

1001 G Street, N.W.
Suite 500 West
Washington, D.C. 20001
tel. 202.434.4100
fax 202.434.4646

Writer's Direct Access
Timothy A. Doughty
(202) 434-4271
doughty@khlaw.com

January 20, 2020

Via ECFS

Marlene J. Dortch, Secretary
Federal Communications Commission
Office of the Secretary
445 12th Street SW
Washington, DC 20554

**Re: Metropolitan Edison Company, Pennsylvania Electric Company, and
Penn Power Company's Responses to Complainants' First Set of
Interrogatories (Proceeding Number 19-354; Bureau ID Number EB-19-
MD-008)**

Ms. Dortch:

Please find attached Metropolitan Edison Company, Pennsylvania Electric Company, and
Penn Power Company's Responses to the Complainants' First Set of Interrogatories in
Proceeding Number 19-354; Bureau ID Number EB-19-MD-008.

Sincerely,



Timothy A. Doughty
Attorney for Metropolitan Edison Company,
Pennsylvania Electric Company, and Penn Power
Company

Enclosures

cc: Rosemary McEnery, Enforcement Bureau
Anthony DeLaurentis, Enforcement Bureau

Before the
FEDERAL COMMUNICATIONS COMMISSION
Washington, D.C. 20554

_____)	
)	
Verizon Pennsylvania LLC and)	
Verizon North LLC,)	
)	
<i>Complainants,</i>)	
)	Proceeding Number 19-354
)	
v.)	Bureau ID Number EB-19-MD-008
)	
Metropolitan Edison Company,)	
Pennsylvania Electric Company, and)	
Penn Power Company,)	
)	
<i>Defendants</i>)	
_____)	

**METROPOLITAN EDISON COMPANY, PENNSYLVANIA ELECTRIC COMPANY,
AND PENN POWER COMPANY’S RESPONSES
TO COMPLAINANT’S FIRST SET OF INTERROGATORIES**

Defendants Metropolitan Edison Company (“Met-Ed”), Pennsylvania Electric Company (“Penelec”), and Pennsylvania Power Company (“Penn Power”) (collectively, “FirstEnergy”), pursuant to Section 1.730 of the Commission’s Rules, 47 C.F.R. §1.730, submit the following Responses to the First Set of Interrogatories of Complainants Verizon Pennsylvania LLC and Verizon North LLC (“Verizon”) to FirstEnergy.

INTERROGATORIES

INTERROGATORY NO. 1:

Beginning with the 2011 rental year, state the annual pole attachment rental rates that FirstEnergy contends are “just and reasonable” for Verizon’s use of FirstEnergy’s poles under 47 U.S.C. § 224(b). Include in your response all facts on which you rely for your contention that the annual pole attachment rental rates are “just and reasonable” under 47 U.S.C. § 224(b), the formula, calculations, inputs, assumptions, and source data used to calculate each annual pole attachment rental rate, and the corresponding pole attachment rental rate that would apply to FirstEnergy’s use of Verizon’s poles.

RESPONSE: Consistent with and without waiving FirstEnergy’s objections, and as will be further explained in FirstEnergy’s Answer, the annual pole attachment rental rates that FirstEnergy contends are “just and reasonable” for Verizon’s use of Penelec’s and Penn Power’s poles under 47 U.S.C. § 224(b) are those specified in the joint use agreements and amendments Verizon entered into with Penelec and Penn Power. Met-Ed does not charge a pole attachment rental rate to Verizon but instead the agreements require a deficiency payment to be made. That deficiency payment is calculated pursuant to the joint use agreements and amendments Verizon entered into with Met-Ed, and is “just and reasonable” consistent with 47 U.S.C. § 224(b).

INTERROGATORY NO. 2:

Explain in detail what, if any, steps FirstEnergy has taken to ensure that its Joint Use Agreements and License Agreements comply with the “just and reasonable” rate provision of 47 U.S.C. § 224(b), the Pole Attachment Order, the Verizon Florida decision, the Verizon Virginia decision, and the rate section of the Third Report and Order (Section III.C).

RESPONSE: Consistent with and without waiving FirstEnergy's objections, and as will be further explained in FirstEnergy's Answer, the parties negotiated Agreements with rate and payment provisions that are just and reasonable under the Pole Attachment Act and Commission rulings. Verizon participated in those negotiations.

INTERROGATORY NO. 3:

Beginning with the 2011 rental year, identify all entities that have had a Joint Use Agreement or License Agreement with FirstEnergy and state whether the entity is an incumbent local exchange carrier, CLEC, cable company, wireless provider, or other entity.

RESPONSE: Consistent with and without waiving FirstEnergy's objections, FirstEnergy cannot respond to any part of this Interrogatory until the parties sign a non-disclosure agreement and without further guidance from the Commission.

INTERROGATORY NO. 4:

Beginning with the 2011 rental year, state the annual pole attachment rental rate that FirstEnergy charged each entity identified in response to Interrogatory 3, the number of poles or attachments for which the pole attachment rental rate was charged, and whether the entity uses FirstEnergy's poles pursuant to a License Agreement or a Joint Use Agreement. Include in your response the formula, calculations, inputs, assumptions, and source data used to calculate each pole attachment rental rate charged and state whether the rate was charged on a per-pole, per-attachment, or other basis and whether the rate was paid.

RESPONSE: Consistent with and without waiving FirstEnergy's objections, FirstEnergy cannot respond to any part of this Interrogatory until the parties sign a non-disclosure agreement and without further guidance from the Commission.

INTERROGATORY NO. 5:

State the rates, terms, and conditions of all Joint Use Agreements and License Agreements with FirstEnergy that were in effect at any time from the 2011 rental year forward. Include in your response the name of the entity that is a party to the Joint Use Agreement or License Agreement with FirstEnergy and the dates on which the Joint Use Agreement or License Agreement with FirstEnergy was in effect. In lieu of stating the rates, terms, and conditions of all Joint Use Agreements and License Agreements, FirstEnergy may produce copies of each such Joint Use Agreement and License Agreement.

RESPONSE: Consistent with and without waiving FirstEnergy's objections, FirstEnergy cannot respond to any part of this Interrogatory until the parties sign a non-disclosure agreement and without further guidance from the Commission.

INTERROGATORY NO. 6:

With respect to each License Agreement identified in response to Interrogatory 5, identify any advantage or benefit that FirstEnergy contends Verizon receives under any JUA, and any disadvantage imposed on Verizon under any JUA, as compared to the terms and conditions provided to the attaching entity. Include in your response, beginning with the 2011 rental year, a quantification of the annual monetary value of each such claimed advantage, benefit, or disadvantage expressed on a per-pole basis, the JUA to which the claimed advantage, benefit, or disadvantage applies, the language from each License Agreement that establishes or supports the claimed advantage, benefit, or disadvantage, and all data, formulas, calculations, inputs, assumptions, and source data used to quantify the monetary value of each claimed advantage, benefit, or disadvantage.

RESPONSE: Consistent with and without waiving FirstEnergy's objections, FirstEnergy will respond to this Interrogatory when FirstEnergy files its Answer to the Complaint.

INTERROGATORY NO. 7:

With respect to each “Verizon Competitive Advantage” listed in the bullet-point list in David J. Karafa’s email to Brian H. Trosper, dated June 7, 2018 (a copy of which email is included as Exhibit 29 to the Pole Attachment Complaint), state all facts that supported Mr. Karafa’s characterization of each bullet-pointed item as a “Verizon Competitive Advantage.” Include in your response all data, analyses, formulas, calculations, inputs, or assumptions used to quantify each “Verizon Competitive Advantage.”

RESPONSE: Consistent with and without waiving FirstEnergy’s objections, FirstEnergy will respond to this Interrogatory when FirstEnergy files its Answer to the Complaint.

INTERROGATORY NO. 8:

Beginning with the 2011 rental year, for each claimed advantage or benefit identified in response to Interrogatory 6 and for each “Verizon Competitive Advantage” identified in Interrogatory 7, state by year the amount of money that FirstEnergy collected from each entity identified in response to Interrogatory 3 concerning that claimed advantage, benefit, or “Verizon Competitive Advantage,” and the number of poles for which the amounts were charged and collected. Include in your response all formulas, calculations, inputs, assumptions, and source data used to invoice these amounts.

RESPONSE: Consistent with and without waiving FirstEnergy’s objections, FirstEnergy will respond to this Interrogatory when FirstEnergy files its Answer to the Complaint.

INTERROGATORY NO. 9:

Beginning with the 2011 rental year, state the rate of return used by FirstEnergy in the calculation of rates under 47 C.F.R. § 1.1406(d), including the cost of debt, cost of equity, and capital structure, and, if different, FirstEnergy’s state-authorized weighted average cost of capital and/or

weighted cost of equity, including, as appropriate, the cost of debt, cost of equity, and capital structure. Include in your response the formula, calculations, inputs, assumptions, and source data used.

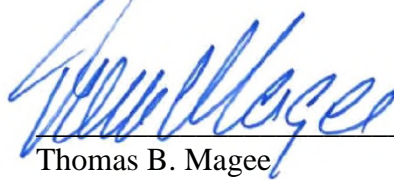
RESPONSE: Without waiving FirstEnergy's objections, when FirstEnergy calculates rates for Met-Ed, Penelec and Penn Power pursuant to 47 C.F.R. § 1.1406(d), FirstEnergy uses the rate of return approved in the respective utility's last rate case, as instructed by Commission rules. The Pennsylvania Public Utility Commission ("PaPUC") order approving those rates of return for Met-Ed and Penelec is attached hereto at Exhibit A (see page 137). The PaPUC order approving that rate of return for Penn Power is attached hereto at Exhibit B (see page *216).

INTERROGATORY NO. 10:

Identify all data regarding poles jointly used by Verizon and FirstEnergy, including all survey, audit or sampling data, concerning pole height, the average number of attaching entities, the space occupied by Verizon, FirstEnergy, and any other entity. Include in your response when the data was compiled or collected, the entity or entities that compiled or collected it, the accuracy requirements, if any, imposed or related to the compilation or collection of the data, and the rules, parameters, and guidelines upon which the data was collected.

RESPONSE: Consistent with and without waiving FirstEnergy's objections, FirstEnergy maintains a database containing information about poles jointly used by Verizon and FirstEnergy, and FirstEnergy is conducting a statistically reliable survey of poles jointly used by Verizon and FirstEnergy. When complete, results of that survey will be provided as part of FirstEnergy's Answer to the Complaint.

Respectfully submitted,



Thomas B. Magee
Timothy A. Doughty
Keller and Heckman LLP
1001 G Street NW
Suite 500 West
Washington, DC 20001
(202) 434-4100 (phone)
(202) 434-4646 (fax)
magee@khlaw.com
doughty@khlaw.com

*Attorneys for Metropolitan Edison Company,
Pennsylvania Electric Company, and Pennsylvania
Power Company*

January 20, 2020

EXHIBIT A

**PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265**

Public Meeting held January 11, 2007

Commissioners Present:

Wendell F. Holland, Chairman
James H. Cawley, Vice Chairman, Concurring & Dissenting Statement attached
Kim Pizzingrilli
Terrance J. Fitzpatrick

Pennsylvania Public Utility Commission,	:	R-00061366
Met-Ed Industrial Energy Users Group and	:	
Industrial Energy Consumers of Pennsylvania,	:	R-00061366C0001
William R. Lloyd, Jr., Small Business Advocate,	:	R-00061366C0002
Irwin A. Popowsky, Consumer Advocate,	:	R-00061366C0003
Met-Ed Industrial Energy Users Group and	:	
Industrial Energy Consumers of Pennsylvania,	:	R-00061366C0005
R.H. Sheppard Co., Inc.	:	R-00061366C0013

v.

Metropolitan Edison Company

Pennsylvania Public Utility Commission,	:	R-00061367
Penelec Industrial Customer Alliance and	:	
Industrial Energy Consumers of Pennsylvania,	:	R-00061367C0001
William R. Lloyd, Jr., Small Business Advocate,	:	R-00061367C0002
Irwin A. Popowsky, Consumer Advocate,	:	R-00061367C0003
Penelec Industrial Customer Alliance and	:	
Industrial Energy Consumers of Pennsylvania,	:	R-00061367C0005
Pierre Fortis,	:	R-00061367C0007
L.C. Rhodes	:	R-00061367C0008

v.

Pennsylvania Electric Company

Petition of Metropolitan Edison Company for	:	
Approval of a Rate Transition Plan	:	P-00062213
Petition of Pennsylvania Electric Company for	:	
Approval of a Rate Transition Plan	:	P-00062214
Re: Merger Savings Remand Proceeding	:	A-110300F0095
	:	A-110400F0040

TABLE OF CONTENTS

I.	HISTORY OF THE PROCEEDINGS	2
II.	MERGER SAVINGS	10
A.	Allocation of Merger Savings	10
B.	Amount of Merger Savings	16
III.	NON-NUG STRANDED COST RECOVERY/NUG COST RECOVERY	17
A.	Non-NUG Stranded Cost Recovery	17
B.	Non-stranded NUG Costs.....	22
IV.	GENERATION RATE CAP	28
V.	TRANSMISSION SERVICE CHARGE RIDER	50
A.	Inclusion of Congestion Costs in the TSC Rider	51
B.	Deferred 2006 Transmission Charges	58
VI.	GENERAL PRINCIPLES FOR A 1308 GENERAL RATE INCREASE CASE.....	65
VII.	RATE BASE/CASH WORKING CAPITAL	68
A.	Distribution.....	68
1.	Pennsylvania Corporate Net Income Tax and Pennsylvania Capital Stock Tax	69
2.	Treatment of “Non-Cash” Items	72
3.	Treatment of Transmission Costs	76
4.	Treatment of Return on Equity and Payment Lag Associated with Interest on Long-Term Debt.....	79
5.	Payment Lag Associated with Certain “Other O&M” Items.....	81
VIII.	REVENUES AND EXPENSES	83
A.	Universal Service Charge Deferral Recovery Period and Imposition of Carrying Charges	83
B.	Payroll Expense	86
C.	Pension Expense	87
D.	Other Post Employment Benefits (OPEB)	93
E.	Rate Case Expense.....	94

F.	Consolidated Tax Savings	97
G.	Investment Tax Credits and Excess Deferred Income Taxes	103
H.	Decommissioning Costs	104
I.	Community Action Association of Pennsylvania (CAAP) Claim	108
J.	Conservation and Renewable Initiatives: Retention of Riders and PennFuture Initiatives	110
1.	Sustainable Energy Fund Riders	110
2.	Penn Future’s Renewable Energy Initiatives	114
IX.	RATE OF RETURN.....	117
A.	Capital Structure	117
B.	Cost of Capital	120
C.	Return on Equity.....	126
X.	COST OF SERVICE	137
A.	ALJs’ Interpretation of <i>Lloyd v. Pa. PUC</i> , 904 A.2d 1010 (Pa. Cmwlth. 2006), Petitions for Allowance of Appeal Pending	137
XI.	RATE DESIGN	145
A.	Metropolitan Edison Company - Unopposed Rate Design Changes	145
B.	Pennsylvania Electric Company - Unopposed Rate Design Changes.....	146
C.	Disputed Rate Design Issues	147
1.	Rates RS and RT	147
2.	Rates GS and GST	151
3.	Eight Hour on-Peak Time of Day Option (ME)	153
4.	Rates GP and LP	154
XII.	TARIFF PROVISIONS.....	154
A.	Metropolitan Edison Company Unopposed Tariff Changes	154
B.	Pennsylvania Electric Company Unopposed Tariff Changes	157
C.	Resolved Tariff Issues	158
1.	Rule 15d – Exit Fees	158
2.	Limitation of Liability.....	159
3.	Business Development Riders (BDRs).....	159
4.	Rule 12b(9) Transformer Losses Adjustment.....	160

D.	Disputed Tariff Issues.....	161
1.	Real Time Pricing (RTP) Rate	161
E.	Wind Product	165
F.	Hourly Pricing	166
G.	Seasonal Time of Day Provisions (Met-Ed).....	169
H.	Elkland Rates	171
XIII.	SECTION 1307 RIDERS.....	175
A.	Storm Damage Rider	175
B.	Universal Service Cost Rider	177
C.	Government Mandated Programs Rider	182
XIV.	DIRECTED QUESTIONS OF VICE CHAIRMAN CAWLEY	185
XV.	MISCELLANEOUS.....	185
XVI.	CONCLUSION.....	188
	TABLES	1
	APPENDIX A.....	1

OPINION AND ORDER

BY THE COMMISSION:

Before the Commission for consideration and disposition is the Recommended Decision of Administrative Law Judges (ALJs) Wayne L. Weismandel and David A. Salapa, issued November 2, 2006, in the above captioned consolidated proceedings involving the Merger Savings Remand of GPU, Inc. (GPU) and FirstEnergy Corp. (FirstEnergy), as well as the General Rate Increase and the Rate Transition Plan proposals of Metropolitan Edison Company (ME) and Pennsylvania Electric Company (PE) (collectively, the Companies or MEPN). Also before the Commission are the Exceptions and Reply Exceptions filed thereto.

Exceptions to the Recommended Decision were filed by the Office of Trial Staff (OTS) on November 21, 2006. The following Parties filed Exceptions on November 22, 2006: the Companies, Citizen Power, the Office of Small Business Advocate (OSBA), the Office of Consumer Advocate (OCA), Constellation New Energy, Inc. and Constellation Energy Commodities Group (collectively, Constellation), Met-Ed Industrial User Group (MEIUG) and Penelec Industrial Customer Alliance (PICA), PennFuture, and the Berks County Community Foundation and the Community Foundation for the Alleghenies (collectively, the SEFs).

The following Parties filed Reply Exceptions on December 4, 2006: the Companies, Citizen Power, OSBA, OCA, OTS, Constellation, the Commercial Group, MEIUG and PICA, PPL Electric Utilities Corporation (PPL) and R.H. Sheppard Co., Inc. (Sheppard).

I. HISTORY OF THE PROCEEDINGS

In *ARIPPA v. Pa. PUC*, 792 A.2d 636 (Pa. Cmwlth., 2002) *alloc. denied*, 572 Pa. 736, 815 A.2d 634 (2003) (*ARIPPA*), the Pennsylvania Commonwealth Court, among other things, remanded to the Commission the issues of determining the amount of and the allocation of merger savings arising from the merger of GPU and FirstEnergy. MEPN were, prior to the merger, regulated public utility subsidiaries of GPU and are now regulated public utility subsidiaries of FirstEnergy. The remanded issues remained docketed at Commission Docket Nos. A-110300F0095 and A-110400F0040, and were subsequently referred to as the Merger Savings Remand Proceeding.

By way of a Secretarial Letter dated April 2, 2003, the Commission thereafter acknowledged that “[o]n January 16, 2003, the Pennsylvania Supreme Court denied or quashed all pending applications for appeal from” *ARIPPA*. Additionally, the Commission therein directed, among other things:

1. The matter of the economic savings resulting from the merger of GPU Corp. and FirstEnergy Corp. at Docket Nos. A-110300F0095 and A-110400F0040 is remanded to the Office of Administrative Law Judge for hearings on the amount and allocation of the merger savings.

By Implementation Order adopted and entered October 2, 2003, at Docket Nos. A-110300F0095, A-110400F0040, P-00001860, and P-00001861, the Commission reaffirmed this portion of the Secretarial Letter dated April 2, 2003.¹

During the balance of calendar year 2003, and continuing through 2005, the Parties to the Merger Savings Remand Proceeding engaged in negotiations to attempt to

¹ A complete history of the post-*ARIPPA* 1 proceedings is contained in the Implementation Order adopted and entered October 2, 2003.

reach a settlement and provided periodic reports to the presiding officer, Administrative Law Judge (ALJ), Larry Gesoff.

On April 10, 2006, ME filed with the Commission Tariff - Electric Pa. P.U.C. No. 49, Docket No. R-00061366. On that same date, PN filed Tariff – Electric Pa. P.U.C. No. 78, Docket No. R-00061367. Each company also filed Petitions for Approval of a Rate Transition Plan; ME at Docket No. P-00062213 and PN at Docket No. P-00062214. The proposed Tariffs were to be effective June 10, 2006. ME’s proposed Tariff contained changes calculated to produce additional revenues of 19 to 24 percent for 2007 and changes in its generation rates for 2008, 2009 and 2010, which could increase rates by up to \$165 million each year. PN’s proposed Tariff contained changes calculated to produce additional revenues of 15 to 19 percent for 2007 and changes in its generation rates for 2008, 2009 and 2010, which could increase rates by up to \$135 million each year. The Petitions for Approval of a Rate Transition Plan for each company proposed new generation rates that would exceed the rate caps established pursuant to the Companies’ restructuring proceedings required under the Electricity Generation Customer Choice and Competition Act, 66 Pa. C.S. § 2801 *et seq.* (Competition Act), and the Joint Petition for Full Settlement of the Restructuring Plans of MEPN and Related Dockets and Related Proceedings (Restructuring Settlement) approved by Commission Final Opinion and Order, entered October 20, 1998, at Docket Nos. R-00974008, R-00974009, P-00971215, P-00971216, P-00971217, P-00971223, P-00971278, P-00981324, P-00981325 and P-00900450. The Companies also filed a Motion to Consolidate the Merger Savings Remand Proceeding, Docket Nos. A-110300F0095 and A-110400F0040, with the rate cases and transition plan cases.

On May 4, 2006, the Commission adopted and entered an Order which consolidated the Merger Savings Remand Proceeding with the two rate cases and the two transition plan cases, suspended the filings until January 10, 2007, and ordered an

investigation and hearings by the Office of Administrative Law Judge (OALJ). The consolidated case was assigned to the presiding ALJs.

The following entities and individuals filed Formal Complaints against the Companies' proposed rate increase: MEIUG and the Industrial Energy Consumers of Pennsylvania (IECPA); PICA and IECPA; OSBA; OCA; Pennsylvania Rural Electric Association and Allegheny Electric Cooperative, Inc. (PREA/AEC); Central Bradford Progress Authority; Robert H. Tansor; L.C. Rhodes; Stan Alekna; G. Thomas Smeltzer; Pierre Fortis; Michael R. Wright; Benjamin Moyer; Carmine Lisante; Berks County Center for Independent Living d/b/a Abilities In Motion (Abilities In Motion); and Sheppard. All of the Complaints filed against the proposed rate increase were satisfied or withdrawn except for those filed by the following Parties: MEIUG and IECPA; OSBA; OCA; Sheppard; PICA and IECPA; Pierre Fortis; and L.C. Rhodes. OSBA also filed formal Complaints against the transition plan filings of MEPN, and the OTS entered its Notice of Appearance on April 18, 2006.

The following entities filed Petitions to Intervene in the consolidated cases which were granted: the Utility Workers Union of America Local 180 and the International Brotherhood of Electrical Workers Local 459 (collectively, the Unions); ARIPPA²; the SEFs; Constellation; York County Solid Waste and Refuse Authority (YCSWA); Retail Energy Supply Association (RESA); PPL Electric Utilities Corporation (PPL); Citizen Power; the Commercial Group; the Community Action Association of Pennsylvania (CAAP); PREA/AEC; and the National Energy Marketers Association (NEMA). The Companies objected to the Petitions to Intervene filed by Citizen Power, PREA/AEC, PPL, and NEMA.

² ARIPPA is a trade association composed of 14 non-utility generation power plants operating across Pennsylvania, all of which use waste coal as a source of fuel. Seven of the members of ARIPPA have long-term contracts to sell power to the Companies.

The following entities withdrew³ from participating in the consolidated proceeding: the Unions; NEMA; PREA/AEC; and Morgan Stanley Capital Group, Inc. (MSCG).

By Accounting Order in *Petition of Metropolitan Edison Company and Pennsylvania Electric Company for Authority to Modify Certain Accounting Procedures*, Docket No. P-00052143, adopted May 4, 2006, entered May 5, 2006, the Commission granted Petitions to Intervene filed in that case by MEIUG, PICA, and PREA/AEC, authorized the Companies to defer for accounting and financial reporting purposes certain incremental FERC-approved transmission charges, and preserved the ability of any party to a rate case to seek or oppose rate recovery of any of the deferred costs. In the Accounting Order, the Commission expressly stated that the Companies would be allowed an opportunity to “seek rate recovery of these incremental transmission expenses in the pending rate cases.”

