data, which will, in turn, reduce a number of customer charges such as unaccounted-for-energy costs. The Industrial Customer Groups note that customers may reduce their costs further by altering their usage behavior after the expedited deployment of smart meters. According to the Industrial Customer Groups, as the Revised Deployment Plan is an improvement to the Companies' Original Deployment Plan, they recommend its adoption. Industrial Customer Groups M.B. at 3-6.

2. Disposition

Based upon our review of the evidence of record, we conclude that FirstEnergy has met its burden of proof to establish that its Revised Deployment Plan is reasonable and in the best interest of its customers. While the Parties provided disparate positions on the appropriate NPV analysis, we note that the use of a higher discount rate based on corporate costs of capital results in a higher cost for the Plan, since the benefits of the plan are discounted more heavily. On the other hand, the use of a lower discount rate, based on money market or U.S. Treasury bond returns, results in a lower cost for the Plan, since the long term benefits of smart meters are discounted less. While well intentioned Parties can all agree to disagree about appropriate discount rates, what is clear in this case, as provided by the Companies, is that only a fraction of the benefits of this revised Plan have been captured in this analysis.

First, this analysis does not factor in other non-operating cost savings that customers may receive sooner through the Revised Deployment Plan. The non-operating cost savings benefits are those that may benefit customers, but may not necessarily reduce an electric distribution company's operating costs. Examples of these types of potential sources of benefits are listed in an October 2013 report entitled "Smart Grid Economic and Environmental Benefits – A Review and Synthesis of Research on Smart Grid Benefits and Costs" ("Report"), prepared by the Smart Grid Consumer

Collaborative ("SGCC"), which studied fifteen utilities' smart meter/smart grid projects that were partially funded through the U.S. Smart Grid Investment Grant program funds. The Report lists as potential sources of non-operating cost savings the following: (1) Integrated Volt/Var Control; (2) Remote Meter Reading, which is incorporated into the Companies' savings analysis; (3) Time Varying Rates; (4) Prepayment and Remote Disconnect; (5) Revenue Assurance; (6) Customer Energy Management; (7) Service Outage Management; (8) Fault Location and Isolation; and (9) Renewable Generation Integration.

Similarly, the Industrial Customer Groups identified other non-operating cost savings by averring that an expedited deployment of smart meters will reduce the use of estimated meter data, which will, in turn, reduce a number of customer charges such as unaccounted-for-energy costs. The Industrial Customer Groups note that customers may reduce their costs further by altering their usage behavior after the expedited deployment of smart meters. Indeed, these were some of the benefits we identified in approving the recent rulemaking Amending Regulations Regarding Standards for Changing a Customer's Electricity Generation Supplier. *Rulemaking to Amend the Provisions of 52 Pa. Code, Chapter 57 Regulations Regarding Standards For Changing a Customer's Electricity Generation Supplier*, Docket No. L-2014-2409383 (Order entered April 3, 2014).

Second, not all potential operating cost savings for the Companies were included in this analysis. The Companies only quantified four cost savings categories that they believed were measureable, verifiable and would allow the Companies to realize actual cash savings through the deployment of smart meters: (1) Meter Reading; (2) Meter Services; (3) Back Office; and (4) Contact Center. Each of these savings categories can be measured through metrics known today. Other categories were also analyzed for inclusion, but were ultimately not selected because they could not meet the parameters described, according to the Companies.

The OCA suggested in its testimony that the Companies should have looked for potential cost savings in other areas including: (1) revenue protection; (2) improved cash flow; (3) avoided capital costs; and (4) future purchases of traditional meters. Each of these areas was reviewed by the Companies. However, the Companies asserted that valid estimates of realizable savings in these areas cannot be made at this time. While there may be potential savings in these or other areas, given the Companies' proposed meter deployment schedule, it may take years to determine if, in fact, the Companies will realize any savings in these areas and, if so, the amount of that savings. Until the meters are installed and data can be studied, it may be difficult to more accurately access these savings. That said, we find it compelling that, in addition to the savings clearly identified by the Companies in their plan, there is the potential for additional operating cost savings in a number of areas.

Third, this Commission has already observed the benefits of early deployment. We find that the use of Penn Power as a case study may help the Companies identify other more cost effective meter deployment strategies that can then be leveraged by FirstEnergy's other operating companies. If deployment and operational savings prove very positive, FirstEnergy may also be in a position to further accelerate smart meter deployment, thus enabling an option to enhance customer savings even more.

And finally, it should also be noted that Act 129 uses the language "not to exceed 15 years." An EDC is encouraged to expedite the deployment process if it will provide increased customer benefits in a cost-effective manner. Again, the primary goal of the EDC deployment plan should be to implement a deployment and installation schedule that best balances the overall efficiency and timeliness of the smart meter installations with the costs incurred. Given the clear advantages that accelerated smart meter deployment will provide to both the Companies and their customers, we shall approve FirstEnergy's Plan as submitted.

Accordingly, we shall direct FirstEnergy to implement its Revised Deployment Plan and not pursue their Original Deployment Plan.

IV. Conclusion

For the reasons set forth above, we shall approve the Revised Smart Meter Deployment Plan submitted by FirstEnergy, consistent with this Opinion and Order. FirstEnergy is directed to implement its Revised Deployment Plan, subject to any modifications contained in our companion Compliance Order adopted today at this docket; **THEREFORE,**

IT IS ORDERED:

1. That the Revised Smart Meter Deployment Plan submitted on March 19, 2014, by Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company is approved.

2. That Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company be required to fully investigate and track all sources of potential savings, including, but not limited to, theft reduction, revenue enhancement, avoided capital costs and distribution operations, and flow-through these savings to their customers in future SMT-C rider filings.

3. That the Smart Meter Deployment Plan as proposed by the 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 filed on December 31, 2012, in the above-captioned matter is adopted as modified by this Opinion and Order and as may be modified by the companion Compliance Order adopted June 5, 2014, at this docket.

BY THE COMMISSION,

Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: June 5, 2014

ORDER ENTERED: June 25, 2014