On May 16, 2006, OCA, OTS, MEIUG/PICA and IECPA, and PennFuture filed a Joint Petition For Clarification, Or Reconsideration Of Consolidation Order And For Establishment Of A Public Meeting Date, contending that the schedule established at the Initial Prehearing Conference in the consolidated case, while designed to accommodate the statutory time requirement for completion of a general rate increase case as well as the Commission’s published schedule for Public Meetings prior to the suspension date of January 10, 2007, was not sufficient for the litigation of the consolidated case. Additionally, the ALJs issued a Protective Order, as submitted by the Parties, to apply to litigation of the consolidated case.

³ Eighteen Parties remained involved in the consolidated case: the Companies, OTS, OCA, OSBA, MEIUG/PICA and IECPA, PPL, the SEFs, RESA, PennFuture, Constellation, Citizen Power, Sheppard, CAAP, ARIPPA, YCSWA, and the Commercial Group.

By Order adopted and entered May 19, 2006, the Commission granted in part the Joint Petition For Clarification, Or Reconsideration Of Consolidation Order And For Establishment Of A Public Meeting Date, ordering the Companies to inform the Commission's Secretary, no later than May 22, 2006, if they would voluntarily extend the effective dates of their proposed tariffs in these proceedings to January 12, 2007, and, if so, a Public Meeting would be scheduled for January 11, 2007, for the purpose of deciding these consolidated proceedings. Further, the Order directed the ALJs to establish a new litigation schedule for the consolidated case if the Companies agreed to the voluntary extension. On May 22, 2006, the Companies advised the Commission's Secretary that they agreed to extend the effective date of their proposed tariffs to January 12, 2007.

During the period June 20, 2006, through July 13, 2006, nine Public Input Hearings were held in Erie, Warren, Johnstown, Altoona, York, Reading, Mansfield, Towanda, and Bushkill. A total of twenty-four witnesses appeared and offered testimony at these sessions.⁴ Separate transcripts of the proceedings at each session were produced containing a total of 268 pages. On July 20, 2006, a tenth Public Input Hearing was held in Easton. One witness appeared and offered testimony at this session. A transcript of the proceedings was produced containing 25 pages.

By letter dated July 27, 2006, the Companies requested that the Commission make a determination to include the issue of their NUG⁵ purchased power

⁴ Five witnesses testified at Erie, two witnesses testified at Warren, five witnesses testified at Johnstown, one witness testified at Altoona, two witnesses testified at York, five witnesses testified at Reading, no witnesses testified at Mansfield, three witnesses testified at Towanda, and one witness testified at Bushkill.

⁵ A NUG is a non-utility generator, i.e., a generation facility owned and operated by an entity who is not defined as a utility in that jurisdictional area.

accounting methodology in the consolidated case.⁶ By letter dated August 4, 2006, addressed to the presiding ALJs at the Docket Nos. of the consolidated case, the Companies requested approval of the inclusion of their revised NUG purchased power accounting methodology in the consolidated case. On August 11, 2006, the Companies filed correct copies of the Bureau of Audits Reports, correcting attachments to their August 4, 2006 letter request.

By Commission Order adopted August 17, 2006, entered August 18, 2006, in *Metropolitan Edison Company and Pennsylvania Electric Company – Approval of the Reports on the Audit of Non-Utility Generation Related Cost Recovery Through the Competitive Transition Charge for the Year Ended December 31, 2005*, Docket Nos. D-05NUG009 and D-05NUG010, the Commission, among other things, provided:

⁶ The Commission’s Bureau of Audits issued A Report On the Audit of Non-Utility Generation Related Stranded Cost Recovery Through The Competitive Transition Charge For The Year Ended December 31, 2005, for ME at Docket No. D-05NUG009 and for PN at Docket No. D-05NUG010 on August 8, 2006. In each Report, the Bureau of Audits found that the Companies had revised the previously applied NUG accounting methodology effective January 23, 2006, retroactive to January 1999. The revised methodology increased ME’s cumulative undercollection balance by approximately \$19,000,000 and for PN, increased the balance due from the NUG Trust Fund by approximately \$6,000,000. In each Report, the Bureau of Audits recommended that “the Company be directed to revert back to the original NUG cost accounting methodology until such time as the Commission approves an alternative to that methodology.” By Secretarial Letter dated June 30, 2006, the Commission invited comments on the Reports. OSBA and OTS submitted comments supporting the Bureau of Audits’ recommendations. The Companies submitted reply comments requesting that the issue of the revised accounting methodology be addressed in the consolidated case. All comments were filed at Docket Nos. D-05NUG009 and D-05NUG010. By Secretarial Letter dated August 2, 2006, the Commission’s Secretary advised the Companies that its July 27, 2006, letter “is not accepted for filing” at Docket Nos. D-05NUG009 and D-05NUG010. The Companies were further advised that if a similar letter was filed at the dockets of the consolidated case, “any party can file responses to [such a] letter with copies to the presiding ALJs.” The Secretarial letter went on to state that “[a]t that time, the ALJs can address, if appropriate, the issues raised in your letter.”

2. That the Companies revert back to the original NUG cost accounting methodology until such time as the Commission approves a change to that methodology. This Order is not intended to limit the Companies' ability to petition for a change from the accounting methodology utilized by the Companies between January 1999 and January 2006.

3. That the Companies are to adjust the appropriate accounts so as to reflect the balances they would have had absent the Companies' unilateral change in methodology.

4. That consistent with our Secretarial letter dated August 2, 2006, the Companies' proposal to change the NUG cost accounting may be examined in the pending Rate Transition Plan at Docket Nos. R-00061366 and R-00061367, if deemed appropriate by the presiding ALJs. In the event that the ALJs decide that it is not appropriate to examine the change in NUG cost accounting in the pending rate transition plan dockets, the Companies may file a petition as set forth in Ordering Paragraph 2.

Consistent with Ordering Paragraph No. 4 of the Commission's August 18, 2006 Order, it was determined that inclusion of the issue of the Companies' unilateral change in NUG accounting methodology in the consolidated case was not appropriate. It was also ordered that the Companies take all appropriate actions to comply with the Commission's Order so that the information presented in the consolidated case would be in compliance with the Commission Order.

An Initial and further Hearings were held as scheduled on August 24, 25, 28, 29, and 30, 2006. During the course of the Hearing, a total of twenty witnesses appeared and were available for cross-examination. Additionally, the written testimony of another twenty-eight witnesses was received into evidence by stipulation of the Parties. YCSWA, ARIPPA, PPL, RESA, Citizen Power, Sheppard, Pierre Fortis, and L. C. Rhodes presented no witnesses. Numerous statements (many with attached exhibits and/or appendices), exhibits, and cross-examination exhibits sponsored by the Parties

were received into evidence, as were two ALJ exhibits (ALJ Exhibit 1 and 2). A transcript of the proceeding containing 798 pages (numbered 404 through 1201) was produced. The following Parties filed Main Briefs on September 22, 2006: the Companies, OTS, OCA, OSBA, MEIUG and PICA and IECPA, PPL, the SEFs, RESA, PennFuture, Constellation, Citizen Power, Sheppard, CAAP, ARIPPA, and YCSWA. On September 26, 2006, in accordance with the extension of time granted to it, the Commercial Group filed its Main Brief.

The following Parties submitted Reply Briefs on October 6, 2006: the Companies, OTS, OCA, OSBA, MEIUG and PICA and IECPA, PPL, the SEFs, RESA, PennFuture, Constellation, Citizen Power, the Commercial Group, and Sheppard. YCSWA, ARIPPA, and CAAP did not file Reply Briefs.

On October 11, 2006, OCA filed Revised Tables I and II for the PN Transmission Income Summary and Summary of Adjustments, along with an errata sheet changing the text of the OCA Main and Reply Briefs to reflect the revised Tables I and II for PN Transmission Service. On October 16, 2006, OTS filed separate Corrected Tables I and II, Income Summary and Summary of OTS Adjustments, for MEPN.

The Recommended Decision of ALJs Salapa and Weisman, which was served on the Parties on November 2, 2006, rejected the proposed annual increases of \$225,784,000 and \$165,547,000 for MEPN, respectively, and recommended that the Commission issue an Opinion and Order directing MEPN to file a tariff allowing recovery of no more than \$41,470,000 and \$34,288,000,⁷ respectively, in additional base rate revenue. The ALJs also rejected the Companies' proposed rate transition plans. In

⁷ The Recommended Decision, served November 2, 2006, included Tables which did not reflect all of the ALJs' recommended adjustments. In their Reply Exceptions, the Companies provided, in concurrence with the Parties of the proceeding, the necessary adjusted Tables.

the matter of merger savings, it was determined that the Companies would calculate the savings from 2001 to 2006 and allocate 50% of the \$140.4 million to ratepayers. The savings would then be allocated to rate classes on the basis of present distribution revenues and be credited to ratepayers over a four year period, 2007 to 2010.

Exceptions and Reply Exceptions were filed as noted above.

II. MERGER SAVINGS

A. Allocation of Merger Savings

1. Positions of the Parties

The Companies argued that there should be no sharing of merger savings. They asserted that since the merger, FirstEnergy has provided millions of dollars of benefits to customers above and beyond merger savings. If merger savings are directed to customers, that would constitute a windfall to customers. (R.D. at 30).

OSBA and OCA proposed a 50/50 sharing of merger savings. OCA proposed that merger savings be returned to customers over a period of four years. OSBA recommended that merger savings be allocated to rate classes on the basis of present distribution revenues. (R.D. at 30).

Citizen Power and OTS argued that all of the merger savings should be passed on to customers. Citizen Power asserted that any suggestion that FirstEnergy provided financial support which benefited customers is without merit since the customers were insulated from increased power costs due to rate caps. OTS argued that the alleged financial support by FirstEnergy was actually lost opportunity costs, not actual financial support. OTS argued that no money changed hands; accordingly, there can be no basis for asserting that a subsidy occurred. In addition, OTS asserted that to

the extent FirstEnergy experienced lost opportunity costs, that was the result of management decisions of FirstEnergy and the Companies. (R.D. at 30-31).

2. ALJs' Recommendation

The ALJs adopted the OCA and OSBA position which provided for a 50/50 sharing of merger savings between the Companies and ratepayers. The ALJs agreed with Citizen Power that ratepayers have been insulated from increased power prices by rate caps which substantially nullified any suggested financial benefits flowing from FirstEnergy. (R.D. at 31). The ALJs rejected the position of Citizen Power and OTS that all of the merger savings should flow to ratepayers. The ALJs noted that the merger was approved as being in the public interest which extends to providing benefits to the Companies' shareholders and those of FirstEnergy. The ALJs observed that allowing shareholders to share in merger savings would provide an incentive to the shareholders to invest in new facilities and technology. (*Id.* at 32).

With regard to the calculation of the merger savings, the ALJs recommended that shareholders and customers each receive 50% of the merger savings, as calculated by the Companies for the years 2001-2004, and as calculated by OSBA for the years 2005 and 2006. According to the ALJs, that would return \$36.8 million to ME ratepayers and \$33.4 million to PN ratepayers. The ALJs recommended that the savings be allocated to rate classes on the basis of present distribution revenues and shall be a credit to each ratepayer within the rate class. The ALJs also recommended that the merger savings be returned over a four year period. (R.D. at 32).

3. Exceptions

The Companies filed two Exceptions to the ALJs' recommendation on allocation of merger savings. In the Companies' Exception No. 2, they argue that the

ALJs erroneously rejected consideration of the generation support provided by FirstEnergy on the basis that rate caps insulated customers from market prices. However, the Companies assert that this approach ignores this Commission's Opinion and Order in *Joint Application for Approval of Merger of GPU, Inc. with FirstEnergy Corp.*, Docket Nos. A-110300F0095 and A-110400F0040 (May 24, 2001). The Companies state that our Opinion and Order in that proceeding specifically stated that this Commission needed to evaluate "evidence regarding issues such as the specific role FirstEnergy will play in assisting [ME] and [PN], both monetarily and in terms of generation, in meeting their [POLR] responsibilities." (MEPN Exc. at 2-3, citing, *Joint Application for Approval of Merger* at 38).

The Companies argue that the ALJs failed to consider "the over \$700 million in generation-related support FirstEnergy has provided MEPN since the merger." (MEPN Exc. at 3). In addition, the Companies assert that they have absorbed \$143 million of PJM transmission costs in 2005. The Companies argue that allocation of merger savings over and above the support already provided constitutes a windfall to ratepayers. *Id.*

In the Companies' third Exception, they argue that if a sharing of merger savings is directed, a four year period for the credit is arbitrary. The Companies assert that if merger savings are to be allocated to customers, they should be credited over the same time period in which the savings were deemed to have accrued, six years. This is consistent with the ALJs' recommendation for a five year recovery period for deferred universal service costs. (MEPN Exc. at 3).

Citizen Power cites error in the ALJs' recommendation to allocate 50% of the merger savings to shareholders. In its Exception No. 1, Citizen Power argues that the recommended allocation is not supported by substantial evidence and "is not the product of reasoned decisionmaking [sic]." (Citizen Power Exc. at 3). Citizen Power argues that

the standard set forth in *City of York v. Pa. PUC*, 295 A.2d 825 (Pa. 1972), requires that the merger must provide substantial benefits. Accordingly, Citizen Power asserts that the merger savings to be passed through to customers must be substantial to satisfy that standard. Citizen Power states that in order to be considered substantial, the merger savings allocation must be 100% to customers. (*Id.* at 4).

Citizen Power also argues that as originally proposed, FirstEnergy and GPU projected annual company-wide savings of \$150 million as one of the benefits of the merger. However, that amount was reduced by almost half when reduced by severance costs, costs the Companies should have been aware of at the time they stated merger savings as \$150 million. Citizen Power asserts that since the Companies originally supported the merger based on a figure without off-setting severance costs, now that the set-off has occurred, the entire savings should be passed through to ratepayers. (Citizen Power Exc. at 5).

Citizen Power cites error in the ALJs' finding that the "public interest" includes the Companies' shareholders. Citizen Power claims that the ALJs provided no support for this proposition. According to Citizen Power, this analysis means that any merger which simply benefits shareholders would pass the *City of York* standard which is an absurd result. (Citizen Power at 6). Citizen Power also argues that the ALJs' statement that shareholders would have an incentive to invest due to sharing in the merger savings has no support in the record. Citizen Power states that there is no evidence at all which suggests that merger savings have anything to do with whether shareholders will invest in facilities or new technologies. Although increased shareholder investment was stated as a potential merger benefit, Citizen Power asserts that was separate and distinct from merger savings. (*Id.* at 7).

Reply Exceptions to the Companies Exceptions were filed by Citizen Power, OCA, OTS and OSBA. Citizen Power responds to the Companies' Exception

No. 2 and states that the ALJs properly determined that ratepayers were insulated from market prices and any benefit received through the merger in the form of lower power prices was illusory. Citizen Power asserts that the same analysis applies to any claims that the merger permitted an absorption of increased transmission costs since there was a transmission rate cap in place until December 31, 2004. (Citizen Power R.Exc. at 4-8). OSBA replies to the Companies' Exception No. 2 and also asserts that rate cap protections render any suggested company provided benefits inconsequential. OSBA also states that by allocating the savings 50%-50%, the ALJs properly balanced the interests of the ratepayers and shareholders. (OSBA R.Exc. at 2-3). The OCA makes similar arguments in its response and observes that any "benefits" provided by FirstEnergy or the Companies were merely lost opportunity costs, not actual benefits passed through to customers. (OCA R.Exc. at 2-3). OTS makes similar arguments in its response. (OTS R.Exc. at 3).

The Companies respond to Citizen Power's Exception No. 1 and argue that the Commission has never stated that merger savings must be given to customers to pass the *City of York* public interest test. Rather, the Commission indicated that each case must be evaluated on its own. Commitments such as distribution rate reductions to pass through merger savings, improved reliability and environmental issues have all served to indicate that a particular merger was in the public interest. (Companies R.Exc. at 1-3).

Reply Exceptions to the Companies' Exception No. 3 were filed by OCA, OTS, OSBA and Citizen Power. OCA argues that since the ALJs did not include a time value of money adjustment, it was appropriate to return the savings as quickly as possible. The OCA states that a four year period minimizes the impact on the Companies, but is reasonable for customers. (OCA R.Exc. at 3). In its Reply, OTS argued that the four year recovery period will be easier to administer and will return the merger savings to ratepayers faster than the time frame proposed by the Companies. (OTS R.Exc. at 4). OSBA asserts that the Companies have had the use of the merger

savings for six years without paying interest. In addition, OSBA argues that there is no testimony in support of six years. (OSBA R.Exc. at 3-4). Citizen Power argues that the four year period was supported by evidence advanced by OCA, while there is no record support for the Companies' six year proposal. Citizen Power also asserts that the four year period minimizes the impact on the Companies while providing a reasonable time frame for recovery by ratepayers. (Citizen Power R.Exc. at 8-9).

4. Disposition

We will grant the Companies' Exception No. 2. As noted in the Companies' Exception, in the *Joint Application for Approval of Merger*, we stated that we intended to evaluate the record developed on issues such as the role FirstEnergy would play in assisting ME and PN with their POLR responsibilities. (MEPN Exc. at 2-3). In this proceeding, the record reveals that FirstEnergy has provided over \$700 million in generation-related support since the merger. This has been crucial in enabling the Companies to meet their POLR responsibilities post-merger. The Companies also point out that they have absorbed \$143 million in PJM transmission costs in 2005. These benefits substantially exceed the amount of merger savings at issue. (*Id.*) We agree with the Companies that the ALJs failed to accord the appropriate weight to this support.

Various Parties argue that some or all of the generation support provided by FirstEnergy should be discounted as lost opportunity costs or because of existing rate cap protection. As a practical matter, however, the generation support provided by FirstEnergy enabled the rate caps to be maintained. To illustrate this point, the existence of rate caps did not help customers in California when their utilities went bankrupt and electricity had to be procured by the state at market prices. In addition, these arguments ignore the fact that regardless of rate caps or the form of support, FirstEnergy has provided substantial ongoing support of hundreds of millions of dollars to the Companies and the Companies' ratepayers since the merger. In these circumstances, we agree that an allocation of merger savings over and above the support already provided is not warranted.

In the *City of York*, the standard for review of mergers is whether the merger will produce some substantial public benefit in order to support a finding that the merger is in the public interest. In the *City of York*, the Supreme Court upheld the Commission's finding that a merger of three telephone companies would result in affirmative benefits to customers due to improved operations and financial strength. No distribution of merger savings to customers was required in that case. *City of York*, 295 A.2d at 829. Citizen Power argued that in order to meet the *City of York* test, there must be an allocation of a substantial amount of merger savings. (Citizen Power Exc. at 4). However, the standard does not mandate any particular form of benefit, such as an allocation of merger savings. In prior merger proceedings, we have found that commitments relating to reliability and customer service, universal service, staffing and environmental issues were appropriate matters in the examination of whether a merger would benefit the public. *Joint Application of PECO Energy Company, et. al.*, Docket No. A-110550F0160 (February 1, 2006).

Here, we find that the ongoing generation support of over \$700 million as well as absorption of PJM transmission costs for 2005 are substantial benefits fully satisfying the *City of York* standard. There is no need to increase those benefits by allocating a portion of merger savings to ratepayers in order to find that there has been a substantial benefit from the merger. Accordingly, we will grant the Companies' Exception No. 2 and deny Citizen Power's Exception No. 3. The Companies' Exception No. 3 is denied as moot.

B. Amount of Merger Savings

The ALJs found that the amount of merger savings through the end of 2006 is \$140.4 million. The total merger savings attributable to ME for the period 2001-2006 is \$73.6 million and the amount for PN is \$66.8 million. (R.D. at 25). The ALJs also recommended that a four year credit period be established for the flow through of merger savings to customers. The Companies filed Exception No. 1 to the ALJs conclusion that merger savings should have been tracked through 2005 and 2006. Citizen Power filed its

Exception No. 2 arguing that the ALJs erred by failing to include an adjustment for the time value of money and an escalation factor. In view of our disposition of the issue of allocation of merger savings, the issues regarding the amount of merger savings and the credit period are moot. Accordingly, the Companies' Exception No. 1 and Citizen Power's Exception No. 2 are denied.

III. NON-NUG STRANDED COST RECOVERY/NUG COST RECOVERY

A. Non-NUG Stranded Cost Recovery

The ALJs set forth the background of this issue at Pages 32 through 34 of the Recommended Decision. The Restructuring Settlement entered into by the Companies addressed the recovery of stranded costs together with a myriad of other issues.⁸ The Companies agreed in the Restructuring Settlement that their non-NUG stranded costs would be recovered by means of a Competitive Transition Charge (CTC) which would last from January 1, 1999 through December 31, 2010 for ME and through December 31, 2009 for PN. There is no provision for an extension of the time for recovery of non-NUG stranded costs. NUG stranded costs are permitted to be recovered for a longer period of time, provided that recovery is terminated no later than December 31, 2020. (ALJ Exh. 1, at B.1, B.2).

It is important to note that the Companies were required to account for non-NUG stranded cost recovery and NUG stranded cost recovery separately. However, the Companies had the opportunity to recover both types of stranded costs through the CTC and could decide how much of the CTC revenue would be allocated to which type of stranded cost. Also, the Companies were permitted to recover carrying charges on the non-NUG stranded costs, but none on the NUG stranded costs. At the time of the

⁸ The Restructuring Settlement has been placed in the record in this proceeding as ALJ Exhibit 1.

hearings in this proceeding, ME has non-NUG stranded costs yet to be recovered. PN has no non-NUG stranded costs, but proposes to utilize the CTC to recover certain claimed nuclear decommissioning costs. (R.D. at 32-35).

1. Positions of the Parties

Before the ALJs, ME asserted that it would not be able to recover its full non-NUG stranded costs prior to December 31, 2010. Accordingly, ME proposed to add carrying charges to the NUG CTC balance to match the carrying charges of 10.4% now in place for the non-NUG balance. ME argued that this would be economically indifferent to customers, since the overall CTC would not change because more CTC revenue could be allocated to the non-NUG stranded costs and recovery of the NUG balance would be delayed. ME also stated that although the overall CTC would not be changed, the unchanged CTC revenue requirement would have to be reallocated by rate group in order to permit full collection of the non-NUG stranded costs by rate class within the required time frame. As an alternative, ME suggested that the Commission could increase its CTC by 0.004¢ per kWh in order for ME to fully recover its non-NUG stranded costs within the required timeframe. (R.D. at 35).

OSBA, OCA, OTS, the Commercial Group and MEIUG/PICA all oppose ME's initial proposal relating to the addition of carrying charges to the NUG stranded cost balance and the increase in the non-NUG CTC. These Parties noted that the Restructuring Settlement permitted ME to apply CTC revenues to either type of stranded cost. These Parties then argued that ME chose to apply CTC revenues towards its NUG stranded cost balance because the NUG balance did not earn a carrying charge. By failing to assign an appropriate amount of CTC revenue to the non-NUG stranded cost balance, these Parties argue that ME must bear the responsibility of failing to collect its full non-NUG stranded costs within the time frame dictated by the Restructuring Settlement. These Parties assert that either option proposed by ME is an increase in the

amount of ME's CTC recovery which is solely the result of ME's decision to allocate more CTC revenues to NUG stranded cost than non-NUG stranded cost due to the fact that NUG stranded costs did not earn a carrying charge. (R.D. at 35-36).

2. ALJs' Recommendation

The ALJs recommended rejection of the ME proposals. The ALJs agreed with the opposing Parties that ME made a business decision to allocate CTC revenues to its NUG stranded cost balance because that balance did not earn a carrying charge. The ALJs stated "[i]t chose to pay off the NUG balance first so that it could earn a return on the unpaid non-NUG balance. [ME] did this knowing that the Restructuring Settlement provided a deadline for recovering its non-NUG stranded costs of December 31, 2010." (R.D. at 37). The ALJs further concluded that given the shorter timeframe for recovery of non-NUG stranded costs, "logic" dictated that ME would have assigned more CTC revenue to the stranded cost balance with the shortest collection period. However, ME did the opposite with predictable results. *Id.*

The ALJs determined that if there is a shortfall in ME's non-NUG stranded cost recovery, it is the predictable result of ME's decision to allocate more CTC revenues to NUG stranded cost recovery. The ALJs noted that ME still has the option to shift CTC revenues to the non-NUG stranded cost balance and may do so at any time. However, since the asserted short-fall in non-NUG stranded cost recovery is the result of ME's voluntary decision on CTC revenue allocation, the ALJs recommend rejection of ME's proposed adjustments. (R.D. at 37).

3. Exceptions

ME excepted to the ALJs' recommendation arguing that the recommendation erroneously "concludes that Dec. 31, 2010 is an absolute 'deadline' for

recovery of all non-NUG stranded costs, and that the non-NUG CTC can neither be adjusted to meet that deadline, nor extended so as to provide full cost recovery.” (Companies Exc. at 4). In their Exception No. 4, the Companies argue that the Restructuring Settlement provided ME with the “absolute right” to allocate CTC revenues between non-NUG and NUG stranded costs. Yet, the thrust of the recommendation is that ME must in some manner be faulted for that allocation. *Id.*

According to ME, the recommendation ignores the fact that the Commission can adjust CTC levels to ensure full stranded cost recovery. In addition, the deadline for non-NUG stranded cost recovery was stated as an “initial” target. (Companies Exc. at 4). In order for ME to fully recover the amount of stranded costs set forth in the Restructuring Settlement, the Companies assert that one of their proposals must be adopted. In addition, ME argues that in order for it to more fully collect its non-NUG stranded costs by rate class by the December 31, 2010 deadline, the CTC revenue requirement must be reallocated by rate group consistent with ME’s proposed Cost of Service allocations. ME states that it appears that the ALJs allowed that reallocation. (*Id.* at 4-5).

OCA, OTS, OSBA and MEIUG/PICA filed replies to the Companies’ Exception No. 4. OCA states that the effect of the Companies’ proposal is to increase the NUG stranded cost award through the application of interest. However, the need for the Companies’ proposal is the result of the Companies’ voluntary decisions on how to recover their various stranded costs. The Companies’ proposal contradicts the agreed upon terms of the Restructuring Settlement and must be rejected. (OCA R.Exc. at 4). Similarly, OTS asserts that the Companies’ situation is one of their own making, that the Restructuring Settlement does not provide for the Companies’ proposal and that the Companies should be left with the consequences of their decisions. (OTS R.Exc. at 5). OSBA and MEIUG/PICA make similar responses. (OSBA R.Exc. at 4; MEIUG/PICA R.Exc. at 12-13).

4. Disposition

We will deny the Companies' Exception No. 4. The Companies are correct that their Restructuring Settlement provided ME with some discretion as to the method for recovering non-NUG and NUG stranded costs. However, the record amply supports the ALJs' determination that the Restructuring Settlement also provided a deadline for the collection of non-NUG stranded costs. In addition, the Restructuring Settlement does not provide for any extension of that deadline. (R.D. at 37; ALJ Exh. 1 at 13-14, ¶¶ B1 and B2). Accordingly, the date for achieving full collection of non-NUG stranded costs was not an "initial" target as suggested by the Companies. Given that deadline, it was incumbent upon ME to exercise its discretion in such a fashion that the non-NUG stranded cost deadline would be met.

We agree with the ALJs that ME decided to structure its stranded cost collection in a manner that would permit it to earn as large a return on the unpaid non-NUG balance as possible. The result of that decision is that absent a change in the collection structure, ME will not meet the deadline for its non-NUG stranded cost collection. This is a result readily apparent to ME and should have been considered when structuring its stranded cost collection. It is simply giving full effect to *all* of the Restructuring Settlement's terms, including the deadline for collection of non-NUG stranded costs. We also agree with the OCA's position that adoption of ME's proposal to add carrying charges to the NUG balance in order to make up for the shortfall is an attempt to increase the stranded cost award set forth in the Restructuring Settlement. Similarly, we do not find that the ALJs recommended adoption of the Companies' proposed reallocation. We agree with the ALJs and also deny the proposed reallocation of the CTC revenue requirement.

B. Non-stranded NUG Costs

1. Positions of the Parties

The Companies proposed to defer for future recovery certain NUG related costs that are not deemed stranded costs recoverable through the CTC. The Companies took the position that NUG market value was comprised of NUG LMP (locational marginal pricing) and capacity cost, or NLACC. The Companies asserted that going forward, the NLACC will be substantially greater than the generation revenue (based upon the shopping credit) they will recover from POLR customers. The Companies request an accounting order from the Commission to defer as a regulatory asset, for future recovery, the amount by which the NLACC exceeds the POLR generation rates. ME's projected deferral is \$87.3 million and PN's projected deferral is \$108.2 million. (R.D. at 34).

The Companies proposed to defer collection of the deferred costs to a time when the existing CTC could be reduced. Collection would occur through a new reconcilable non-CTC rider which could be assessed in an amount equal to the reduction in the CTC amount thus having no impact on the over-all CTC charge to customers. A carrying charge would be included on the balance to be collected. The non-CTC rider (termed the NUG Service Charge rider by the Companies, or NSC) would be assessed on all distribution customers. (R.D. at 38).

Alternatively, the Companies proposed that the Commission could approve an NSC rate in addition to base rates which would be implemented in 2007. That NSC rate would be set initially to recover the difference between the NLACC and generation charges projected for 2007. Thereafter, the NSC would be reconciled with actual data. The NSC would continue as long as POLR was supplied by NUGs. A third alternative was proposed which provided for an NSC rate in addition to base rates that would recover the difference between the test year generation rate and the NLACC. The

Companies stated that any of the three proposals could be adjusted to account for any period in which the generation revenues actually exceeded the NLACC to prevent over-recovery. (R.D. at 39).

The Companies argued that failure to recommend adoption of any of the NSC alternatives would violate State and Federal law by refusing to permit the Companies to fully collect NUG costs. They cite to *Freehold Cogeneration Associates, LP v. Board of Regulatory Commissioners*, 44 F.3d 1178 (3rd Cir. 1995), *cert. denied*, 516 U.S. 815 (1995) and *Petition of Pennsylvania Electric Company, Re: Agreement with Scrubgrass Power Corp.*, Docket No. P-870248 (Order entered January 21, 1988). According to the Companies, these decisions stand for the proposition that the Companies are entitled to recover their full NUG costs. (R.D. at 42).

OSBA, OCA, OTS, the Commercial Group and MEIUG/PICA opposed all three of the Companies' proposals. OSBA, OCA, the Commercial Group and MEIUG/PICA argued that the Restructuring Settlement established the methodology for calculating NUG stranded costs, provided for recovery of those costs and provided for full recovery of those costs. According to these Parties in opposition, the Companies are simply trying to recalculate NUG stranded costs in a manner more favorable than the Restructuring Settlement, label them as something other than stranded costs and pursue collection outside of the CTC. These Parties also argue that any "losses" stated by the Companies are illusory since they could sell NUG power on the open market at the NLACC price and avoid those losses. To the extent that replacement power must be procured for POLR, that replacement power would be governed by the rate cap provisions of the Restructuring Settlement. (R.D. at 40).

OTS proposed that NUG costs which are to be collected under the NSC should be collected beginning in 2007. The NUG expense shortfall should be collected through the maximum generation rate proposed by OTS. OTS argues that this is better

than the Companies' proposal since the OTS maximum generation rate is lower than that proposed by the Companies, except for PN's 2007 rate if a generation rate increase is granted here. In addition, OTS argues that its alternative avoids the carrying charges proposed by the Companies since no deferral is provided. Also, by providing for immediate collection, the customers who incur the costs will be paying the costs. (R.D. at 41).

2. ALJs' Recommendation

The ALJs recommended rejection of the Companies' NSC proposal. They agreed with OCA, OSBA, the Commercial Group and MEIUG/PICA that the Companies were simply attempting to package a change in NUG stranded cost methodology as something other than stranded costs to the Companies' advantage. The Companies' proposals were deemed to be inconsistent with the Restructuring Settlement, which was deemed to be in accordance with both case authorities cited by the Companies. The ALJs also agreed that any "losses" as described by the Companies could be eliminated if the Companies sold the NUG power on the market at market prices. Finally, the ALJs agreed with the OCA that the only tenable argument available to the Companies would be if they had new NUG projects which post-dated the Restructuring Settlement. Since that is not the case, the ALJs recommend rejecting the Companies' proposals. (R.D. at 41-42).

3. Exceptions

The Companies argue that the ALJs and the opposing Parties confuse the issue involving ongoing NUG costs. In their Exception No. 5, the Companies argue that nothing in their proposals seeks to modify the Restructuring Settlement. According to the Companies, the ALJs erred by ignoring the distinction between NUG stranded costs and the recovery of non-stranded NUG costs. The Companies assert that the difference

between the NUG contract price and the NLACC are recoverable under the Restructuring Settlement as stranded costs. However, the difference between the generation charge (or shopping credit) and the NLACC does not fall under the stranded cost definition. (Companies Exc. at 5-6).

The Companies further argue that because the costs they seek to recover through the NSC are not stranded costs, they are ongoing NUG costs which are covered by the *Freehold* and *Scrubgrass* decisions which mandate full recovery of ongoing NUG costs. In addition, the Companies cite to Section 527 of the Public Utility Code (Code), 66 Pa. C.S. § 527, which mandates recovery of all NUG-related costs. Accordingly, since the costs which the NSC is designed to recover are not included in the CTC, they must be recovered through a combination of the generation rate and a mechanism designed to operate when the generation rate is less than the NLACC. (Companies Exc. at 8-9). The Companies further argue that the suggestion that they could avoid losses by selling NUG power into the market would deny the benefits to the Companies' customers of the NUG power for which they are paying stranded costs. (*Id.* at 9).

OCA, Constellation, OSBA and MEIUG/PICA responded to this Exception. OSBA asserts that the Companies' proposal "is simply a back-door attempt to change the calculation of NUG stranded costs, a fact which the ALJs recognized and a position which they rejected." (OSBA R.Exc. at 5). OCA argues that the Companies' proposal is "an attempt to either increase future NUG stranded cost recovery or to break the generation rate caps while couching the recoveries in NUG-related terms." (OCA R.Exc. at 5). The OCA asserts that the effect of the proposal is to value NUG stranded cost based on the POLR rate rather than market price. That increases the amount of NUG stranded costs in violation of the Restructuring Settlement. (*Id.* at 6). MEIUG/PICA advances arguments similar to those made by OSBA and OCA. (MEIUG/PICA R.Exc. at 14-15). Constellation argues that the Companies' proposal is actually an effort to collect increased generation costs. As such, any collection methodology must be properly

reflected as generation costs and be by-passable by customers served by an EGS.
(Constellation R.Exc. at 1-4).

4. Disposition

Our review of the Companies' Exception No. 5 begins with the Restructuring Settlement and its treatment of NUG costs. With regard to NUG costs, the Restructuring Settlement provides:

The Joint Petitioners agree that this Settlement and the NUG cost recovery mechanism provided for in Parts B and C herein, initially through the CTC and subsequently through a separate recovery mechanism for each Company, shall be deemed to constitute and provide for full and actual cost recovery of all costs and charges incurred by the Companies for (1) energy and capacity under and in compliance with existing NUG agreements identified in Appendix F ("NUG Agreements"), and (2) voluntary buyout, buydown or restructuring of the NUG Agreements.

(ALJ Exh. 1 at 61).

According to the foregoing language, agreed to by the Companies, the NUG cost recovery set forth in the Settlement Agreement provides for "full and actual cost recovery" of *all* of the Companies' NUG costs. There is no need to change that methodology in this proceeding as the Companies have already agreed that the Settlement Agreement methodology is appropriate and adequate.

Moreover, the Companies further agreed that:

So long as GPUE [the Companies] receives full recovery of its NUG-related stranded costs consistent with the terms of this Settlement, the Companies further agree not to make any argument or claim before any state or federal court of administrative body, including but not limited to the

Commission and the FERC, based on a contention that the Settlement or the Commission's orders in the GPUE restructuring proceedings provide for inadequate recovery of GPUE's NUG-related costs, and shall assert that any such claim or argument raised by another party should be dismissed with prejudice.

(ALJ Exh. 1 at 61-62).

The Companies' arguments in this proceeding are efforts to change the balance struck by the foregoing provisions of the Restructuring Settlement. The Companies argued before the ALJs that failure to approve this claim and one of the three proposed collection alternatives would be a violation of Section 527 of the Code, 66 Pa. C.S. § 527, and the decisions in *Freehold* and *Scrubgrass*. However, that argument is put to rest by the Companies' own agreement in the Restructuring Settlement that all of their NUG costs will be fully recovered through the methodology provided in the Restructuring Settlement. Should any doubt arise about the Companies' intent in that agreement, the Companies agreed to move to dismiss, in any forum, any assertion that the Restructuring Settlement fails to provide for an adequate recovery. In the face of such explicit terms, we are not persuaded by the Companies' arguments here.

Alternatively, the Companies argue that the ALJs confused stranded costs with ongoing NUG costs in rejecting this claim. This argument is unpersuasive as well. MEIUG/PICA effectively argued that the very costs described by the Companies are encompassed by Section 2803 of the Electricity Generation Customer Choice and Competition Act (the Competition Act), 66 Pa. C.S. §§ 2801, *et seq.*, § 2803. (MEIUG/PICA M.B. at 41). However, even if the Companies' argument is considered, then these costs would constitute generation costs subject to the generation rate caps. As noted by the ALJs, the Companies could sell the NUG power on the open market and avoid any losses so that Section 527, *Freehold* and *Scrubgrass* are followed. Any replacement power purchased would be subject to the generation rate caps. Regardless,

we agree with the analysis which finds that these costs are covered by the Restructuring Settlement in which the Companies agreed that the collection methodology provided for full recovery of those costs. The Companies' Exception No. 5 is denied.

IV. GENERATION RATE CAP

The ALJs discussed the Companies' proposal to establish generation rates above current rate cap levels at Pages 42 through 69 of their Recommended Decision. Included in that discussion is a thorough examination of the background of the rate caps, the Restructuring Settlement and the Competition Act. We will summarize some of that discussion here before moving to a discussion of the various arguments on this issue.

One of the concerns expressed in the Act was the desire to ensure that the transition to an open retail market for electricity would be as smooth as possible. *See*, 66 Pa. C.S. §§ 2802(8), (9), (10), (11) and (12). One way to accomplish that type of transition was that rate caps were placed on generation, transmission and distribution rates for the same amount of time that an electric distribution company (EDC) was to collect stranded costs from customers and that EDC's customers had full access to a competitive market, whichever was shorter. 66 Pa. C.S. § 2804(4)(i) and (ii). For the Companies, their Restructuring Settlement provided for a cap on transmission and distribution charges until December 31, 2004. For generation, the Companies' rate cap was extended to December 31, 2010. However, given the extension of the rate cap to December 31, 2010, the Companies were permitted to put an increase in the generation rate cap in effect on January 1, 2006 by 5% over the generation rates initially set in the Restructuring Settlement. (R.D. at 46).

Although the Restructuring Settlement provided for a generation rate cap through 2010 for both Companies, the Restructuring Settlement expressly provided that

the Companies could seek an exception to the rate cap pursuant to Section 2804(4)(iii) of the Act, 66 Pa. C.S. § 2804(4)(iii). That Section reads in pertinent part:

An electric distribution utility may seek, and the commission may approve, an exception to the limitations set forth in paragraphs (i) and (ii) [relating to rate caps] 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).

* * * *

(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.

* * * *

(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.

* * * *

66 Pa. C.S. § 2804(4)(iii).

The ALJs also discussed the merger of GPU (the Companies' former parent) and FirstEnergy. As stated by the ALJs, FirstEnergy and GPU averred that "the combination of their resources, years of utility experience, and expertise of the two companies would enhance the capabilities of Met-Ed and Penelec so that those

subsidiaries could fulfill their obligations to provide safe, adequate, and reliable service to their retail customers in Pennsylvania.” (R.D. at 48, quoting *ARIPPA*, 792 A.2d at 645). In that vein, the ALJs observed that FirstEnergy had a corporate supply portfolio that included a generation affiliate, FirstEnergy Solutions (FES), as well as the indication that FirstEnergy “would be in a position to provide additional assistance to GPU Energy in meeting its [POLR] obligations.” (*Id.*, quoting *ARIPPA*, 792 A.2d at 646). The ALJs stated: “FirstEnergy’s acknowledgment of this obligation, combined with the offering of FES’s generation services, suggested that the Companies, under the helm of FirstEnergy, were ready, willing, and able to ensure POLR supply for Met-Ed and Penelec’s customers through 2010.” (R.D. at 48).

The ALJs then described the relationship between FES and MEPN post-merger. The ALJs noted that FES entered into a Partial Requirements Agreement (FES Agreement) under which FES agreed to provide the additional power the Companies needed to meet their POLR obligations.⁹ The FES Agreement had a term of one year after which it could be terminated on short notice. For several years, the FES Agreement worked well, particularly in those years when the market cost of power was less than the rate cap. However, in 2004, it became “reasonably certain” that the market cost of power would remain above the rate cap. (R.D. at 49). At that point, FES explored other options and, in November of 2005, FES gave notice that it would terminate the FES Agreement in accordance with its terms. After several extensions, FES notified the Companies that the FES Agreement would be terminated effective December 31, 2006. “In light of this termination, Met-Ed and Penelec now seek relief from the Commission by requesting that the generation rate cap be lifted so that ratepayers can be held liable for the costs of the Companies procuring POLR supply from third-party suppliers at higher market prices.” (R.D. at 50). (Footnote omitted).

⁹ The ALJs noted that the FES Agreement was to supply approximately 32% of the Companies’ POLR needs at rate cap levels. (R.D. at 48, n. 29).

We will examine the Companies' request for an exception to their generation rate caps against the foregoing backdrop.

A. Positions of the Parties

The Companies' first argument in support of a rate cap exception asserted that the request is consistent with the Restructuring Settlement. The Companies argued that Section D.4 of the Restructuring Settlement provides for the possibility of an exception. Section D.4 of the Restructuring Settlement provides, in part:

The Joint Petitioners agree that the rate cap exceptions set forth in Section 2804(4) of the [Act] shall apply to the rates set forth in this Settlement, except as otherwise specifically set forth herein.

(ALJ Exh. 1, § D.4).

The Companies then argued that Section F.9 of the Restructuring Settlement provides an independent, specific exception to the rate cap other than Section 2804(4) of the Act. According to the Companies, they endeavored to provide for a competitive POLR offering consistent with the Restructuring Settlement in which independent bidders were to assume some or all of the Companies' POLR obligation. When that competitive POLR program (called "CDS" in the Restructuring Settlement) failed to materialize, the Companies argued that Section F.9 of the Restructuring Settlement provides that a new rate cap will be established upon petition to the Commission. (R.D. at 51).

Alternatively, the Companies argued that they met the statutory standard for rate cap relief under Section 2804(4) of the Act. They argued that the market cost of power exceeded the rate cap to such an extent that the Companies could not earn a fair rate of return. In addition, the Companies asserted that the increase in cost was beyond

their control. Noting that the *ARIPPA* decision had resulted in the denial of the Companies' prior request for a rate cap exception, they argued that the circumstances have substantially changed since that decision. Accordingly, while *ARIPPA* is the current state of the law regarding Section 2804(4) standards for rate cap exceptions, the situation now facing the Companies no longer compares to the facts analyzed in that case. (R.D. at 58-65).

Finally, the Companies argued that the Restructuring Settlement should be modified because it is no longer in the public interest. They pointed to Section 703(g) of the Code, 66 Pa. C.S. § 703(g), and observed that the Commission has the authority to amend or rescind any of its orders. The Companies argued that the financial circumstances they face are of such a nature as to warrant an exception to the rate cap under the Commission's general authority to reconsider and modify the Restructuring Settlement.

OCA, OSBA, OTS, MEIUG/PICA, the Commercial Group and Citizen Power all opposed the Companies' request. These Parties disagreed with the Companies' argument that the Restructuring Settlement provided any alternative to the rate cap exception found in Section 2804(4) of the Act. (*See, e.g.*, OCA M.B. at 15-23; OSBA M.B. at 61-66; MEIUG/PICA M.B. at 16-22). The Parties in opposition agreed that the Restructuring Settlement provided an opportunity for the Companies to seek an exception to the rate cap. However, they asserted that any such request must be processed under the statutory exception found in the Act, as that was interpreted by the Commonwealth Court in *ARIPPA*.

The opposing Parties argued that the Companies failed to meet either standard in Section 2804(4)(iii)(D) to justify an exemption. First, these Parties argued that the Companies failed to show that their financial circumstances were beyond their control. For example, MEIUG/PICA argued that the Companies engaged in supply

acquisition strategies that were similar to those that the *ARIPPA* decision found to be within the Companies' control and failed to protect against the risks of a volatile supply market. (MEIUG/PICA M.B. at 23-24). In this regard, MEIUG/PICA noted the FES Agreement and its termination provisions which wholly favored FES and utterly failed to protect the Companies. According to the MEIUG/PICA, the Companies could hardly have been surprised that the FES Agreement would be terminated when prices rose, yet they failed to take any action to either alter the terms of the FES Agreement or hedge the risks of termination. *Id.*

MEIUG/PICA asserted that the foregoing situation was a calculated business risk taken by the Companies under the FirstEnergy umbrella which served the interests of FirstEnergy shareholders while failing to provide for the Companies' known POLR obligation. MEIUG/PICA argued that this is the identical situation confronted in *ARIPPA*, where the Commonwealth Court found that kind of strategy did not meet the test of Section 2804(4)(iii)(D) of the Act. (MEIUG/PICA M.B. at 24-28).

These Parties also argued that the Companies failed to show that they would be unable to earn a reasonable rate of return as a result of increased power supply costs. OCA argued that to the extent the Companies asserted that they could not earn a reasonable rate of return, the Companies' calculations were "wholly inconsistent with traditional ratemaking and result solely from the threatened actions of their affiliate." (OCA M.B. at 33). OCA also argued that the Companies calculated their rates of return by assuming that FES will not supply power at the rate cap price. Then, they assumed all other expenses were as proposed by the Companies, but assumed revenues as proposed by OCA without making any of the expense adjustments proposed by OCA. According to OCA this methodology completely skewed the rates of return calculation. Had proper ratemaking techniques been employed, OCA testified that the Companies would have the opportunity to earn the return on equity allowed by the Commission and the Federal Energy Regulatory Commission "on the applicable jurisdictional investments." (OCA

M.B. at 33, quoting OCA St. 3S at 23). The Parties opposing the Companies' request also disagreed that Section 703(g) of the Code helped the Companies in any way. (*See, e.g.,* OCA M.B. at 35-40).

B. ALJs' Recommendation

The ALJs recommended rejection of the Companies' request for an exception to the rate cap. First, the ALJs found that the Restructuring Settlement did not provide for any standard for an exception independent of Section 2804(4)(iii) of the Act. (R.D. at 52-57). Once that determination was made, the ALJs reviewed the record in light of Section 2804(4)(iii)(D) and *ARIPPA*. According to the ALJs, nothing has changed in the Companies' approach since *ARIPPA* that would warrant a different result. (*Id.* at 59).

The ALJs determined that the Companies' divestiture of generation assets continued to be a factor that affected their affairs at this point in time. *ARIPPA* had already determined that divestiture and the Companies' subsequent actions were within their control and failed to satisfy one of the two prongs of Section 2804(4)(iii)(D). Then, according to the ALJs, the issue became whether circumstances have changed sufficiently since the decision in *ARIPPA* to warrant a different result. They found that no such change had occurred. (R.D. at 61-67). The ALJs found that cancellation of the FES Agreement "was a strategic business decision designed to maximize the profit of an unregulated affiliate over the POLR needs of the Companies." (*Id.* at 64). On that basis, the ALJs determined that this was almost identical to the Companies' previous strategy which was found to be within the Companies' control in *ARIPPA*. The ALJs stated: "As the Court has already decided, it is illegal to shift the risk of the Companies' business decisions to ratepayers." (R.D. at 64, citing *ARIPPA*, 792 A.2d at 665).

The ALJs next addressed the Companies' argument that it was in the public interest to modify the Restructuring Settlement which the ALJs determined to be a request for reconsideration pursuant to Section 703(g) of the Code. In that regard, the ALJs found that the Companies had failed to demonstrate "the type of financial harm that could warrant such an extreme outcome." (R.D. at 66). The ALJs pointed to testimony which established that other Pennsylvania EDCs face the same or similar circumstances now faced by the Companies. Those EDCs also have unregulated supply affiliates that are foregoing higher profits while providing POLR supply at rate cap prices. The ALJs noted testimony indicating that FirstEnergy's shareholders own all of FirstEnergy and its regulated and unregulated companies, including MEPN. The ALJs also noted that FirstEnergy and its shareholders have experienced financial gains in the post-merger period, noting that FirstEnergy's 2006 earnings are "at an all time high." (R.D. at 67). Accordingly, the ALJs found that there is "absolutely no basis to modify the Restructuring Settlement." (*Id.* at 68).

C. Exceptions

The Companies filed five separate Exceptions to the Recommended Decision regarding their request for an exception to the rate cap. In Exception No. 6, the Companies assert that the Commission should grant relief based upon the Restructuring Settlement or amend the Restructuring Settlement in order to do so. The Companies argue that the ALJs ignored portions of the Restructuring Settlement relating to the CDS. According to the Companies, the failure of the CDS program left the full POLR load with the Companies. The Companies argue that this clearly supports their view that failure of that program justified an exception to the rate cap. In this context, the Companies argue that the ALJs erred by viewing Section F.9 of the Restructuring Settlement as a "process" section for managing a Section 2804(4)(iii)(D) request rather than as an independent exception to the rate cap. (Companies Exc. at 9-10). The Companies also assert error in the ALJs' denial of relief under Section 703(g) of the Code. They assert that the

“evidence clearly compels amending the 1998 plan to restore the intended balance.” (Companies Exc. at 12).

Next, the Companies argue that the ALJs misconstrued *ARIPPA* and expanded the holding of that case to issues not before the Commonwealth Court at that time. The Companies assert that the focus of *ARIPPA* was the Companies’ power procurement decisions pre and post-divestiture. The Companies argue that the ALJs interpreted *ARIPPA* as finding that the Companies divestiture was a poor business decision, within their control and thus failed the control standard under Section 2804(4)(iii)(D). However, that issue was not before the Court. In order to reach their conclusion, the Companies also argue that the ALJs failed to recognize “the corporate separateness” of the various FirstEnergy subsidiaries. (Companies Exc. at 12-13). To the extent the ALJs expanded their view to encompass FirstEnergy at the holding company level, the Companies argue they have erred and gone beyond what is required under Section 2804(4)(iii)(D) of the Act which specifically limits the focus to the involved utility. (*Id.* at 13). Thus, according to the Act, it was only the Companies, not any affiliates or the holding company, that were subject to examination under the statutory test. (*Id.* at 14-15). On that basis, the power supply pricing issues faced by the Companies at this time are beyond their control. *Id.*

In Exception No. 7, the Companies argue that the ALJs appear to find that FirstEnergy agreed to take on the POLR obligation of the Companies as part of the Merger proceeding. The Companies argue that the ALJs blurred the distinction between the Companies and FirstEnergy’s unregulated affiliates. Also, the Companies argue that there is no record evidence to support any suggestion that FirstEnergy agreed to support the Companies’ POLR supply. (Companies Exc. at 16).

The Companies argue that since there is no legal obligation of FirstEnergy to provide POLR power at below-market prices, there is no legal significance to the

financial performance of FirstEnergy, FES's costs to supply power or FirstEnergy's Ohio utilities' commitment to POLR supply in Ohio. (Companies Exc. at 16). Similarly, the Companies argue that just as the Commission would not expect the Companies to support inadequate financial performance by FirstEnergy's Ohio utilities and unregulated affiliates, the Commission cannot expect those entities to support inadequate financial performance by the Companies. (*Id.* at 17). Finally, the Companies assert that the Commission has no authority to direct FES to provide POLR power supply to the Companies at below market rates. Wholesale power transactions are under the jurisdiction of the Federal Energy Regulatory Commission. (*Id.* at 18).

In Exception No. 8, the Companies argue that the record is devoid of any support for the proposition that the Companies failed to act to protect themselves and chose to rely on short term agreements. The Companies assert that the record contains substantial evidence that they pursued accepted risk management strategies and pursued all reasonable avenues to procure long-term, fixed price contracts. To a large extent, the Companies were successful; however, there were not enough of such contracts to provide all of the Companies' POLR needs. Accordingly, there was simply nothing more the Companies could have done. (Companies Exc. at 18-19).

The Companies assert in Exception No. 9 that the ALJs erred to the extent they state that the Companies and their officers "violated unspecified fiduciary obligations, were motivated only by a desire to increase profits at the expense of customers and that, as a result, the current problems are 'of their own making.'" (Companies Exc. at 19, quoting the R.D. at 61-65). The Companies acknowledge that many of their officers are also officers of FirstEnergy, "as is typical for a holding company system." *Id.* However, that does not equate to some failure on the part of those offices by failing to ensure that the FES Agreement provided for a term coextensive with the Companies' POLR obligation. Had the FES Agreement contained terms suggested by the ALJs, it would not have been "commercially and economically supportable." (*Id.*

at 20). Unaffiliated suppliers were not willing to offer long-term, fixed price contracts without termination rights. The fact that the FES Agreement lasted as long as it did attests to the willingness of FES to continue the uneconomic arrangement because of its affiliation with the Companies. *Id.*

Contrary to some assertions, the Companies argue that FirstEnergy made it clear in the merger proceeding that it could not assume the Companies' "full POLR obligations regardless of commercial practicability." (Companies Exc. at 21). The Companies assert that FirstEnergy is now being criticized for taking steps that it was never obligated to take in the first instance. *Id.*

In Exception No. 10, the Companies argue that the record establishes that they are not in the same position as other Pennsylvania EDCs. Accordingly, the ALJs are in error to the extent that they find that the Companies must pursue the same or similar power acquisition measures. First, the Companies argue that no other EDC had a provision for at least an 80% bid-out of POLR load (the CDS program). Next, with regard to PPL, the Companies argue that PPL divested its plants at book value to an affiliate, did not reduce its stranded costs as a result of the sale, the affiliate provides a full requirements power supply and PPL and its affiliate have sufficient capacity to service all of PPL's POLR load. By contrast, the Companies divested their generation to third parties, they reduced their stranded costs as a result of the sale, they and their affiliates do not have sufficient supply to serve all of their POLR load and the Companies' affiliate provides more costly, residual, peaking supply. The Companies assert that these factors clearly distinguish them from other Pennsylvania EDCs and indicate that a different supply situation exists. (Companies Exc. at 21-22).

Constellation also filed its Exception No. 1 to the ALJs' comment, that Constellation's argument did not present a cogent legal basis that rates should be more closely aligned with market prices. (Constellation Exc. at 4-7). Constellation argues that

the proposed adjusted rates would remain below market prices during the transition period. Accordingly, Constellation asserts that the proposed rates will serve as barriers to competition since competitors will be unable to compete with the Companies' POLR rates. Constellation observes that the record indicates there are no competitive offerings in the Companies' territory at this point and the proposed rates will do nothing to alter that. On that basis, Constellation argues that if any adjustment to rates is made, the adjustment should be to align the rates "to more closely approximate the Companies' projected market prices during the remainder of the transition period." (Constellation Exc. at 7).

OCA, OTS, OSBA, MEIUG/PICA, the Commercial Group, Citizen Power, PPL and Sheppard filed replies to the Companies' Exceptions concerning the exception to the rate cap. With regard to the Companies' argument that their Restructuring Settlement provided for an exception to the rate cap upon the failure of the CDS program, the OCA asserts that any exception provided by the Restructuring Settlement must be governed by the standards set forth in Section 2804(4)(iii) of the Act. (OCA R.Exc. at 7-9). The OCA argues that the Companies' reliance on Section F.9 of the Restructuring Settlement was misplaced. According to the OCA, the ALJs were correct when they determined that Section F.9 merely provided for an expedited process for the review of any requested exception, but that the standard to be met was as set forth in Section 2804(4)(iii). Most of the other Parties filing Replies made similar arguments. (*See, e.g.*, MEIUG/PICA R.Exc. at 4-5; OSBA R.Exc. at 6; Sheppard R.Exc. at 2, PPL R.Exc. at 2-5).

In response to the Companies' argument in support of reconsideration and modification of the Restructuring Agreement, the opposing Parties argue that there is no record support for reconsideration. The OCA states:

The OCA submits that there is no sound basis for altering the Restructuring Settlement. Indeed, Met-Ed and Penelec are in no different situation than any other Pennsylvania utility that is buying power from its generation affiliate to meet the obligations of its Restructuring Settlement. Those other utilities' generation affiliates are foregoing potential, additional profits which is what the Companies complain of here. The Companies have not provided a reasonable basis to rescind or modify the Commission's Order that approved the Restructuring Settlement.

(OCA R.Exc. at 10).

MEIUG/PICA state:

The Companies have an obligation to meet their POLR rate caps, as agreed to in the Settlement, and this obligation was confirmed in *ARIPPA*. The Companies entered into a Restructuring Settlement that brought rate stability to their customers during the transition from regulated rates to a competitive market; however, this rate stabilization came at a high price to consumers through the payment of billions of dollars of stranded costs. Not surprisingly, the Companies now seek to revise the portions of the Restructuring Settlement with which Met-Ed and Penelec are no longer satisfied; however, the Companies do not offer to provide any corresponding relief to customers. In fact, the Companies seek to increase the stranded costs to be collected, thereby compounding the detrimental effects that such a proposal would have on ratepayers, in addition to completely defying the intent of the signatories to the Settlement. Modifying the Settlement merely because the Companies are no longer satisfied with the "benefit" of their "bargain" would be contrary to the public interest, and the ALJs reasonably rejected this request.

(MEIUG/PICA R.Exc. at 8). (Citations omitted).

PPL makes an argument similar to that advanced by MEIUG/PICA. (PPL R.Exc. at 12). Citizen Power responds that the fact that the Companies were unable to justify an exception to the rate cap under terms they agreed to is not a reason to modify

the Settlement Agreement. “Doing so would allow Met-Ed and Penelec to perform an end-run around the terms they agreed to, and would endorse just the type of ‘heads I win, tails you lose’ construct” which was disallowed in *ARIPPA*. (Citizen Power R.Exc. at 12).

The Companies’ third argument in Exception No. 6 is that the ALJs expanded *ARIPPA* and improperly reached issues not encompassed in that decision. PPL responds that the essential point of the *ARIPPA* decision was the Court’s discussion of the meaning of Section 2804(4)(iii)(D)’s standard of price increases beyond the control of the utility. PPL asserts that the ALJs were correct that the Companies’ divestiture of generation assets together with their “subsequent decision to enter into a short-term, terminable, partial requirements contract with their affiliate thereafter, were wholly within their control.” It is that decision which resulted in the Companies’ current situation regardless of whether or not *ARIPPA* determined that divestiture was a bad business decision. (PPL R.Exc. at 14).

The OSBA asserts that the Companies’ assertion here is a mis-statement of the Recommended Decision. According to the OSBA, the ALJs did not conclude that *ARIPPA* found that divestiture was a bad business decision. The ALJs properly found that *ARIPPA* stands for the proposition that divestiture followed by a failure to secure supply contracts to protect the Companies’ POLR obligation does not constitute a circumstance beyond the Companies’ control. (OSBA R.Exc. at 6). OCA makes a similar argument. (OCA R.Exc. at 10-12).

In response to the Companies’ Exception No. 7 (relating to FirstEnergy’s acknowledgement of the Companies’ POLR obligations and the separate corporate identities of the Companies and FirstEnergy), MEIUG/PICA states:

Interestingly, FE has been more than willing to utilize the Companies in order to maximize profit and only now seeks to “separate” these affiliates when more profitable alternatives are available. R.D. at 49. For example, the FES Agreement was favorable for FE shareholders when the average market cost of power fell below rate cap levels in 2003, as compared to if FES sold this generation into the wholesale market. Once market prices rose above the rate cap, providing POLR supply was not as profitable for FES (and FE), and FES cancelled the Agreement. Considering the benefits FE has reaped from this Agreement, the ALJs’ finding that the Companies (including any affiliates and parent) must shoulder the outcome of these decisions, rather than to foist these burdens on to ratepayers, is not unreasonable.

(MEIUG/PICA R.Exc. at 10-11).

OCA responds that FirstEnergy merged with the Companies with full awareness of the Companies’ POLR obligation. In addition, OCA argues that the ALJs have placed no obligation on FES, the generation affiliate. However, the Commission does have the authority to disallow claims that it finds “unreasonable in light of the alternatives and actions that were available to the Companies.” (OCA R.Exc. at 13). OCA also points out that the financial condition of FirstEnergy was directly placed in issue by the Companies in their argument that the FES Agreement constituted a “subsidy” which could not be sustained and actually harmed FirstEnergy and its shareholders. Having made the argument, the Companies cannot now claim that the ALJs erred by examining the evidence on that issue; an issue raised by the Companies. *Id.* OCA also asserts that the ALJs were correct in noting that FirstEnergy extended its Ohio POLR commitment *after* the merger and with full knowledge of the Companies’ Pennsylvania POLR commitment. According to OSA, this means that FirstEnergy is treating its Ohio affiliates differently than its Pennsylvania affiliates. Accordingly, the Companies’ position that FirstEnergy generation was not sufficient to provide the Companies’ POLR supply “rings particularly hollow.” (OCA R.Exc. at 13-14).

PPL also responds to the Companies' Exception No. 7. PPL asserts that whether or not FirstEnergy agreed to support the Companies' POLR obligation in the merger proceeding is irrelevant to the issue presented here. PPL states: "Simply put, the basis of the ALJs' recommended decision is that the increases in the price of purchased power facing Met-Ed and Penelec were not beyond their control. What First Energy promised to do (or did not promise to do) does not alter the answer to this question." (PPL R.Exc. at 14).

The Companies' Exception No. 8 argues that the record supports a finding that the Companies did take steps to protect customers and "pursued all reasonable and prudent actions to procure POLR supply." (Companies Exc. at 18). The Companies assert that their efforts resulted in several long term contracts which will provide benefits to their customers through the POLR obligation. However, "additional such contracts were *simply not available* in the market." *Id.* The Companies conclude that "the evidence demonstrates that there was essentially nothing more MEPN could have done to 'protect' customers." (*Id.* at 19).

PPL responds to this Exception and argues that the Companies made a business decision to split their load into base load and peaking components. Once that decision was made, the Companies secured long-term contracts for the base load portion of their POLR responsibility. However, they "chose to rely on a short-term, terminable supply contract with their unregulated affiliate [FES] for the peaking portion of their POLR supply requirements." (PPL R.Exc. at 6). The termination of the FES peaking contract is the "undisputed cause of the increase in energy costs facing the Companies and the undisputed cause of the generation rate increases requested in this proceeding. (Tr. 598-599)." *Id.*

PPL argues further that while a full requirements contract may have been more expensive than the split base load and peaking arrangement, it would have

eliminated the need to seek a generation rate increase now. In addition, PPL asserts that any “savings” which the Companies assign to their business strategy is a myth because the customers were paying rates set in the Restructuring Settlement. Any difference between the base load contract and rates was retained by the Companies. Again, the Companies pursued a procurement strategy in their interest, the strategy was less than optimum from their perspective and they now ask the customers to support their failed strategy. (PPL R.Exc. at 7). Additionally, while a peaking supply contract may have been more difficult to procure at the time the FES Agreement was terminated, a full requirements contract would have been more readily available as that transaction is far more attractive to suppliers. (*Id.* 7-8).

OCA replies to the Companies’ Exception No. 8 and asserts that the ALJs properly found that the Companies pursued a strategy of relying on customers as a backstop for their costs. “The ALJs properly identified the self-inflicted problems that the Companies have created through their POLR procurement policies and the Recommended Decision should be adopted on these issues.” (OCA R.Exc. at 15). MEIUG/PICA make a similar argument noting that the FES Agreement protected the Companies’ unregulated affiliate rather than customers since FES was free to terminate the agreement when market prices rose above the rate cap. MEIUG/PICA argues that arrangement was hardly outside of the control of the Companies. MEIUG/PICA notes that such a termination provision was not found in any of the Companies’ other POLR supply arrangements. (MEIUG/PICA R.Exc. at 11).

Citizen Power responds that the test under *ARIPPA* is “whether the increased purchase power costs were ‘the results of business decisions,’ regardless of whether the decisions were prudent.” (Citizen Power R.Exc. at 15). According to Citizen Power, “[t]he power purchasing strategies of the Companies were exclusively within their control, and it was these strategies, whether deemed prudent or not, that have left them exposed to POLR supply costs without adequate hedges.” *Id.*

In their Exception No. 9, the Companies assert that the ALJs incorrectly determined that their corporate officers acted in a fashion that benefited shareholders to the detriment of ratepayers. The Companies also argue that their corporate officers acted at all times in a fashion consistent with their fiduciary duties. The Companies argue that all corporate officers owe a fiduciary duty to shareholders. However, the Companies gave due consideration customer interests. (Companies Exc. at 19-21).

OTS responds that the Companies' corporate officers failed to "operate in the best interests of Met-Ed and Penelec." (OTS R.Exc. at 7). OTS argues that "corporate decisions were apparently made exclusively to increase FirstEnergy shareholder value and not made based upon what is in the best interest of the operating utility." *Id.* Similarly, OCA argues that FirstEnergy's corporate leaders were entering into short-term cancellable contracts on behalf of the Companies with their affiliate. OCA then asserts that FirstEnergy made "a calculated decision to terminate the supply arrangement (FES Agreement) to gain additional profits for its unregulated affiliate." (OCA R.Exc. at 15-16). OCA concludes that the Companies' claim of price spikes due to the cancellation of the FES Agreement "is a self-inflicted wound that is designed to increase the profits of FirstEnergy's unregulated affiliates at the expense of Met-Ed and Penelec's customers." (*Id.* at 16). MEIUG/PICA makes a similar argument. (MEIUG/PICA R.Exc. at 10).

PPL responds to this Exception and states:

Analysis of the fiduciary obligations of officers of the various companies does not change the fact that Met-Ed and Penelec choose [sic] to enter into a short-term, terminable partial requirements contract with its affiliate, and the affiliate is now terminating the agreement, an act which exposes Met-Ed and Penelec to increases in the price of purchased power, and which was completely within their control.

(PPL R.Exc. at 16).

The Companies argue in Exception No. 10 that the ALJs erred when they determined that the Companies were in the same position as other EDCs in the Commonwealth which are operating under rate caps with POLR obligations. The Companies argue that no other EDC had a provision like their CDS plan; that their divestiture of generation was unique since they sold their plants to third parties; and, that to the extent they now have affiliate-owned generation, that is insufficient to supply their entire POLR needs. (Companies Exc. at 21-22).

OCA responds that the Companies are “in essentially the same position as the other Pennsylvania restructured utilities who have honored their rate caps. As the ALJs stated in the Recommended Decision, ‘Other Pennsylvania EDCs have met their obligations under their Restructuring Settlements, despite the likelihood that greater profits could be realized if they did not continue to meet their obligation.’” (OCA R.Exc. at 16, quoting the R.D. at 67). PPL responds that “the Companies explain, in some detail, the differences between PPL Electric and their own Restructuring Settlements (Met-Ed Penelec Exceptions, at 21-22), but they do not and cannot explain why they needlessly exposed their customers to substantial price risk by failing to obtain a long-term full requirements contract.” (PPL R.Exc. at 8).

MEIUG/PICA argue that whatever differences the Companies purport to show, those differences are immaterial to the issue of whether they should receive an exception to the rate cap. MEIUG/PICA assert that “nothing in the profile of the Companies prohibited Met-Ed and Penelec from meeting their POLR obligations, as has been done by all other EDCs, except for the Companies’ business decisions, which sought to maximize profits.” (MEIUG/PICA R.Exc. at 12).

OSBA responded to Constellation’s Exception No. 1 and recommended rejection of that argument. OSBA posits that Constellation’s position would result in an

increase in rates over and above what the Companies have requested. In addition, OSBA argues that Constellation has failed to present evidence necessary to support a finding on what the “market prices” would be in order to establish a basis upon which to align the proposed rates. (OSBA R.Exc. at 16). OSBA also comments that Constellation is actually seeking to “turn this proceeding into a post-cap POLR case, not the rate-cap exception case that it is.” *Id.*

D. Disposition

The Companies Exception No. 6 is a two-pronged argument which first claims that the Restructuring Settlement provides for an exception to the rate cap in addition to that found in Section 2804(4)(iii)(D) of the Code. Second, even if there is no explicit additional exception in the Restructuring Settlement, the Companies argue that the circumstances are such that we should reconsider our Order approving the Settlement and create one under Section 703 of the Code, 66 Pa. C.S. § 703). Neither of these arguments is persuasive.

We have reviewed the Restructuring Settlement in the context of the Companies’ arguments that the failure of the CDS provisions provides them with an alternative exception to the rate cap. Two particular provisions are of interest. First, ¶ F.3 of the Restructuring Settlement provides that “[r]egardless of whether PLR service is provided by GPUE or a competitive PLR supplier, all retail PLR service shall be subject to the applicable generation rate caps.” Second, ¶ F.9 provides that if there are no qualified bids for CDS service, the Companies will provide PLR service at the rate cap levels unless the Companies file a petition with the Commission and receive approval to exceed the rate caps. ¶ F.9 provides no standard under which such a petition would be adjudicated, but it does provide a time limit (90 days). However, Section 2804(4)(iii)(D) does provide such a standard. We agree with the ALJs that ¶ F.9 provides the process by

which the Companies could have petitioned for an exception to the rate caps, but that Section 2804(4)(iii)(D) of the Code provides the standard.

We also agree with the ALJs that there is nothing in the record that would persuade us to exercise our discretion to reconsider the Restructuring Settlement and provide for a rate cap exception independent of the Code. As stated by Citizen Power, to provide such an alternative exception at this point “would allow Met-Ed and Penelec to perform an end-run around the terms they agreed to, and would endorse just the type of ‘heads I win, tails you lose’ construct” which was disallowed in *ARIPPA*. (Citizen Power Exc. at 12). MEIUG/PICA also note that the rate caps were part of the over-all agreement struck in the Restructuring Settlement which included “the payment of billions of dollars of stranded costs.” (MEIUG/PICA Exc. at 8). We find nothing in the record before us which would persuade us to adjust that negotiated balance independent of the standards set forth in Section 2804(4)(iii)(D) of the Code. The Companies’ Exception No. 6 is denied.

In Exception No. 7, the Companies’ argue that the ALJs erred when they appeared to find that FirstEnergy agreed to take on the POLR obligation of the Companies. The Companies also argue that the ALJs ignored the distinction between the Companies and FirstEnergy’s unregulated affiliates. There is simply no merit to this Exception and we will deny it. In addition, the Companies argue in Exception No. 8 that they took all prudent steps to properly manage their supply portfolio. We will deny that Exception as well.

The ALJs’ entire discussion of the Companies’ relationship with FirstEnergy and FirstEnergy’s unregulated affiliates centered around the Companies’ contractual relationships with FES and FirstEnergy’s knowledge of the Companies’ POLR obligations at the time of the merger. This discussion was in the context of Section 2804(4)(iii)(D)’s standards for an exception to the rate cap and whether the

Companies' POLR supply acquisitions were properly structured so that the rise in the current prices for supply could be found to be outside of the control of the Companies. The ALJs did find that the Companies entered into an agreement with one of FirstEnergy's unregulated affiliates (FES) that provided for early termination and left the Companies exposed to a rising market. That procurement strategy is remarkably similar to the strategy that the *ARIPPA* court found to be in the Companies' control.

The Companies argue that no long term contracts were available at attractive rates similar to the FES Agreement. However, PPL points out that the FES Agreement was for peaking energy and was not a full requirements contract such as would have been attractive to an alternative supplier. (PPL R.Exc. at 7-8). The termination of the FES Agreement is the reason the Companies are facing increased energy costs now. The strategy of the Companies to split their POLR supply acquisition into base load and peaking components was within their discretion as was the decision to enter into the FES Agreement with its termination provisions.

Whether or not FirstEnergy agreed to support the Companies' POLR obligations, the fact is that the Companies' POLR supply portfolio was managed in such a fashion that left them exposed to a rising market. The Companies' arguments regarding the availability of long-term contracts are unconvincing given the manner in which they structured their portfolio. We are also mindful of the fact that the FES Agreement provided FES with above market prices for a period of time. It is not surprising that FES terminated the Agreement in accordance with its terms when the market price rose. That circumstance was within the Companies' control and a direct result of their business strategy. Thus, in accordance with Section 2804(4)(iii)(D) of the Code, and consistent with *ARIPPA*, we will deny Exception Nos. 7 and 8.

In Exception No. 9, the Companies argue that the ALJs erred in their discussion of the role of certain corporate officials in the FES contract. In Exception No.

10, the Companies argue that the ALJs erred when they found that the Companies are similarly situated as other Pennsylvania EDCs who are required to provide POLR service under rate caps. We find that both of these issues have little relevance to the standards for a rate cap exception under Section 2804(4)(iii)(D) of the Code and *ARIPPA*. Regardless of the ALJs' discussion on these points, the fact is that the decision to enter into a short-term, terminable partial requirements contract with an affiliate was within the Companies' control. It is the termination of that contract which exposes the Companies to the current market prices. Accordingly, we will deny Exception Nos. 9 and 10.

V. TRANSMISSION SERVICE CHARGE RIDER

The Companies' transmission rate caps have expired and the Companies' proposed removing transmission costs from base rates and establishing a reconcilable Transmission Service Charge (TSC) Rider. The proposed TSC Rider was designed to include all transmission service-related costs incurred to meet the Companies' POLR obligations. (R.D. at 69). The specific costs to be included in the TSC Rider as proposed by the Companies are:

- (i) network integration transmission service (NITS) costs and FERC-approved PJM transmission congestion charges; (ii) FERC-approved transmission-related ancillary and administrative costs incurred and administered by PJM; (iii) "Other" costs similar to those in (i) and (ii) that may arise in the future, as approved by FERC and charged under the PJM Open Access Transmission Tariff (OATT); and (iv) transmission risk management costs incurred to mitigate risks associated with transmission-related costs.

(R.D. at 71).

The ALJs stated that there was no dispute regarding the level of any of the costs as proposed by the Companies. In addition, there was no dispute regarding

inclusion of any of the costs proposed in the Companies' Exhibit MRH-1, except for congestion and related risk management costs. (R.D. at 71).

The Companies also proposed to include previously deferred 2006 transmission costs in the TSC rider. (R.D. at 74). This was opposed by several Parties. We will first review the issue surrounding the inclusion of congestion costs in the TSC Rider. Then we will move to consideration of the inclusion of the deferred 2006 transmission costs.

A. Inclusion of Congestion Costs in the TSC Rider

1. Positions of the Parties

The Companies must obtain transmission services from PJM Interconnection, LLC (PJM), in order to deliver generation to their POLR customers. In the Companies' view, those transmission services generate the costs as set forth in our quote of the ALJs above. For the most part, the costs are imposed by PJM in accordance with the FERC approved OATT. The Companies propose to collect those costs through the TSC Rider. (R.D. at 71).

Those costs that are challenged in this proceeding come under the category of "congestion costs" and related risk management costs. These costs come into play when there is congestion on the transmission system which affects delivery of power to the Companies' POLR customers. "Transmission congestion occurs when the amount of electricity flowing over certain portions of the transmission grid nears the capacity of those same points on the grid." (R.D. at 71).

The Companies asserted that congestion costs and related risk management costs are tied to transmission congestion and are properly included in the TSC Rider. The Companies pointed out that FERC has adopted a final rule which will offer transmission

rate incentives to reduce transmission congestion in *Promoting Transmission Investment Through Pricing Reform*, Docket No. RM06-4-000 (Order No. 679 issued July 20, 2006), 116 FERC ¶ 61,057 (July 20, 2006). This rule was adopted pursuant to Section 219 of the Federal Power Act, 16 U.S.C. § 824s, a new provision added by the Energy Policy Act of 2005. In addition, it was noted that PJM recently authorized construction of \$1.3 billion in electric transmission upgrades in order to ensure continued grid reliability and reduce congestion costs. (R.D. at 72).

The Companies asserted that the foregoing demonstrates “the direct correlation between the state of the transmission system and the level of congestion costs.” (R.D. at 72). The Companies also asserted that the Energy Policy Act of 2005 and FERC’s action in *Promoting Transmission Investment* both reveal that Congress and the FERC intend that transmission congestion should be dealt with through new transmission facilities, not generation facilities. Also according to the Companies, no Party challenges inclusion of NITS-type capital expenditures in the TSC Rider. Given that circumstance, the Companies argue that proper matching of the costs associated with improving the transmission system with the benefit of reducing congestion costs indicates that both types of costs should be included in the same cost category – transmission. *Id.*

OCA, MEIUG/PICA, Constellation and the Commercial Group all argued that congestion costs and related risk management costs are more properly categorized as generation costs, not transmission costs. These Parties asserted that congestion charges reflect the differences in the cost of generation that result when the least cost available energy cannot be delivered to a constrained area and higher cost generation units in that area must be dispatched to serve load. (MEIKUG/PICA R.B. at 25-27). Accordingly, while the amount of congestion on the system never affects the price of transmission, it has a direct and immediate impact on the price of generation. *Id.* Constellation stated that “Congestion costs are not determined based on the transmission rate structure but are a function of energy prices (i.e. LMP) and that is why classifying them as transmission

costs is inappropriate.” (CNE St. 1S at 6). Constellation also noted that Financial Transaction Rights (FTR) and Auction Revenue Rights (ARR) revenues and FTR costs are a function of the amount of energy delivered and are more properly reflected as generation costs. (CNE St. 1S at 6).

OTS argued that the TSC should be rejected altogether. According to the OTS, there is insufficient Commission authority to properly review the annual reconciliation process. (R.D. at 70).

2. ALJs’ Recommendation

The ALJs recommended adoption of the TSC Rider. They found that the Companies had met their burden of proof and that the TSC mechanism is a just and reasonable method to recover those costs. They found that contrary to OTS’ position, Section 1307(e) of the Code, 66 Pa. C.S. § 1307(e), provided sufficient authority for the Commission to oversee the reconciliation process. The ALJs noted that the proposed TSC Rider is similar to that recently approved by the Commission in *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-00049255 (Order entered December 2, 2004). (R.D. at 70).

The ALJs also recommended that congestion costs, including transmission risk management costs, be treated as transmission costs and should be reflected in the TSC Rider. The ALJs found that the opposing Parties confused the measurement of congestion costs (based upon generation prices) with the existence of congestion on the transmission system. According to the ALJs, if there were no congestion on the transmission system, there would be no congestion costs and no need to acquire risk management tools such as FTRs and ARRs. Similarly, the ALJs found that Contracts for Differences (CFD) costs are like ARRs and FTRs and should be contained in the TSC Rider. (R.D. at 72-73).

The ALJs stated that the Companies modified their initial proposal so as to allocate costs on a demand and energy basis and they recommended adoption of this methodology. (R.D. at 70). The transmission and related ancillary service costs were estimated to be \$156.6 million for ME and \$81.7 million for PN in 2006. The TSC Rider would commence in January, 2007.

3. Exceptions

In OTS' Exception No. 4, OTS recommends rejection of the TSC Rider. OTS argues that the TSC proposal does not provide for a prudence review and should be rejected. OTS asserts that the review available under Section 1307(e) of the Code, 66 Pa. C.S. § 1307(e), does not provide for the proper scope of review for a reconcilable charge. Accordingly, OTS recommends that the TSC should be rejected. (OTS Exc. at 8).

MEIUG/PICA filed Exception No. 1 to the ALJs' recommendation. MEIUG/PICA argue that the nature and purpose of congestion and congestion related expenses reveal a clear connection to generation. MEIUG/PICA assert that the ALJs' recommendation is "counterintuitive" to the extent they find that MEIUG/PICA confuse measurement of congestion costs with the existence of congestion on the transmission system. They argue that congestion on the transmission system results in higher generation costs via LMP. There is never an impact on transmission costs. (MEIUG/PICA Exc. at 3). In addition, MIEUG/PICA argue that the connection of these costs to generation should prevent their inclusion in the TSC Rider because that would permit the Companies to sidestep the generation rate caps.

MEIUG/PICA argue further that inclusion of congestion costs in the TSC Rider could have the result of double collection. Recalling that congestion will result in a higher LMP, any ratepayer electing real-time or day-ahead LMP service from the

Companies as the POLR provider will pay for the cost of congestion twice, once under the TSC Rider and once in the LMP. (MEIUG/PICA Exc. at 5).

MEIUG/PICA also assert that congestion risk management tools are generation related. They point out that FTRs operate as a hedge against paying the higher price of generation during congestion periods. FTRs are not held as guarantees that power will be delivered, they are held to hedge against the risk of higher generation charges. “Because FTRs entitle the Companies to recover the difference in the price of *generation* due to congestion, it is clearly a generation-related expense.” (MEIUG/PICA Exc. at 5). MEIUG/PICA argue further that ARR follows load in order to maximize the benefits of retail competition. But if ARRs are attached to the transmission system, that could potentially require two separate TSC Riders; one for shopping customers and one for POLR customers in order to accommodate shifts of ARRs with load. “This result would be both confusing to customers and administratively burdensome.” (*Id.* at 6).

Constellation asserted error in its Exception No. 2. According to Constellation, the ALJs erred in two ways. Constellation asserts that the ALJs erred when they found that the Parties in opposition confused the measurement of congestion with the existence of congestion on the transmission system. This error was said to be caused by the manner in which the ALJs defined congestion. According to Constellation, the ALJs characterized congestion as the result of constraints on the transmission system. However, Constellation argues that the FERC defines congestion differently:

Congestion is defined as the inability to inject and withdraw additional energy at particular locations in the network due to the fact that the injections and withdrawals would cause power flows over a specific transmission facility to violate the reliability limits for that facility. The market operator manages congestion by scheduling and dispatching generators that can meet load in the presence of congestion. Financially, in LMP markets the price of congestion is measured as the

difference in the cost of energy at two different locations in the network.

(Constellation Exc. at 8-9, quoting *Long Term Firm Transmission Rights in Organized Electricity Markets*, FERC Docket no. RM06-8-001; Order No. 681-A (Issued November 16, 2006), at ¶ 7).

Constellation argues that the foregoing indicates that FERC has “confirmed that the existence of congestion is tied to the injection and withdrawal of the energy commodity,” (Constellation Exc. at 9). Accordingly, Constellation concludes that congestion is a cost of supplying and using energy and is generation-related. *Id.* Constellation also asserts that recognition of these costs as generation related is necessary for the development of the competitive market. EGSs incur these costs as a cost of supplying generation and must pass them on to shopping customers. Constellation argues that unless these costs are deemed part of generation, POLR customers will pay the costs twice, once to the Companies and again to their EGS. *Id.*

OCA filed its Exception No. 12 to the inclusion of congestion costs, FTRs and ARR in the TSC Rider. OCA asserts that because congestion costs are determined by generation prices and are unrelated to the transmission rate structure, they are generation related. (OCA Exc. at 32). With regard to costs that are not billed by PJM, those costs are said to be in the Companies’ direct control and “have no place in the TSC.” *Id.*

The Companies respond to each of the Exceptions noted above. With regard to OTS’ argument regarding oversight, the Companies assert that Section 1307(e) of the Code mandates a public hearing on the annual reconciliation and any matters pertaining to the TSC Rider. In addition, the Companies assert that OTS ignores the FERC role in reviewing and approving transmission costs. (Companies R.Exc. at 5).

The Companies respond to those Parties opposed to including congestion costs and congestion risk management in the TSC Rider and argue that the ALJs correctly determined that they are transmission costs, not generation. The Companies reiterate that the issue is not whether the costs are measured by generation or transmission, but that the costs arise because of the state of the transmission system. (Companies R.Exc. at 9). The Companies also respond to Constellation’s argument regarding double payments and the impact on competition. According to the Companies, both generation and transmission rates are by-passable by shopping customers. That includes the TSC Rider. (*Id.* at 7).

4. Disposition

Most of the Parties have agreed that a TSC is an appropriate mechanism for the Companies to recover transmission costs. OTS objected to the TSC on the basis that there is no prudency oversight under Section 1307(e) of the Code which is necessary for a reconcilable charge such as the TSC. We will deny OTS’ Exception No. 4. We agree with the ALJs and the Companies that Section 1307(e) provides more than sufficient oversight. Specifically, Section 1307(e)(2) provides that the Commission will hold an annual hearing on the TSC “and any matters pertaining to the use . . . of such automatic adjustment clause in the preceding period and may include the present and subsequent periods.” We find that Section 1307(e) provides this Commission with sufficient oversight authority.

Several Parties filed Exceptions to the ALJs’ inclusion of congestion charges in the TSC. We will deny these Exceptions (MEIUG/PICA Exc. No. 1; Constellation Exc. No. 2; OCA Exc. No. 12). On this issue, we agree with the ALJs that the congestion charges are the result of transmission constraints and are properly included in the TSC. Constellation argues that the FERC definition is at odds with this finding because it speaks in terms of injection and withdrawal of generation. However, that definition centers on the fact that withdrawals and injections of generation become a problem when they “would cause *power flows over a specific transmission facility to violate the reliability limits for that facility.*” *Long Term Firm Transmission Rights in Organized Electricity Markets*. (Emphasis added). Thus, it is the

transmission system which creates the potential for congestion and triggers the need for risk management tools that result in congestion charges. As the ALJs stated, “if there is no constraint on the transmission system, there are no congestion costs, regardless of the generating stations’ location or dispatch order.” We agree.

In addition to the foregoing, we note the definition of transmission and distribution costs contained in Section 2803 of the Code, 66 Pa. C.S. § 2803: “All costs directly or indirectly incurred to provide transmission and distribution services to retail customers. This includes the return of and return on capital investments necessary to provide transmission and distribution services and associated operating expenses, including applicable taxes.” Clearly, the congestion costs at issue here are costs incurred to provide transmission services to retail customers. The FERC has approved inclusion of almost all of these charges in PJM’s Open Access Transmission Tariff as transmission related charges. The Code’s broad definition quoted here and FERC’s treatment of their recovery as transmission related charges support our finding that the charges are properly recovered as transmission charges in the TSC.

B. Deferred 2006 Transmission Charges

In *Petition of Metropolitan Edison Company and Pennsylvania Electric Company for Authority to Modify Certain Accounting Procedures*, Docket No. P-00052143 (Order entered May 5, 2006) (Deferral Order), the Commission granted the Companies’ request to defer for accounting and financial reporting purposes certain incremental FERC-approved transmission charges. When the Commission granted the Companies’ request, it specifically stated that authorization for the deferral was not an assurance of future rate recovery, that the Companies were to claim the deferred costs at the first available opportunity, and that any party to a rate case was entitled to oppose the claim. (R.D. at 74).

1. Parties' Positions

The Companies propose to recover their deferred 2006 transmission costs over a ten year period with interest. The carrying charges will be calculated at the Companies' cost of long term debt as approved in the Deferral Order. The deferral period commenced January 1, 2006. Accordingly, the future test year (calendar 2006) encompasses twelve months of the deferral period. The Companies' original deferral request was for both 2005 and 2006 costs. That was modified in this proceeding to encompass only the 2006 costs. (R.D. at 75).

The Companies argued that the deferred costs were new costs created by the expansion of PJM and could not have been projected in the Companies' previous rate proceedings. In addition, the Companies asserted that the costs were extraordinary and, since the rates proposed in this proceeding will not go into effect until 2007, these costs will not be recovered absent approval in this proceeding. Finally the Companies asserted that they acted promptly to recover the costs when they became known, first through the request for deferral and then by inclusion in their first rate proceeding through the TSC Rider. The foregoing is said to meet the test of *Popowsky v. Pa. PUC*, 868 A.2d 606 (Pa. Cmwlth. 2004) (*Popowsky*). (R.D. at 75-76).

OSBA argued that the failure of the Companies to recover their 2006 transmission costs is entirely of their own making. OSBA points out that the Companies' transmission rate caps expired on December 31, 2004. The Companies had every opportunity to seek a transmission rate adjustment effective for 2005. Had they done so, there would not have been unrecovered transmission expenses. Instead, the Companies sought deferred accounting treatment. As such, the problem of recovery is one brought on the Companies by their own actions. OSBA asserted that denial of the requested recovery would reduce the Companies' combined TSC revenue requirement from \$230 million to \$203.3 million. (OSBA M.B. at 25).

OCA argued that approval of the deferred costs would constitute improper single-issue ratemaking because the Companies are seeking recovery of one element of their total operations without considering other elements “for example, the Companies’ excess distribution revenues.” (OCA M.B. at 84, quoting OCA St. 3 at 23). The OCA further argued that the only exception to the prohibition against single item ratemaking requires a finding that the item is extraordinary, non-recurring and volatile, citing *Pennsylvania Electric Company v. Pa. PUC*, 502 A.2d 722 (Pa. Cmwlth. 1983). OCA asserted that none of the three requirements have been met. OCA asserted that the costs involved are normal costs of providing service, the costs have been relatively consistent from year to year and they occur every year, and the Companies failed to pursue the costs through a rate proceeding at their earliest opportunity. OCA argued that the only costs which could be deemed volatile were the congestion costs, which OCA asserted were generation costs, not transmission costs. (*Id.* at 85). OCA also argued that if recovery is permitted, congestion costs should be removed and there should be no carrying charges on the amortized amount. OCA asserted that rejection of carrying charges is consistent with the Commission’s policy of not allowing a return on a cost at the same time it is being amortized and recovered in rates. (OCA M.B. at 85-86).

MEIUG/PICA also opposed recovery of the deferred 2006 transmission costs. Like OCA, MEIUG/PICA argued that the costs failed to meet the test that they be extraordinary, unanticipated and non-recurring, citing *Popowsky*. (MEIUG/PICA M.B. at 50). MEIUG/PICA advanced arguments similar to those made by OCA described above. (*Id.* at 50-51).

2. ALJs' Recommendation

The ALJs recommended approval of the request to recover the deferred 2006 transmission expenses. The ALJs found that the costs met the test set forth in *Popowsky*. The ALJs described that test as follows:

The analysis includes: (1) “whether the costs arise from an inaccurate projection in a prior proceeding”, which includes a consideration of “whether the costs were anticipated and whether they were imposed on the utility from the outside”; (2) “the extraordinary nature of the costs”, including “whether the expenses themselves are extraordinary and nonrecurring”, “whether the triggering event was an unanticipated, extraordinary, one-time event”, and “whether the expenses are legitimate operating expenses which, if recovery is denied on the grounds that rate recognition would be retroactive, will never be recovered”; and (3) “whether the utility claimed the expenses at the first reasonable opportunity”, which includes a consideration of “whether the utility acts as though the expenses are something it can absorb with its current revenue under its existing tariff.”

(R.D. at 75, quoting *Popowsky*, 868 A.2d at 611).

The ALJs determined that each of the three tests had been met. They found that none of the costs could have been anticipated in the Companies' prior proceedings and, except for the CFD which have been deemed transmission, the costs have been imposed on the Companies by the FERC approved PJM OATT. That was said to satisfy the first test. Second, the ALJs found that the costs were extraordinary as they were substantial. The ALJs noted that net congestion costs alone escalated by 450% from 2004 to 2006. Also, given the Deferral Order and the fact that the proposed rates are to be effective in 2007, these costs will not be recovered absent approval in this case. This was found to satisfy the second test. Finally, the ALJs found that the Companies acted quickly noting that they immediately filed for deferral when the costs became clear and they are only seeking recovery of the costs for 2006. As such, they acted at the first

opportunity and did not act as though the deferred costs were something that could be absorbed. Accordingly, the ALJs recommended a finding that the deferred 2006 transmission costs met the test in *Popowsky* for an exception to the prohibition against single issue ratemaking. (R.D. at 75-76). The ALJs also recommended approval of carrying charges “due to the magnitude of the charges to be recovered (exceeding \$200 million) and the length of time over which the charges will be amortized (ten years, beginning in 2007),” (R.D. at 77).

3. Exceptions

In OSBA’s Exception No. 1, OSBA argues that the ALJs erred by finding that the deferred 2006 transmission costs met the *Popowsky* test. OSBA argues that the ALJs failed to consider whether the costs were anticipated by the Companies. OSBA asserts that the Companies acted to request deferral treatment ten days after the end of their transmission rate caps. Accordingly, they clearly anticipated the imposition of these costs. Because the Companies anticipated imposition of the costs, it was error for the ALJs to find that the first prong of *Popowsky* was satisfied. OSBA also argues that “the expansion of PJM (with an associated increase in transmission costs due to an increase in congestion) was not an unanticipated, extraordinary, one-time event. These transmission costs are, in fact, usual and ordinary costs of doing business.” (OSBA Exc. at 7). Also, OSBA argues that the Companies did not act at their first reasonable opportunity. Rather than seek rate relief, the Companies pursued a deferral. They did not seek recovery of the costs when they were incurred. OSBA argues that “for all of 2005, the Companies behaved as if they could absorb these costs under the existing tariff.” (OSBA Exc. at 9). Accordingly, OSBA argues that the *Popowsky* test has not been met and the claim must be rejected.

In its Exception No. 2, OSBA also asserts error in the ALJs’ recommendation to approve carrying charges on the deferred costs. First, the Companies

could have avoided the deferral by seeking timely recovery in a rate proceeding. Thus, the problem is of the Companies own making and ratepayers should not be made to pay carrying charges resulting from the Companies' decision to defer recovery. Second, OSBA asserts that over the ten year period, it is likely that ratepayers who were not customers when the charges were incurred will be forced to pay them. Finally, the Commission should not encourage delayed recovery of transmission expenses by approving carrying charges, particularly when the Companies could have acted much earlier. (OSBA Exc. at 9-11).

OSBA also filed its Exception No. 3 which claims error in the ALJs' failure to clarify whether the amortization of 2006 transmission costs would be by-passable by shopping customers. OSBA argues that these costs should not be by-passable since customers who received transmission services from the Companies in 2006 bear cost-causation responsibility for the charges. If any of those customers move to an EGS during the amortization period, they will avoid payment of costs incurred on their behalf. This, in turn, will result in fewer customers paying the costs. (OSBA Exc. at 12).

OCA's Exception No. 11 (OCA Exc. at 28-31) and MEIUG/PICA's Exception No. 2 (MEIUG/PICA Exc. at 7-9) make the same arguments stated in OSBA's Exception No. 1. OCA also claims error in the ALJs' recommended approval of carrying charges. OCA argues that approval violates "the Commission's established policy of not allowing a return on a cost at the same time it is being amortized and recovered in rates." (OCA Exc. at 30).

The Companies respond to OSBA, OCA and MEIUG/PICA and assert that the ALJs' analysis of *Popowsky* and the application of *Popowsky* to the facts here are correct. (Companies R.Exc. at 10-11). The Companies also respond to OCA and OSBA's opposition to carrying charges. The Companies argue that they are not seeking

to include the 2006 costs in rate base. In addition, the magnitude of the costs and the length of the amortization period support the request for carrying charges.

4. Disposition

We agree with the ALJs' recommendation to approve the Companies' request to recover the deferred 2006 transmission expenses. The ALJs properly analyzed the request under the standards set forth in *Popowsky* and found that the record supported approval of the recovery. For the reasons set forth at Pages 74 through 77 of the Recommended Decision, we will adopt the ALJs' recommendation. Accordingly, OSBA Exception No. 1, OCA Exception No. 11 and MEIUG/PICA's Exception No. 2 are denied.

We also agree with the ALJs' recommendation to approve carrying charges at the rate set forth in the Deferral Order. OCA and OSBA both excepted to this recommendation. We will deny these Exceptions. We agree with the Companies that the magnitude of the costs and the length of the amortization period provide adequate support for carrying charges. The ALJs' analysis of the *Popowsky* standards also rebuts most of the OSBA's arguments in OSBA's Exception No. 2.

In OSBA's Exception No. 3, it argues that the ALJs erred by failing to address the issue of whether the deferred transmission charge is by-passable by shopping customers. OSBA argues that customers who were transmission customers of the Companies in 2006 should not be able to by-pass the deferred charges. We find that it is by-passable. As noted by the Companies, the OSBA position is impractical and poor policy. For the reasons expressed in the Companies' Reply Exceptions at Pages 11-12, Note 8, we will deny OSBA's Exception No. 3.

VI. GENERAL PRINCIPLES FOR A 1308 GENERAL RATE INCREASE CASE

In deciding this, or any other, general rate increase case brought under Section 1308(d) of the Code, 66 Pa. C.S. § 101 *et seq.*, certain general principles always apply.

A public utility is entitled to an opportunity to earn a fair rate of return on the value of the property dedicated to public service. *Pennsylvania Gas and Water Co. v. Pa. PUC*, 341 A.2d 239 (Pa. Cmwlth. 1975). In determining a fair rate of return the Commission is guided by the criteria provided by the United States Supreme Court in the landmark cases of *Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). In *Bluefield*, the Court stated:

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

The burden of proof to establish the justness and reasonableness of every element of a public utility's rate increase request rests solely upon the public utility in all proceedings filed under Section 1308(d) of the Code. The standard to be met by the public utility is set forth at Section 315(a) of the Code, 66 Pa. C.S. § 315(a):

Reasonableness of rates. –In any proceeding upon the motion of the Commission, involving any proposed or existing rate of any public utility, or in any proceeding 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.

The Pennsylvania Commonwealth Court, in reviewing Section 315(a) of the Code, interpreted the utility's burden of proof in a rate proceeding as follows:

Section 315(a) of the Public Utility Code, 66 Pa. C.S. § 315(a), places the burden of proving the justness and reasonableness of a proposed rate hike squarely on the public utility. *It is well-established that the evidence adduced by a utility to meet this burden must be substantial.*

Lower Frederick Twp. Water Co. v. Pa. PUC, 48 Pa. Cmwlth. 222, 226-227, 409 A.2d 505, 507 (1980) (emphasis added). See also, *Brockway Glass Co. v. Pa. PUC*, 63 Pa. Cmwlth. 238, 437 A.2d 1067 (1981).

In general rate increase proceedings, it is well established that the burden of proof does not shift to parties challenging a requested rate increase. Rather, the utility's burden of establishing the justness and reasonableness of every component of its rate request is an affirmative one and that burden remains with the public utility throughout the course of the rate proceeding. It has been held that there is no similar burden placed on other parties to justify a proposed adjustment to the Company's filing. The Pennsylvania Supreme Court has held:

[T]he appellants did not have the burden of proving that the plant additions were improper, unnecessary or too costly; on the contrary, that burden is, by statute, on the utility to demonstrate the reasonable necessity and cost of the installations, and that is the burden which the utility patently failed to carry.

Berner v. Pa. PUC, 382 Pa. 622, 631, 116 A.2d 738, 744 (1955).

This does not mean, however, that in proving that its proposed rates are just and reasonable a public utility must affirmatively defend every claim it has made in its filing, even those which no other party has questioned. As the Pennsylvania Commonwealth Court has held:

While it is axiomatic that a utility has the burden of proving the justness and reasonableness of its proposed rates, it cannot be called upon to account for every action absent prior notice that such action is to be challenged.

Allegheny Center Assocs. v. Pa. PUC, 570 A.2d 149, 153 (Pa. Cmwlth. 1990) (citation omitted). See also, *Pa. PUC v. Equitable Gas Co.*, 73 Pa. P.U.C. 310, 359 – 360 (1990).

Additionally, the provisions of 66 Pa. C.S. § 315(a) cannot reasonably be read to place the burden of proof on the utility with respect to an issue the utility did not include in its general rate case filing and which, frequently, the utility would oppose. Inasmuch as the Legislature is not presumed to intend an absurd result in interpretation of its enactments¹⁰, the burden of proof must be on a party to a general rate increase case who proposes a rate increase beyond that sought by the utility.

The mere rejection of evidence contrary to that adduced by the public utility is not an impermissible shifting of the evidentiary burden. *United States Steel Corp. v. Pa. PUC*, 72 Pa. Cmwlth. 171, 456 A.2d 686 (1983).

In analyzing a proposed general rate increase, the Commission determines a rate of return to be applied to a rate base measured by the aggregate value of all the utility's property used and useful in the public service. The Commission determines a proper rate of

¹⁰ 1 Pa. C.S. § 1922(1), *PA Financial Responsibility Assigned Claims Plan v. English*, 541 Pa. 424, 64 A.2d 84 (1995).

return by calculating the utility's capital structure and the cost of the different types of capital during the period in issue. The Commission is granted wide discretion, because of its administrative expertise, in determining the cost of capital. *Equitable Gas Co. v. Pa. PUC*, 45 Pa. Cmwlth. 610, 405 A.2d 1055 (1979) (determination of cost of capital is basically a matter of judgment which should be left to the regulatory agency and not disturbed absent an abuse of discretion).

Any issue or Exception that we do not specifically address has been duly considered and will be denied without further discussion. It is well settled that we are not required to consider, expressly or at length, each contention or argument raised by the Parties. *Consolidated Rail Corporation v. Pennsylvania Public Utility Commission*, 625 A.2d 741 (Pa. Cmwlth. 1993); *see also, University of Pennsylvania v. Pennsylvania Public Utility Commission*, 485 A.2d 1217 (Pa. Cmwlth. 1984). "A voluminous record does not create, by its bulk alone, a multitude of real issues demanding individual attention" *Application of Midwestern Fidelity Corp.*, 26 Pa. Cmwlth. 211, 230 fn.6, 363 A.2d 892, 902, n. 6 (1976). With the foregoing principles in mind, we turn to the rate issues before us.

VII. RATE BASE/CASH WORKING CAPITAL

A. Distribution

Based on their lead/lag studies of revenues and expenses, ME claimed cash working capital of \$85,580,000 and PN claimed cash working capital of \$76,625,000. (R.D. at 81). There is disagreement among the Parties over the following issues: 1) Payment lag associated with Pennsylvania Corporate Net Income Tax (CNI) and Pennsylvania Capital Stock Tax (CS); 2) Treatment of certain so-called "non-cash" items; 3) Treatment of transmission costs; 4) Treatment of return on equity; 5) Payment lag associated with interest on long-term debt; and 6) Payment lag associated with certain "Other O&M" items.

1. Pennsylvania Corporate Net Income Tax and Pennsylvania Capital Stock Tax

a. Positions of the Parties

ME's and PN's lead/lag studies calculate the payment lag associated with these taxes based on their use of the statutory "safe harbor" method for payment of these taxes, which entails four payments each of 25% of the second prior year's tax liability. Because they have used the "safe harbor" method, MEPN argue that their calculations are reasonable. By utilizing the safe harbor method for paying estimated taxes, MEPN arrived at a lag calculation of 30.8 days. (MEPN Sts. 11-R, Exh. MJS 1 and 2 at 12 and 13; R.D. at 81).

The OTS disagreed and recommended increasing the payment lag associated with these taxes from 30.8 to 55.8 days. The OTS stated that its adjustment is based on the statutory payment requirements pursuant to the Pennsylvania Tax Code, which establishes a prepayment system requiring four estimated payments of 22.5% on the 15th day of the third, sixth, ninth, and twelfth month of the calendar or fiscal year. According to the OTS, prepayment requirements are satisfied if 90% of the final tax liability is paid in the quarterly installments. The final payment of 10% is due when the corporate tax return is filed. Using this method, the OTS calculated the lag associated with these taxes to be 55.8 days. (R.D. at 81–82).

The OTS asserted that the safe harbor method used by MEPN requires four estimated payments equal to 100% of the second prior year's tax liability in order to avoid underpayment penalties. The OTS argued that MEPN's lag calculations under the safe harbor method are flawed because their calculations do not account for all payments and treat the four estimated prepayments as if they equal 100% of their final tax liability. The OTS contended that the four prepayments allow MEPN to escape underpayment

penalties but do not necessarily satisfy the entire tax obligation. The OTS opined that MEPN may have to remit a final payment to satisfy its tax obligation in full. According to the OTS, MEPN's lag calculation accounts for the four prepayments, but it does not reflect any final payment that may be necessary to satisfy the total tax liability. (R.D. at 82).

The OTS contended that MEPN's failure to account for a final payment resulted in a miscalculation of the weighted percentage for each payment. By failing to include the final payment, the OTS asserted that MEPN calculated the lag by weighing the four prepayments as if they equal 100% of the tax liability. Accordingly, the OTS asserted that doing so is erroneous if the prepayments are less than the total tax liability and MEPN may have to make a final payment to satisfy their entire tax obligation. The OTS believes that by incorrectly weighting the estimated prepayments against the final tax liability, the MEPN lag calculations are flawed and artificially low. Therefore, the OTS recommended an adjustment of \$1,506,000 for ME and \$1,772,000 for PN because its adjustment is based on an accurate calculation of the lag associated with these taxes of 55.8 days. (R.D. at 82).

b. ALJs' Recommendation

The ALJs agreed with MEPN. The ALJs found that the OTS argument assumes that these taxes will escalate every year, but that the OTS provided no evidence in support of this proposition. The ALJs noted that there is no evidence in the record that the Commonwealth either has already increased the rates of these taxes or intends to in the near future. The ALJs stated that while it is possible that the amount of taxes will increase due to MEPN producing additional taxable income, there is no evidence in the record that either ME's or PN's liability for these taxes have increased in years where the tax rates have remained constant. Furthermore, according to the ALJs, it is possible that the Commonwealth may reduce the rate of one or both of these taxes with the result that

ME's and PN's liability for these taxes could remain the same or decrease from that of previous years, causing a reduction in the payment lag. Therefore, the ALJs rejected the OTS' adjustments and concluded that the Companies' recommendation is reasonable and should be adopted. (R.D. at 82 – 83).

c. Exceptions

In its Exceptions, the OTS avers that the ALJs incorrectly adopted the artificially low 30.8 Pa CNI and Pa CS lag calculation posited by the Companies. The OTS rejoins that the Companies' lag calculations under the safe harbor method are flawed because the calculation does not account for all payments and treats the four estimated prepayments as if they equal 100% of the Companies' final tax liability. The OTS notes that the ALJs' reasoning that the OTS argument assumes that these taxes will escalate every year, is in error given that the safe harbor method, as an alternative to the estimated statutory method, should only be used when a Company has escalating tax liability. The OTS opines that it is imprudent cash management to use the safe harbor method when tax liabilities are decreasing because the Companies will pay more than necessary to satisfy its total tax liability. Furthermore, the OTS asserts that based on the Companies' decision to use the safe harbor method, it is logical to assume that the tax liabilities have been increasing. The OTS states that the Companies have not expressly denied making a final payment in testimony or briefs. Therefore, the OTS asserts that its analysis properly exposed this flaw in MEPN's lag calculation and its adjustments should be adopted. (OTS Exc. at 8-12).

In reply, MEPN rejoin that the OTS' principal argument is based on a "hypothetical" company and is dependent on assuming that there is an incremental final tax liability on top of the four "safe harbor" payments. As the ALJs concluded, the Companies aver this assumption is not supported in the record as these taxes could just as well remain the same or decrease, rather than increase, in any given year. MEPN also

criticize the OTS for the introduction of a new rationale that prudent cash management mandates use of the safe harbor method only when an increase in these taxes is assured. The Companies aver that there is no foundation in the record for this position as it assumes a prescience about ultimate tax liabilities. The Companies maintain that the use of the safe harbor methodology to avoid penalties is prudent even without the perfect foresight suggested by the OTS. (MEPN R.Exc. at 12-13).

d. Disposition

Based upon the evidence of record, we deny the Exceptions of the OTS and adopt the recommendation of the ALJs. We find that the Company's position, that the OTS' adjustment is based on a faulty assumption that there will be an incremental final tax liability above and beyond the four "safe harbor" payments, is reasonable and convincing. We are in agreement with the ALJs that there is no evidence in the record to support the OTS' assumption as there is no assurance that the final tax liability will not be satisfied by the quarterly installments.

2. Treatment of "Non-Cash" Items

a. Positions of the Parties

MEPN have included in their analysis items such as depreciation, amortization, deferred income taxes, and uncollectibles, claiming that they create a need for cash and, therefore, should be reflected in cash working capital. MEPN argued that the term "non-cash" expense is misleading because it suggests that there is or was no cash outlay, which is untrue. According to MEPN, each of these items reflects an outlay of cash. They explained that depreciation represents the return of capital that was actually invested on a cash basis in plant. Then, as soon as the depreciation expense is booked upon the delivery of service, the amount of the expense is credited to the depreciation reserve and net plant is reduced, thus ending the investor's right to earn a

return on that portion of the cash investment. However, the associated revenues representing the return of the cash capital investment are not received until the customer pays for the service, creating a cash working capital requirement to the extent of the lag between the booking of the depreciation expense and the receipt of the associated revenues. (R.D. at 83).

Similarly, according to MEPN, deferred taxes relate to timing differences between book and tax depreciation associated with actual cash invested in plant and are deducted from rate base, preventing the investor from earning a return on that portion of the cash investment. Even though the timing differences eventually turn around, at which time deferred taxes are booked as a current tax expense offset, with a reversal of the related rate base deduction, there is still a cash working capital requirement that must be recognized to the extent of the lag between the initial rate base deduction and the receipt of the associated revenues. MEPN argued that other so-called “non-cash” items also represent actual cash outlays that must be reflected in a cash working capital analysis. (R.D. at 84).

The OCA argued that including depreciation, amortization, deferred income taxes, and uncollectibles in the cash working capital claim is improper. According to the OCA, cash working capital is a measure of the Companies’ day-to-day cash needs which arise due to differences between the time when payment for the expenses incurred to render service must be made and the time when revenues resulting from the provision of that service are received. The OCA argued that depreciation, amortization and deferred income taxes are not cash expenses for which a payment must be made at a specified date. Therefore, according to the OCA, these expenses do not create a need for cash and are not properly included in the lead-lag study analysis to determine cash working capital. Additionally, the OCA averred that depreciation and deferred income taxes represent sources of internally generated funds. (R.D. at 84).

The OCA contended that the Commission has held that no consideration should be given to non-cash items in the cash working capital computation citing *Pa. PUC v. Phila. Suburban Water Co.*, 58 Pa. PUC 668, 674 (1984) (“we consider uncollectible accounts expense to be a non-cash expense and, as such, no return allowance will be granted”); *Pa. PUC v. Mechanicsburg Water Co.*, 80 Pa. PUC 212, 226 (1993) (elimination of non-cash items, such as amortization and written-off uncollectibles, from the cash working capital calculation); *Pa. PUC v. Roaring Creek Water Co.*, 81 Pa. PUC 285, 292 (1994); and *Pa. PUC v. Columbia Gas of Pa, Inc.*, 74 Pa. PUC 282, 300 (1990) (“any expense which does not require the utility to utilize cash funds does not require a CWC allowance”). The OCA concluded that the Commission should reject the Companies’ inclusion of non-cash items in its claim for cash working capital.

b. ALJs’ Recommendation

The ALJs agreed with the OCA’s position. The ALJs found that the prior Commission decisions cited by the OCA consistently reject including non-cash items in cash working capital. The ALJs state that, while MEPN point out some state utility commissions have adopted their position that non-cash items should be included in cash working capital, the decisions of other state utility commissions are not controlling in this proceeding. The ALJs maintain that prior Commission decisions are controlling. They concluded that MEPN have cited no Commission decisions in support of their position that non-cash items should be included within the calculation of cash working capital nor have they proven that the Commission should deviate from its prior decisions. Therefore, the ALJs adopted the position of the OCA and excluded the non-cash items from cash working capital. (R.D. at 85).

c. Exceptions

In their Exceptions, MEPN rejoin that the Commission should reconsider outdated precedent and reflect so-called non-cash items in cash working capital lead-lag studies with an appropriate revenue lag because these items at one time entail an outlay of cash. The Companies opine that although the ALJs might feel constrained to follow Commission precedent, it is entirely appropriate for the Commission to reconsider its prior decisions so as to adopt the more appropriate and theoretically sound position of those other state commissions. MEPN cite a Connecticut decision at *The United Illuminating Company*, Docket No. 01-10-1-, 2002 Conn. PUC LEXIS 183, at *103-04 (Ct. DPUC, Sept.26, 2002), as well as two New Jersey cases¹¹, as support for their position.

In reply, the OCA submits that the Commission precedent referred to by the Companies is not “outdated” and there is absolutely no basis for including non-cash items in cash working capital. The OCA reiterated that cash working capital is a measure of the Company’s day-to-day cash needs which arise due to differences between the time when payment for the expenses incurred to render service must be made and the time when revenues resulting from the provision of that service are received. It avers that depreciation, amortization and deferred income taxes are not cash expenses for which a payment must be made at a specified date and are, therefore, not properly included in the lead-lag study analysis to determine cash working capital. The OCA maintains that the ALJs correctly rejected the Companies’ proposal to include non-cash items in the cash working capital calculation based on Commission precedent. (OCA R.Exc. at 16-17).

¹¹ *Middlesex Water Company*, Docket No. WR 00060362, at 17 (BPU, June 6, 2001); *Public Service Electric and Gas Company*, Docket No. ER85121163 (BPU, April 6, 1987).

d. Disposition

Our review of the record evidence leads us to conclude that the ALJs recommendation relative to the treatment of “non-cash” items within the cash working capital analysis is reasonable and consistent with Commission precedent. We find that the OCA’s position that depreciation, amortization, deferred income taxes and uncollectibles are not cash expenses for which a payment must be made at a specified date is correct. Therefore, these expenses are not properly included in the lead-lag study analysis to determine cash working capital. We are not persuaded by the Companies’ arguments to deviate from our prior decisions on this issue and will continue to follow Commission precedent. Accordingly, the Exceptions of MEPN on this matter are denied.

3. Treatment of Transmission Costs

a. Positions of the Parties

MEPN contended that their distribution-related cash working capital request is distinct from the Federal Energy Regulatory Commission (FERC) allowance. Their position is that the Pennsylvania jurisdictional lag covered here is the time between MEPN’s load serving entity payment to PJM for transmission service, compared to receipt of customer revenues for transmission service. According to the Companies, the FERC jurisdictional cash working capital allowance relates to transmission owner revenue requirements associated with provision of network integrated transmission service. The Companies claim that the OCA is under the mistaken impression that the cash working capital allowance included in FERC-approved transmission rates is duplicative of the transmission-related cash working capital request included by MEPN in these proceedings. (R.D. at 85).

MEPN argued that just as certain transmission-related operations and maintenance costs must be recovered through retail rates, there are also transmission-

related cash working capital requirements that must be reflected in retail rates. According to MEPN, there are two distinct transmission-related cash working capital requirements. (R.D. at 85).

The OCA asserted that the Commission should reject inclusion of transmission costs in cash working capital. According to the OCA, the Companies are fully compensated for their share of the overall cost of service from the revenues which PJM collects for that service. The OCA maintained that such compensation is based on the fact that the Companies' transmission revenue requirements established by FERC include a cash working capital component approved by FERC in its rate setting process. The OCA claimed that including transmission costs yet again in the lead-lag study in setting distribution rates is improper because the Companies are already compensated for transmission related working capital requirements by their FERC approved revenue requirement. The OCA concluded that to the extent that MEPN believe that FERC has not properly measured the cash working capital requirement associated with transmission service, that is an issue to be pursued at FERC, not with this Commission. (R.D. at 86).

b. ALJs' Recommendation

The ALJs agreed with the Companies, noting that MEPN have two different roles. As an owner of transmission facilities, they provide transmission services to others by transmitting others' electricity and then receive payment for that service at a later date. The ALJs found that FERC includes a cash working capital component that includes a lag period in setting rates for others using MEPN transmission facilities. Furthermore, according to the ALJs, as load serving entities, MEPN pay PJM for transmission services and are later paid for the electricity they transmitted to others. The ALJs adopted MEPN's position that the FERC cash working capital calculation does not include this service. The ALJs found that these are two separate items and concluded that there is no double counting. (R.D. at 86).

c. Exceptions

The OCA excepts, stating that the Commission should reject inclusion of transmission costs within the Companies retail cash working capital claim because the Companies are already fully compensated for their share of the overall cost of transmission service from the revenues which PJM collects for that service. The OCA avers that the Companies' argument that the cash working capital transmission request is "totally distinct from the FERC allowance," as it relates to the Companies' obligations, is without merit and should be rejected. According to the OCA, FERC allows cash working capital to reflect the time between when the Companies render service and the Companies receive payment for that service. The OCA contends that if the Companies now wish to contend that the FERC method does not include the lag between the time the Companies pay PJM and when they are paid for the electricity they have sent to others, then the remedy is at FERC, not through Pennsylvania distribution rates. According to the OCA, adding a transmission service cash working capital claim to distribution rates results in a double-counting of what is already provided for by FERC. (OCA Exc. at 5-6).

In reply, MEPN note that the ALJs properly accepted their position that there are two separate transmission related roles, one associated with the Companies role as transmission owners which is reflected in FERC rates and the other role associated with the Companies as LSEs, which is not reflected in FERC rates. As a result, ME's and PN's transmission related cash working capital claim is not duplicative of the cash working capital of their FERC rates and the argument of the OCA is fallacious and should be rejected. (MEPN R.Exc. at 13-14).

d. Disposition

Based upon the evidence of record, we will deny the Exceptions of the OCA and adopt the recommendation of the ALJs. We disagree with the OCA's position that the cash working capital allowance included in FERC-approved transmission rates is duplicative of the transmission-related cash working capital request included by MEPN. We find that MEPN are correct that there are two distinct transmission-related cash working capital requirements and that their request does not result in a double counting as alleged by the OCA.

4. Treatment of Return on Equity and Payment Lag Associated with Interest on Long-Term Debt

a. Positions of the Parties

MEPN urged the Commission to adopt their position that return on equity and interest are paid from operating income that is the property of the investor immediately upon the rendition of service. MEPN admitted that there is precedent to the contrary, but contended that these proceedings provide an opportunity for the Commission to adopt a proper approach to these related cash working capital issues. MEPN asserted that these items should be included in the lead/lag study with a zero payment lag. MEPN contended that their position has long been accepted by the New Jersey Board of Public Utilities. (R.D. at 87).

The OCA argued that interest should be treated as an expense and should be included in the study with a payment lag reflecting the terms of the debt, while return on equity should be excluded from the study. The OCA contended that including the return on equity in the lead-lag study also overstated the cash working capital needed and allows the Companies to earn an improper overall return on equity. According to the OCA, this treatment of the return on equity in the cash working capital provides daily

compounding of the allowed rate of return. The OCA concluded that the Commission should reduce each of the Companies' claims for cash working capital to reflect accepted ratemaking procedure. (R.D. at 87).

b. ALJs' Recommendation

The ALJs agreed with the OCA's position noting that while MEPN cite decisions from the New Jersey Board of Public Utilities as support for their position, the decisions of other state utility commissions are not controlling in this proceeding. The ALJs found that prior Commission decisions must be followed. They state that MEPN have cited no Commission decisions in support of their position nor have they proven that the Commission should deviate from its prior decisions. Therefore, the ALJs adopted the OCA position. (R.D. at 87).

c. Exceptions

In their Exceptions, MEPN reiterate their position that the Commission should reconsider outdated precedent and include return on equity and interest on long-term debt in cash working capital lead-lag studies with a zero payment lag, for the reasons already articulated. The Companies opine that while the ALJs may be bound by prior Commission precedent, the Commission should reconsider this issue and adopt the more appropriate and theoretically sound approaches of other state commissions. (MEPN Exc. at 24-25).

In reply, the OCA rejoins that the Commission should not stray from well-established Pennsylvania precedent that excludes interest expense and return on equity in the cash working capital calculation. The OCA maintains that the Companies have provided no support for departing from long-standing Commission precedent. (OCA R.Exc. at 17-18).

d. Disposition

Our review of the record evidence leads us to conclude that the ALJs recommendation relative to the treatment of return on equity and interest on long-term debt within the cash working capital analysis is reasonable and consistent with Commission precedent. We are in agreement with the OCA's position that interest should be treated as an expense and should be included in the lead-lag study with a payment lag reflecting the terms of the debt and that return on equity should be excluded from the study. We are not inclined to adopt ME's and PN's requests that we vary from well-established Commission precedent, as their request is unsupported in the record. The decisions cited by the Companies are not controlling in this proceeding. Accordingly, the Exceptions of MEPN on this matter are denied.

5. Payment Lag Associated with Certain "Other O&M" Items

a. Positions of the Parties

MEPN contended that Other O&M constitutes less than 10% of Total O&M, and consists of some items with payment terms less than 30 days and some greater than 30 days. Therefore, according to the Companies, use of the "standard" 30-day O&M payment lag is reasonable. MEPN stated that while it is theoretically possible to analyze the payment lag associated with each Other O&M item separately, any additional precision would be outweighed by the additional time and resources required for such an assessment. (R.D. at 88).

The OCA contended that interest on customer deposits that are paid annually should be separately accounted for, and that specific payment lags on pole rentals should be reflected in the lead/lag study, rather than including both items under "Other O&M." The OCA argued that interest on customer deposits is not an O&M

expense, rather it is an interest expense included in the cost of service. According to the OCA, there is no reason to assign a lag of thirty days to interest on customer deposits. The interest is paid on customer deposits annually and the Commission should use an average payment lag of 182.5 days. (R.D. at 88).

The OCA asserted that the Companies both receive pole rentals from telecommunications companies and pay pole rentals to those same companies. Both categories of payments are based on annual contracts billed after the end of the year. As a result, OCA stated there are significant lags in both receipt of payments from the Telecommunications companies and payment to those companies. According to the OCA, the Companies only recognized a long lag in the receipt of revenue but used thirty days as the lag for payment of expenses. For the sake of consistency, the OCA concluded that the Companies should recognize that the lag for payment of pole rentals to the telecommunications companies is as long as the lag in the receipt of revenues. (R.D. at 88).

b. ALJs' Recommendation

The ALJs agreed with the OCA's positions noting that interest on customer deposits is not an O&M expense, but is included in the cost of service. Therefore, the ALJs concluded that the actual average payment lag of 182.5 days should be used. The ALJs also agreed with the OCA that both payments to and from telecommunications companies should use lags that are consistent since the actual amounts are billed after the end of the year. Therefore, according to the ALJs, the lag time for payment to the telecommunications companies shall be the same as the lag period for the receipt of revenue from the telecommunications companies or 467.4 days for ME and 324.3 days for PN. (R.D. at 88 – 89).

c. Disposition

No Party excepts to the ALJs' recommendation in regard to this issue. Finding the ALJs' recommendation to be reasonable, appropriate and in accordance with the record evidence, it is adopted.

VIII. REVENUES AND EXPENSES

A. Universal Service Charge Deferral Recovery Period and Imposition of Carrying Charges

1. Positions of the Parties

a. Deferral Recovery Period

Pursuant to Section I.2 of their Restructuring Settlement, MEPN was permitted to implement and seek recovery of Universal Service and Energy Conservation costs if the programs' expenses exceeded the amounts established in the Commission's Order. Accordingly, ME deferred \$182,000 and PN deferred \$3.929 million of such costs for consideration in this proceeding. (ME Exh. RAD-2 and PN Exh. RAD-4, at 23; MEPN MB at 59-60; R.D. at 92).

The OTS opined that the appropriate recovery period is five years and that the Companies proposed three year recovery period violates the public interest as being unduly burdensome and because the expenses were accumulated over a six year period ending in 2004. (OTS MB at 17 - 18).

The Companies contended that a three year recovery period is appropriate and that if the OTS' five year proposal is adopted, some of the deferred costs would not be recovered until thirteen years after they were incurred. (MEPN MB at 60).

b. Imposition of Carrying Charges

The Companies have also proposed, as a matter of “economic fairness,” a 6% carrying charge, applicable to the unrecovered balance resulting in a claim of \$13,000 and \$285,000 by ME and PN, respectively. Additionally, the Companies believe that the absence of specific language in the Restructuring Settlement does not prohibit them from seeking recovery of carrying costs on these deferred expenses. (MEPN MB at 60). OTS argued that the omission of carrying charges on these deferred costs in the Restructuring Settlement was intentional and agreed to by the Companies as a part of that Settlement. (ME Exh. RAD - 2 and PN Exh. RAD - 4, at 23; MEPN MB at 59 - 60; OTS MB at 18 - 19; R.D. at 92).

Section I.I.2. of the Companies’ Restructuring Settlement states in part that:

“...Only to the extent that the Companies’ funding of these programs exceeds the amounts set forth in the Commission Order prior to the end of the distribution and transmission rate cap, may the Companies defer and seek recovery of such costs (net of any cost savings attributable to the programs) after the expiration of that rate cap.”

2. ALJs’ Recommendation

a. Recovery Period

The ALJs agreed with the OTS’ position that the three year recovery period proposed by the Companies would be burdensome because ratepayers will be required to pay the ongoing annual expense plus two years of deferred expenses for each of the next three years. Such a result is unreasonable in light of the fact that these costs were accumulated over a six year period. The ALJs found that the Companies failed to prove that a three year recovery period is either just or reasonable, and that it is in the public interest to mitigate the size of the annual charge to ratepayers while still allowing the

Companies to recover the entirety of these deferred expenses. Consequently, the ALJs adopted the OTS' five – year recovery period for these deferred expenses. (ME Exh. RAD - 2, PN Exh. RAD - 4 at 23; OTS MB at 20; R.D. at 92 – 94).

b. Imposition of Carrying Charges

The ALJs found that the inclusion of carrying charges would be an alteration of the terms agreed to in the Restructuring Settlement. While the Settlement does not expressly prohibit such charges, the very fact that carrying charges are not specifically provided for in the Restructuring Settlement, according to the ALJs, is sufficient reason to disallow these claims. In the ALJs' opinion, had carrying charges been contemplated and agreed to for deferred universal service costs, such a term would surely have been expressly stated in the Restructuring Settlement. Additionally, the ALJs found that the request for carrying charges must be denied as it violates the prohibition against earning a return on and a return of O&M expenses. As such, the ALJs found that the Companies are not permitted to earn a return on and a return of such operating and maintenance expenses thereby disallowing the \$13,000 claimed by ME and the \$285,000 claimed by PN. (ME Exh. RAD - 2, PN Exh. RAD - 4 at 23; OTS MB at 17 – 20; R.D. at 92 – 94).

3. Disposition

No Party excepts to the ALJs' recommendation in regard to this issue. Finding the ALJs' recommendation to be reasonable, appropriate and in accordance with the record evidence, it is adopted.

B. Payroll Expense

1. Positions of the Parties

ME's post-test year payroll claim is \$554,000 and PN's claim is \$572,000. (ME Exh. RAD-2 at 19; OCA Exh. TCS – 1 and 2 at Schedule 8). The OCA has proposed to eliminate the Companies' post-test year payroll increase adjustments for union and non-union employees. The OCA reasons that these increases are not scheduled to take place until two to four months after the future test year and that the non-union increases are not contractually required. (OCA St. No. 3; PN St. No. 4 – R at 15; OCA MB at 46; R.D. at 94).

The Companies have asserted that “[a]mple precedent supports the allowance of post-test year adjustments as requested in this proceeding”, citing *Pa. PUC v. Dauphin Consolidated Water Supply Company*, 55 Pa. PUC 44 (1981) and *West Penn Power Co. v. Pa. PUC*, 412 A.2d 903 (Pa. Cmwlth. 1980). (MEPN MB at 60 – 61; R.D. at 94). It should be noted that in *Dauphin*, the Commission adopted the ALJ's recommendation and rejected inclusion of a pay raise which employees began to receive nine months after the test year end.

2. ALJs' Recommendation

The ALJs found that the OCA's proposal to eliminate the Companies' post-test year payroll increase adjustments for employees should be rejected stating that these costs are known and measurable and are either contractually required by collective bargaining agreements or are reasonable management actions to promote the retention of experienced, skilled non-union employees. *See, Pa. PUC v. Pennsylvania-American Water Co.*, 2002 Pa. P.U.C. LEXIS 1, which allowed an annualization of salary increases for union and non-union employees for a six-month period following the future test year. *Pa. PUC v. Pennsylvania-American Water Co.*, 1995 Pa. P.U.C. LEXIS 170. In this case

the Commission allowed a similar company adjustment which was to be implemented within six months of the end of the future test year. In *Pa. PUC v. National Fuel Gas Distribution Corp.*, 73 Pa. P.U.C. 552 (1990), the Commission allowed the company to project both union and non-union payroll increases for five months beyond the end of the future test year. In *Pa. PUC v. UGI Corp.*, 58 Pa. P.U.C. 155 (1984), the Commission allowed both union and salary increases imputed by the Company during the first six months following the end of the future test year.

In rejecting OCA's proposal to eliminate the Companies' post-test year payroll increase adjustments, the ALJs also rejected the OCA's proposed incremental benefits expense and payroll taxes adjustments that would have been necessary if the OCA's proposal to eliminate the Companies' post-test year payroll increase adjustments had been accepted. (OCA MB at 46 – 47; R.D. at 95, 96).

3. Disposition

No Party excepts to the ALJs' recommendation in regard adoption of the OCA's adjustments. Finding the ALJs' recommendation to be reasonable, appropriate and in accordance with the record evidence, it is adopted.

C. Pension Expense

1. Positions of the Parties

MEPN claimed test year pension expense of \$2,842,000 and \$2,827,000, respectively, based upon the service cost component of pension costs under Statement of Financial Accounting Standards (SFAS) No. 87. However, the Companies testimony stated that no actual cash contributions to the pension plan will be made in 2006 or 2007, (OTS Exh. No. 2, Sch. 1). The plans are currently over-funded because of substantial payments made in 2004 and 2005. (R.D. at 95). In 2004 and 2005 ME made pension

contributions of \$38.8 and \$35.0 million and PN made pension contributions of \$50.3 and \$20.0 million, respectively. (MEPN Sts. 4-R, Exh. RAD – 79).

The OTS contended that the Companies' pension expense claims are not based on sound ratemaking principles and must be rejected. The OTS explained that the purpose of SFAS No. 87 is to allow the user of the financial statements to compare the pension plans and expenses among different companies. SFAS No. 87 does not, however, address funding requirements of pension plans or the ratemaking treatment of the expense; therefore, the amount is not designed to be recovered in a rate proceeding as proposed by the Companies. Moreover, the Companies use of a single cost component to determine their pension expense claims improperly inflated their pension claims for ratemaking purposes because the Companies failed to offset the service cost by the return on plan assets. (R.D. at 95 – 96).

The OCA agreed with the OTS' criticism of the Companies' proposal. The OCA stated that using only the service cost component of pension costs under SFAS No. 87 will always result in a positive outcome whether any cash contribution is made or whether the SFAS No. 87 amount is negative or positive. (OCA MB at 46; Tr. at 931).

Both the OTS and the OCA point out that the Commission has commonly utilized the principle that recovery of pension expense is limited to recovery of actual cash contributions to the pension fund, citing *Pa. PUC v. West Penn Power Co.*, 73 Pa. PUC 454, 119 PUR4th. 110 (1990), *Pa. PUC v. Metropolitan Edison Co.*, 78 Pa. PUC 124 (1993). Inasmuch as the Companies made no cash contributions to the pension fund in the 2006 future test year, and do not plan to make any cash contributions in 2007, both the OTS and the OCA contend that the Companies' pension expense claims should not be allowed. (R.D. at 96).

The Companies contend that the Commission has departed from the actual cash contribution principle, citing *Pa. PUC v. PPL Electric Utilities Corporation (PPL)*, Docket No. R-00049255, (Order entered December 22, 2004), in which the Commission approved PPL's calculation of pension expenses on an accrual basis. (R.D. at 96). PPL was permitted to use accrual accounting in its 1995 base rate proceeding and that accounting methodology was reaffirmed in PPL's 2004 proceeding. ME requested to change to accrual accounting in its 1993 rate case and its request was expressly denied by the Commission. *Pa. PUC v. Metropolitan Edison Co.*, 78 Pa. PUC 124 (1993).

In the alternative, the Companies argued that if the Commission uses the actual cash allowance method for pension expense, it should take a longer term view and adopt the Companies' method of (i) using actual payments made in 2004 and 2005, (ii) using the appropriate percentage assigned to O&M expenses, and (iii) dividing by ten years to get a normalized pension expense. The Companies contend that this longer term view of periodic cash contributions is consistent with the Commission's calculation of net negative salvage claims which has been a long accepted Commission policy. (R.D. at 97). The portion of pension contributions allocated to O&M expense is 56.52 percent for ME and 44.25 percent for PN. (MEPN Sts. 4 - R, Exh. RAD - 79).

The OTS pointed out that this proposal ignores the fundamental principle that ratemaking is designed to be forward looking, and that the purpose of the future test year is to establish an on-going level of expense. The Companies will not make a pension contribution in the future test year or in the foreseeable future; therefore, this alternative proposal must also be rejected. (OTS MB at 16; R.D. at 97).

2. ALJs' Recommendation

The ALJs agreed with the position taken by the OTS and the OCA. The Commission's prior decisions are clear; pension expense should be recovered on a cash

only basis. Additionally, the Companies pension trusts are over funded and IRS regulations do not allow for tax deductible contributions in this situation. *Pa. PUC v. West Penn Power Co.*, 1994 Pa. PUC LEXIS 144. (R.D. at 96 - 97).

The ALJs found that the Companies have failed to meet their burden of proof to demonstrate that the Commission should depart from prior practice and calculate pension expense on an accrual basis. (R.D. at 96).

Additionally, the ALJs found that the use of the actual cash contribution method prohibits use of the Companies' normalization proposal. The plain facts are that the Companies made no cash contributions to the pension funds in 2006, do not plan to make any actual cash contributions in 2007, and have no definite plans to make actual cash contributions to their over funded pension plans in the foreseeable future. (R.D. at 97).

For all of the foregoing reasons, the ALJs adopted the OTS' adjustment and found that the claimed pension expense of \$2,842,000 for ME and \$2,827,000 for PN should be disallowed.

3. Exceptions

In its Exceptions, the Companies contend that the ALJs improperly failed to adopt either their service component or alternative normalization methodologies as a basis to recover pension expense from ratepayers. The Companies assert that the ALJs' disallowances are contrary to recent Commission precedent and sound public policy. (MEPN Exc. at 25 – 26).

In their Reply Exceptions, the OCA pointed out that the ALJs recognized that the Commission has commonly utilized the principle that recovery of pension

expense is limited to actual contributions to the fund and that the ALJs correctly noted “the plain facts are that the Companies made no cash contributions to the pension funds in 2006, do not plan to make any actual cash contributions in 2007, and have no definite plans to make actual cash contributions to their over funded pension plans in the foreseeable future.” (R.D. at 96 – 97; OCA R.Exc. at 18). Additionally, the OCA emphasized that the Companies method of using only the service cost component of the pension costs under SFAS No. 87 will *always* result in a positive outcome because the service component ignores the extent to which sufficient pension fund assets already exist to meet the pension obligations that result from the service provided by the current employees. (OCA M.B. at 47; Tr. 931; OCA St. 3 at 15; OCA R.Exc. at 19).

The OTS, in their Reply Exception to this issue, addresses the Companies’ assertion that the only way to recover pension expense through rates is to contribute to pension funds only when a base rate case is planned. The Companies take this argument one step further and state that this could lead to recovery in rates of substantial pension contributions that would not be replicated for some time. (MEPN Exc. at 26). This slippery slope argument fails to acknowledge that utilities are required to make contributions to pension funds subject to minimum ERISA requirements and maximum limitations of the Internal Revenue Code. These rules ensure that pension contributions are sufficient to meet future obligations and do not result in excessive asset levels. As an added protection against over recovery through rates, the OTS and OCA participate in base rate proceedings and analyze expenses claimed by the utility to ensure that ratepayers will not be harmed. Therefore, the concern of the Companies that use of the actual cash contribution method may harm ratepayers because it sends a signal to utilities to make high pension contributions only when a base rate case is planned, is without merit. (OTS R.Exc. at 10 – 11). At page thirteen of its Reply Exceptions, the OTS states that the Companies’ Exceptions fail to recognize that there is long standing Commission precedent controlling the net negative salvage calculation, determining a consolidated tax adjustment based on the modified effective tax rate method, and recovery of pension

expense under the actual cash contribution method. Each ratemaking item is dealt with in a separate and very distinct way. The Companies' misguided attempt to compare treatment of pension expense with net negative salvage and consolidated tax savings violates fundamental ratemaking principles and fails to provide a sound justification to grant its request to normalize out of test year pension expense over a ten year period. Therefore, the recommendation to disallow the claimed pension expense should be adopted by the Commission.

4. Disposition

In prior Commission decisions, we have allowed utilities to include within base rates only the amount of actual pension contributions made during the test year. In *PPL* we allowed the company to use an accrual method, similar to what is used to account for benefits other than pensions to retired employees, to develop its expense level for pension contributions. We re-affirmed this accrual method for PPL in its subsequent base rate proceeding. Fundamentally, we believe that, regarding the recovery of pension expense, the alternative method requested by MEPN in this proceeding is fair to both ratepayers and stockholders. The Companies' normalization methodology will provide a more consistent and less variable expense claim to be included within base rates as compared to the more significant sums contributed in the two years preceding the 2006 test year in this proceeding. Additionally, we should not ignore this significant benefit to current and former employees just because the Companies' did not make a contribution to the pension fund during any given year.

We do not find the Companies' being barred from making a tax deductible contribution for federal income tax purposes to be persuasive. The development of base rates and the computation of net income for federal tax purposes may have similarities, but they also have significant differences, and we believe that tax deductibility should not

govern the appropriateness of inclusion of any expense item within the development of a utility's revenue requirement.

We shall grant the Companies' alternative normalization methodology for recovery of pension expense over a ten year period. We believe that it is incumbent upon us to develop base rates that are just and reasonable not only to the ratepayer but to the company as well. Therefore, based upon the discussion above we shall deny the Parties Exceptions to this issue and grant the Companies' request. This will provide for an allowance of pension expense of \$3,842 million and \$2,984 million for ME and PN, respectively.

D. Other Post Employment Benefits (OPEB)

1. Positions of the Parties

ME's test year OPEB expense claim is \$1,227,000 and PN's is \$1,297,000, based upon the service cost component of SFAS No. 106. The Companies' justification is that the actuarial-determined service cost component of SFAS No. 106 should be used to determine the Companies' OPEB expense in this case for the same reasons the service cost should be used to determine the Companies' pension expense.

The OCA, in an attempt to be philosophically consistent with its argument regarding the need to use all components under SFAS No. 87 in relation to pension expense, argues that the Companies must use the full actuarial cost pursuant to SFAS No. 106. This results in an OCA proposed increase in OPEB expense. (R.D. at 98).

2. ALJs' Recommendation

The ALJs found that the Companies have established the level of expense for OPEB for which they have provided proof. As the parties with the burden of proof on

this issue, the ALJs determined that the Companies only proved by a preponderance of the evidence that their just and reasonable OPEB expense is \$1,227,000 for ME and \$1,297,000 for PN. This is the level of expense of which all other parties and the Companies' customers were given notice. As such, the ALJs opined that the initial claim established a "cap" on the claim for this proceeding. Consequently, the ALJs recommended rejection of the OCA's adjustment and approval the Companies' OPEB expense claim. (R.D. at 98).

3. Disposition

No Party excepts to the ALJs' recommendation in regard adoption of the OCA's adjustments. Finding the ALJs' recommendation to be reasonable, appropriate and in accordance with the record evidence, it is adopted.

E. Rate Case Expense

1. Positions of the Parties

The Companies requested \$2.5 million in rate case expense to be amortized over three years, which results in an annual claim of \$833,333. No party has taken issue with the Companies' rate case expense level. However, the OTS seeks normalization over five years rather than three years as proposed by the Companies. (R.D. at 98).

The Companies argued that there is no basis for normalizing this claim over five years. They claimed that the OTS' attempt to analyze historic rate case filings to develop the five year period is misplaced for a few reasons: (i) because of rate caps, there have been very few rate cases for over a decade so no meaningful information can be determined from past history, (ii) since the Companies' transmission and distribution rate caps have now expired, there is a greater likelihood of more frequent rate filings (it has been less than three years since the Companies' T&D rate caps expired and they are

already seeking relief), and (iii) PPL's request for a two year normalization of rate case expense in its 2004 distribution rate case was unopposed and adopted by the Commission. (R.D. at 99).

The OTS contends that the arguments posited by the Companies are baseless and must be rejected in favor of the OTS recommended five year normalization period. (R.D. at 99).

2. ALJs' Recommendation

The ALJs explained that with regard to the first argument put forth by the Companies, the OTS recognized that the rate caps prevented a rate case filing in the last decade; however, a review of the filing frequency before the implementation of the rate caps reveals that the Companies had unusually long intervals between rate case filings. For example, ME's most recent rate cases were filed in 1984 and 1992 and PN's most recent rate case was filed in 1984. Although the Competition Act established the rate caps, nothing prevented the Companies from filing rate cases on a regular basis prior to 1996. Although it is convenient to use the rate caps as a justification for an expedited recovery period, a three year recovery period is unwarranted given ME's and PN's history of long stay outs between rate case filings. (R.D. at 99).

Second, the Companies assertion that there is a "greater likelihood" of more frequent filings now that rate caps have expired is merely a statement of future intentions, which is highly speculative. The Commission relies on a filing history because that history is the most reliable barometer of when future rate cases will be filed. The filing history of MEPN does not support a three year filing cycle. The Companies' request to ignore those facts and instead rely on unpredictable future intentions must be rejected. (R.D. at 99 - 100).

Finally, the Companies' reliance on the PPL case is wholly irrelevant because normalization periods are specific to each company and are based on the historic frequency of base rate case filings. (R.D. at 100).

Upon consideration of both Parties' arguments, the ALJs recommended adoption of the OTS' position. In *Popowsky v. Pa. PUC*, 674 A.2d 1149 (Pa. Cmwlth., 1996), the Commonwealth Court held that "the period of normalization is determined by examining the utility's actual historical rate filings, not upon the utility's intentions." *Popowsky*, 674 A.2d at 1154. The ALJs found that the OTS demonstrated that the Companies' rate case filing history prior to the Competition Act does not justify a 3 year normalization. Adoption of the OTS' proposed 5 year normalization accounts for the Companies' long gaps between filings before the Competition Act prevented filings and the fact that from 1996 until 2004 the Companies were barred from filing. (R.D. at 100).

Accordingly, based upon the discussion above, the ALJs found that the OTS' \$333,333 reduction in rate case expense for MEPN must be accepted because it properly normalizes rate case expense over five years in lieu of the requested three year period.

3. Disposition

No Party excepts to the ALJs' recommendation in regard to the adoption of the OTS' adjustments. Finding the ALJs' recommendation to be reasonable, appropriate and in accordance with the record evidence, it is adopted.

F. Consolidated Tax Savings

1. Positions of the Parties

The Companies have developed their normalized federal income tax expense claims of (\$39.255) million for ME and (\$14.504) million for PN on a stand-alone basis. The OCA and the OTS proposed a consolidated tax savings adjustment based on the modified effective tax rate method¹² with a three year historical average¹³. (MEPN MB at 64; R.D. at 100).

The Companies contended that the stand-alone approach to tax expense is appropriate for them because post restructuring, there is no longer any basis for passing unregulated operations' income tax benefits through the consolidated tax process. The Companies believe that what they describe as “blind adherence to the actual taxes paid doctrine” is inappropriate. The Companies stated that the Commission should use this proceeding to address the economics of the consolidated federal income tax adjustment in a deregulated post-restructuring environment and adopt the Companies' stand-alone approach. (MEPN MB at 64 – 65; R.D. at 101).

In the alternative, the Companies posit that if the Commission nonetheless adopts the modified effective tax rate method to calculate consolidated tax savings, it must, in order to address these issues in a fair and equitable manner, do the following: (i) net both operating income (positive) and losses (negative) of the unregulated affiliates for the period 2003-2005, rather than selectively using only losses; (ii) exclude the losses of FirstEnergy's subsidiaries that existed in 2003-2005 but do not exist today; and (iii)

¹² The Modified Effective Tax Method excludes Investment Tax Credits and losses of regulated companies to prevent the flow-through of accelerated depreciation benefits. These exclusions are made to eliminate any concerns of potential IRS violations in these areas. (OTS St. No. 2 at 22).

¹³ The time period selected is representative of the prospective period in which the rates being set will be in effect. (OTS St. No. 2 at 21).

remove from the calculation the federal tax benefit of Merger debt interest expense. The Companies stated that if these adjustments are made there is no net tax benefit from blending the tax results of FirstEnergy's unregulated affiliates with the Companies. (MEPN MB at 65; R.D. at 101).

The OTS pointed out that the Companies do not file federal income taxes on a stand-alone basis; rather, their federal income taxes are filed as part of a consolidated group under the parent corporation, FirstEnergy. By filing a consolidated federal income tax return, tax savings arise because companies with negative taxable incomes offset the positive taxable incomes of other companies. Overall, this consolidation creates a lower net taxable income and generates a smaller actual income tax liability than if the same companies filed on a stand-alone basis. (OTS MB at 27; R.D. at 101).

The OTS opines that the Companies' failure to reflect these consolidated income tax savings violates both Pennsylvania judicial and Commission precedent because, for ratemaking purposes, these taxes are not actually payable due to the filing of a consolidated return and each company's participation in that return. Under the "actual taxes paid" doctrine, enunciated by the Pennsylvania Supreme Court in *Barasch v. Pa. PUC*, 507 Pa. 496, 491 A.2d 94 (1985), the practice of setting rates on a utility's stand-alone tax expense was rejected. The OTS stated that it is improper to include, for ratemaking purposes, tax expenses which, because of the filing of a consolidated tax return, are not actually payable. Accordingly, all tax savings arising out of participation in a consolidated return must be recognized in ratemaking; otherwise a fictitious expense will be included in rates charged to ratepayers. (OTS MB at 27; R.D. at 102).

Similarly, the OCA stated that the filing of a consolidated income tax return results in utility corporations paying less income tax in a given year than would be paid if each subsidiary filed separate returns. The savings result from the ability to take

advantage of the losses of the parent and some unregulated subsidiaries on a consolidated basis by utilizing the income of the regulated utilities and subsidiaries with taxable income to offset those losses. (OCA Statement 3 at 20). OCA also argued that giving consideration to such savings is consistent with the requirements of the Internal Revenue Code. (OCA MB at 49; R.D. at 102).

The OTS used the modified effective tax rate method in accordance with *Barasch v. Pa. PUC*, 548 A.2d 1310 (Pa. Cmwlth.1988). *See, also, Pa. PUC v. Pennsylvania Power and Light Co.*, 85 Pa. PUC 306 (1995). Pursuant to this case law, the OTS calculated a three year average of FirstEnergy consolidated tax savings and then allocated the tax savings generated by non-regulated companies to all regulated and non-regulated companies that have positive taxable incomes based on the percentage that each member's taxable income bears to the total of all positive taxable incomes in the group. (OTS (ME) St. No. 2 p. 20 – 23, OTS (PN) St. No. 2 p. 21 – 23; OTS MB at 28; R.D. at 102).

The OCA determined the tax savings attributable to the Companies in this proceeding by calculating the difference between the aggregate taxes that would have been paid on separate returns and taxes paid on a consolidated basis, and then determining the Companies' share of that difference. The OCA proposed that the average savings for a three year period be used in order to normalize the results and smooth out any fluctuations from year to year. (OCA MB at 49; R.D. at 103).

2. ALJs' Recommendation

The ALJs supported the OTS' and the OCA's use of the modified effective tax rate method as proper and in accord with Pennsylvania law. This comports with the actual taxes paid doctrine so that all tax savings arising out of participation in a

consolidated return are recognized in ratemaking and fictitious expenses will not be included in rates charged to ratepayers. (R.D. at 103).

The ALJs also found that the Companies' first proposed modification to the OTS' way of employing the modified effective tax rate method, (of netting both operating income (positive) and losses (negative) from the unregulated affiliates for the period 2003-2005, rather than selectively using only losses), must be rejected. This proposal ignores the very intent of the consolidated tax adjustment, which is to pass through to ratepayers the benefits of filing as part of a consolidated group. It is proper to allocate only the net losses because the OTS consolidated tax adjustment accounts for taxable income of all companies, both regulated and unregulated. The Companies' attempt to improperly change the allocation would allow them to obtain a disproportionate share of the losses by failing to recognize the total savings which would be shared by the consolidated group. As a result, less of the tax savings would be passed on to ratepayers. (MEPN MB at 65; R.D. at 103).

The ALJs noted that the OTS agreed with the Companies' second proposal, that the losses of subsidiaries that existed in 2003 – 2005 but no longer exist today must be excluded, and found that this modification is proper. (R.D. at 103).

Additionally, the ALJs noted that the Companies' third proposal, that the federal tax benefit of merger debt interest expense be removed, has been accomplished in the OTS' and the OCA's exclusion of this item from their proposed capital structures of the Companies. (OTS St. No. 1 at 12; OCA St. No. 3 – S at 13; R.D. at 104).

For the reasons set forth above, the ALJs recommended adoption of the OTS' consolidated tax adjustment of \$3,281,070¹⁴ for ME and \$212,610 for PN. (OTS St. 2-SR, Exh. 2, Sch. 4, ME/Revised; OTS St. 2-SR, Exh. 2, Sch. 4, PN Revised; R.D. at 104). These revised OTS adjustments account for the proper use of taxable income in lieu of tax liability for 2003 and 2004 as well as the exclusion of subsidiaries which no longer existed in 2005. Additionally, the OTS included other loss subsidiaries that were originally overlooked in its originally proposed adjustment.

3. Exceptions and Replies

MEPN except to the ALJs' adoption of the consolidated tax savings adjustment, which is based upon the modified effective tax rate method and utilized a three year average. Additionally, the Companies state that the ALJs made two technical errors, regarding merger debt interest and the elimination of loss subsidiaries that existed in 2003 – 2005 but no longer exist today. Finally, the Companies believe that the calculation should include both gain subsidiaries and loss subsidiaries. (MEPN Exc. at 29 – 31).

In its Reply Exceptions, the OTS states the ALJs correctly held that ME's and PN's calculation of federal income tax liability on a stand-alone, separate company basis violates the actual taxes paid doctrine because it does not recognize tax savings that arise out of participating in a consolidated return. The OTS states it is improper to include for ratemaking purposes, tax expenses which, because of the filing of a consolidated tax return, are not actually payable. Accordingly, the ALJs' adoption of the OTS consolidated tax adjustment properly recognized tax savings arising out of participation in a consolidated return and ensured that fictitious expenses will not be included in rates charged to ratepayers. (OTS R.Exc. at 14; R.D. at 103). Further, the

¹⁴ In Reply Exceptions the Parties agreed to Tables showing the OTS' adjustment to be (\$5,364,000) for ME and (\$212,610) for PN.

OTS states, in its Reply to this issue, that it has eliminated merger debt interest from the capital structure of the Companies thus removing the potential for any double accounting. (OTS R.Exc. at 15, n. 21; OTS St. No. 1 at 12). Lastly, the Companies' Exception asserting the ALJs failed to net the losses of all unregulated subsidiaries against their gains, in OTS' opinion, ignores the intent of the consolidated tax adjustment by failing to recognize the total savings which will be shared by the consolidated group. (OTS R.Exc. at 16).

In its Reply Exceptions, the OCA states that the Companies Exception regarding adoption of the modified effective tax rate method should be denied because to grant the Exception would not be in accord with Pennsylvania law. (OCA R.Exc. at 19 – 20).

4. Disposition

The OTS has employed the modified effective tax rate method utilizing a three year average, to compute its consolidated tax adjustment. Upon review of the OTS computation, the Companies offered refinements to the subsidiaries included within the three year average data. These refinements, along with several others, were incorporated into the final adjustments adopted by the ALJs. We believe that the ALJs properly rejected the Companies modification to net operating income as well as operating losses from unregulated affiliates to compute the tax savings. To do this, as explained by the ALJs, would ignore the intent of the adjustment. We also agree with the ALJs finding that the OTS' and OCA's exclusion of merger debt from the capital structure is a proper reflection of that debt interest and it need not be removed from the computation of federal income tax also, as it pertains to the issue of consolidated tax savings.

Accordingly, we shall adopt the recommendation of the ALJs and accept the consolidated tax savings adjustments as provided in the consensus tables provided by the Companies.

G. Investment Tax Credits and Excess Deferred Income Taxes

1. Positions of the Parties

Without proposing any particular adjustment, the OCA claimed that the Companies incurred a “windfall” associated with the treatment of unamortized Investment Tax Credits (ITC) and Excess Deferred Income Taxes (EDIT) under the Restructuring Settlement. However, the OCA acknowledged that the Companies’ affiliate Jersey Central Power & Light (JCP&L) sought and obtained a Private Letter Ruling from the Internal Revenue Service (IRS) in which the IRS determined that to flow-back the ITC and EDIT would constitute a tax normalization violation. Despite this fact, the OCA still insists the Companies obtained a “windfall” and should have taken action directly with the IRS. (R.D. at 104).

2. ALJs’ Recommendation

The ALJs agreed with the Companies that for them to have filed anything with the IRS after JCP&L received a Private Letter Ruling would have been futile. The ALJs found that because the Companies retained no benefit they were not permitted to have (i.e., they were not required to flow back these ITC and EDIT), there can be no “windfall” as OCA alleged. The prevailing IRS view is that the accumulated tax benefits of the ITC and EDIT cannot be flowed back to customers.¹⁵ The Companies’ stranded cost determinations in 2000 already reflected that view and, as such, there is no need to

¹⁵ Under IRS Regulation 1.46-6(b)4, a normalization violation would also occur if an indirect reduction in rates is intended to achieve a similar cost of service or rate base reduction.

make any adjustment to stranded costs for these items in this proceeding, which would result in a tax normalization violation. (R.D. at 104).

The ALJs found that there is no basis for any adjustments to the Companies' stranded costs as a result of the treatment of ITC and EDIT under the Restructuring Settlement.

3. Disposition

No Party excepts to the ALJs' recommendation. Finding the ALJs' recommendation to be reasonable, appropriate and in accordance with the record evidence, it is adopted.

H. Decommissioning Costs

1. Positions of the Parties

The Companies' claims for TMI-2 decommissioning expenses reflect a decrease of \$6.635 million for ME and a \$7.817 million increase for PN. These revised estimates are based on a 2004 site specific study. The Companies stated that these revised decommissioning costs will ensure adequate funding for important health and safety issues. The Companies are seeking additional decommissioning funding in the amount of \$15,600,000 (32% share) for ME and of \$11,700,000 (24% share) for PN of Saxton¹⁶ expenditures since 1999. These additional decommissioning costs are proposed

¹⁶ The Saxton nuclear facility, located in Bedford County, Pennsylvania began operations in November 1961 and shut down in May 1972. It had a net power output of 23.5 MW-thermal, and its purposes were primarily to research various aspects of nuclear reactor technology and to train personnel. The owners/operators were Saxton Nuclear Experimental Corp (SNEC) and GPU Nuclear. The plant has been decommissioned, and in November, 2005 the NRC released the site for unrestricted use. (http://en.wikipedia.org/wiki/Saxton_Nuclear_Generating_Station)

to be reflected in the Companies' CTC rates, to enable full recovery from customers by December 31, 2010, for ME and December 31, 2009, for PN. The Companies point out that the Competition Act supports the recovery of decommissioning costs based on new information that was not previously available, citing Section 2804(4)(iii)(F) of the Code, 66 Pa. C.S. § 2804(4)(iii)(F). (MEPN Sts. 4 at 34 – 38; R.D. at 105).

In its testimony, the OCA rejected the Companies' TMI-2 decommissioning claims on two grounds: first, that a license extension may be filed for TMI-2; second, that the nineteen percent contingency for TMI-2 decommissioning is not appropriate. The OCA accepted the Companies' decommissioning claims for Saxton, because these costs were not known during restructuring and were incurred after 1998. (R.D. at 105).

In their Recommended Decision, the ALJs mistakenly determined that the OCA did not brief its position regarding a decommissioning funding allowance for TMI-2 as part of its stranded cost requirement. Therefore, the ALJs determined that “consequently, [their arguments] are waived.” The ALJs then concluded that the Companies' decommissioning expense increase claims are supported by a preponderance of the evidence and should be approved. (R.D. at 105 – 106). The OCA did address the Companies' proposals in both Main and Reply Briefs. (OCA MB at 87 - 88; OCA RB at 53). Therefore, the ALJs' comment that OCA waived this issue is in error.

The OCA advocated that the Companies' estimates of the appropriate level of decommissioning funding for TMI-2 should be rejected and the allowance for TMI-2 decommissioning as part of stranded cost in this case should be set at zero (\$0). (OCA MB at 87).

The OCA stated that the Companies' claims are overstated due to their assumptions that the anticipated life extension request for the TMI-1 plant should not be

reflected and the Companies' use of an unnecessarily high contingency factor. (OCA MB at 87). The OCA stated that any allowance for TMI-2 decommissioning costs must consider the life extension request of TMI-1. (OCA MB at 87, citing OCA St. 3 at 26). This postponement "will reduce the need for additional funding contributions because the earnings in the decommissioning fund asset are expected to exceed decommissioning cost escalation." (OCA MB at 87, quoting OCA St. 3 at 27).

The OCA stated further that the Companies' estimated contingency allowance was more than twice the amount approved by the Commission in the Companies' restructuring proceedings and the contingency allowance approved in the last electric utility rate proceeding before restructuring. (OCA MB at 87, citing OCA St. 3 at 28). Therefore, the OCA believes that no additional contributions are required beyond that already scheduled for the Companies, even assuming no life extension occurs and utilizing only a 10% contingency allowance. (OCA MB at 88, citing OCA St. 3 at 28, Exh. TSC-3 at 2 and TSC-4 at 2).

The OCA stated that, even if the life extension is not filed, "the decommissioning process is scheduled to take over 20 years. This will certainly provide Met-Ed and Penelec adequate time to collect any additional funds necessary and still take advantage of the [decommissioning] synergies available." (OCA RB at 53, quoting OCA St. 3S at 17).

Accordingly, the OCA believes that there is substantial record evidence that the Companies' stranded cost recovery allowance for funding TMI-2 nuclear decommissioning costs should be set at zero (\$0) in this case. (OCA Exh. at 33 – 35; TS-3 at 2 and Exh. TS - 4 at 2).

2. ALJs' Recommendation

In its testimony, the OSBA does not address the claim with respect to ME, where there is a net decrease in all nuclear decommissioning costs (i.e., TMI-2 and Saxton) suggesting concurrence with the ME claims. With respect to PN, where there is a net increase in all nuclear decommissioning costs, the OSBA appears to oppose the request for funding. (R.D. at 105).

The OSBA did not brief these issues. Consequently, their arguments are waived. *Jackson v. Kassab*, 2002 Pa. Super. 370, 812 A.2d 1233 (2002), *appeal denied*, *Jackson v. Kassab*, 573 Pa. 698, 825 A.2d 1261 (2003), *Brown v. PA Dep't of Transportation*, 843 A.2d 429 (Pa. Cmwlth., 2004), *appeal denied*, 581 Pa. 681, 863 A.2d 1149 (2004).

The ALJs found that MEPN's TMI-2 decommissioning expense claims are supported by a preponderance of the evidence, are just and reasonable, and should be approved.

Additionally, the ALJs also found that the Companies' claims for additional Saxton decommissioning expense are supported by a preponderance of the evidence, are just and reasonable, and should be approved. (R.D. at 106).

3. Exceptions

The OCA excepted to the ALJs' finding that they did not brief this issue and has provided a detailed explanation of their position within their Main Brief and Exceptions. Notably, the OCA contends that the Companies' claims for decommissioning of TMI should be rejected as explained above.

In reply, the Companies state that the ALJs' holding regarding ME's TMI-2 decommissioning expense claim (a decrease of \$6.6 million) and PN's \$7.8 million decommissioning expense increase, is supported by a preponderance of the evidence, is just and reasonable, and should be approved. MEPN state that it is not appropriate to reject the TMI-2 claims based upon the unsupported assertion that a delay in decommissioning may occur due to the granting of a license extension for TMI-1. (MEPN R.Exc. at 14 - 15; R.D. at 105-106).

4. Disposition

We have reviewed the record evidence regarding the Companies' claimed decommissioning expense and find that the ALJs recommendation is reasonable. We do not find the arguments of the OCA to be persuasive, therefore, we shall adopt the recommendation of the ALJs and allow the Companies' claimed expense for decommissioning.

I. Community Action Association of Pennsylvania (CAAP) Claim

1. Position of the Parties

CAAP seeks an increase in the Companies' low income usage reduction programs (LIURP), called WARM, commensurate with any approved residential rate increase. CAAP explains that the Companies' WARM programs are designed to help low income customers reduce their energy consumption through education and conservation measures. In the current proceeding, for their WARM programs, ME proposes to spend \$1,826,000 in 2006 while PN proposes to spend \$1,962,000 in that same year. Those proposed spending levels are the same as the Companies' spent in 2002. In the present proceeding, if the Companies' requests are granted, rates for residential customers will increase and in order to ensure that the Companies' WARM programs remain appropriately funded and available, it is necessary to increase funding

for those programs commensurate with any rate increase imposed upon the residential class.

CAAP also points out that in its Declaration of Policy, the Competition Act provides in pertinent part that: “The Commonwealth must, at a minimum, continue the protections, policies and services that now assist customers who are low income to afford electric service.” Section 2801(10) of the Code, 66 Pa. C.S. § 2801(10).

CAAP argues that allowing residential rates to increase without a commensurate increase in the Companies’ WARM programs would not comport with this express policy of the Competition Act.

Citizen Power states that CAAP’s proposal is modest, and should be accepted.

2. ALJs’ Recommendation

CAAP chose to brief only one of its five proposals, namely that each Company’s LIURP program be increased by the same percentage amount of any rate increase granted in this proceeding. Accordingly, the ALJs determined that CAAP’s remaining proposals were waived. *Jackson v. Kassab*, 2002 Pa. Super. 370, 812 A.2d 1233 (2002), *appeal denied*, *Jackson v. Kassab*, 573 Pa. 698, 825 A.2d 1261 (2003), *Brown v. PA Dep’t of Transportation*, 843 A.2d 429 (Pa. Cmwlth., 2004), *appeal denied*, 581 Pa. 681, 863 A.2d 1149 (2004).

The ALJs found that by providing an increase to the Companies’ WARM programs’ funding levels commensurate to the increase allowed in residential rates, the Companies’ LIURP protection and services will continue to be maintained as envisioned

by the Competition Act. Accordingly, the ALJs found that CAAP's proposal should be approved.

3. Disposition

No Party excepts to the ALJs' recommendation. Finding the ALJs' recommendation to be reasonable, appropriate and in accordance with the record evidence, it is adopted.

J. Conservation and Renewable Initiatives: Retention of Riders and PennFuture Initiatives

1. Sustainable Energy Fund Riders

a. Positions of the Parties

The Companies proposed to eliminate both ME Rider G and PN Rider I from their tariffs. MEIUG, PICA and IECPA support the Companies' proposal while the Community Foundations¹⁷ and Citizen Power seek to retain these Riders. (SEF MB; Citizens MB at 40; R.D. at 108).

Each Rider states that "[t]he Company will establish a sustainable energy fund which shall be funded from the Distribution Charges in each Rate Schedule at the rate of 0.01 cents per KWH (less applicable gross receipts tax) on all KWH delivered to all Customers beginning on January 1, 2008 and continue until the Commission establishes new Distribution Charge rates." (Electric Pa. P.U.C. (Sup. 37); Second Revised Page 168; Effective: August 23, 2005).

¹⁷ Sustainable Energy Fund administrators for MEPN are the Berks County Community Foundation and the Community Foundation of the Alleghenies respectively.

At the time of the Restructuring Settlement, on December 31, 1998, the Companies funded the SEF through a combined lump sum payment of \$12.1 million, \$5.7 million from ME and \$6.4 million from PN. This payment delayed implementation of the 0.01¢ per kWh charge for each Company until January 1, 2005, when the transmission and distribution rate caps were set to expire. (ALJ Exh. 1 at 49). In effect, the Companies agreed to forego 0.01 cents per kWh of distribution revenues to which shareholders would otherwise have been entitled as part of the unbundling of rates for purposes of funding the SEF. As part of the settlement resolving the GPU/FirstEnergy merger in 2001, the Companies agreed to provide another lump sum payment totaling \$5 million, thereby further delaying implementation of the 0.01¢ per kWh charge until January 1, 2008. Thus, the burden of this funding has never been borne by the ratepayers; rather, the Companies' shareholders have shouldered these costs. (R.D. at 109).

b. ALJs' Recommendation

The Commission has previously determined that SEF funding through distribution charges is to be terminated. Citing to “the Legislature’s creation of a permanent statutory funding source”¹⁸ for endeavors such as those supported by SEF, the Commission held at page 52 in *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-00049255 (Order entered December 22, 2004), that “now is the appropriate time to begin eliminating the use of distribution revenues to support the SEF.” *See, also, Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-00049255, (Order entered April 1, 2005), where the Commission stated that it had accepted PPL’s Compliance Filing which included an SEF Rider that phases out PPL’s .01 cent per kWh charge to zero as of January 1, 2007. (R.D. at 110).

¹⁸ The reference is to the Alternative Energy Portfolio Standards Act (AEPS) signed into law by Governor Edward G. Rendell on November 30, 2004.

The Commission's stated goal of making the SEF self-sustainable will be advanced by permitting the Companies to eliminate ME Rider G and PN Rider I from their tariffs. As MEIUG and PICA and IECPA point out, if the Companies desire to continue funding the SEF from shareholder funds they are free to do so. (MEIUG/PICA MB at 72; R.D. at 110, 111).

The ALJs stated that the effect of retaining ME Rider G and PN Rider I in their tariffs will be to impose upon ratepayers, commencing January 1, 2008, a charge they have hitherto not paid. MEIUG and PICA and IECPA oppose this shifting of the costs of SEF to ratepayers, in conjunction with the other rate increases proposed in this proceeding, as unduly burdensome. (R.D. at 109, 110).

Based upon the reasoning above, the ALJs support the position of the Companies and recommended elimination of Rider G from ME's tariff and Rider I from PN's tariff. (R.D. at 111).

c. Exceptions

The SEFs except to the ALJs' analysis and recommendation concerning continued funding which concluded that removal of the funding Riders is both just and reasonable and in the public interest. The SEFs stated that their initiatives ultimately assist ratepayers with education and implementation of conservation and renewable initiatives that encourage customers to conserve, among other things. As asserted by the SEFs, when properly viewed in this way, ratepayer funding of such initiatives is not a burden at all. To the contrary, the rate-paying public actually benefits from SEF initiatives. In its Exceptions, the SEFs state that there is undisputed evidence of record which demonstrates that projects they have funded provide benefits to the distribution system and also to distribution service customers. Additionally, from a ratemaking point

of view, there is a return to distribution service and to its customers from the funding of SEF projects – a return that justifies continued SEF funding through distribution rates. (SEF Exc. at 2).

The SEFs also except to the ALJs' finding that their interpretation of *Lloyd* is incorrect by finding that the Commonwealth Court did not address the question in this case of whether or not SEF has to be provided at all. (SEF Exc. at 11; R.D. at 110).

Lastly, the SEFs contend that the initiation of the Commission's *Investigation of Conservation, Energy Efficiency Activities, and Demand Side Response by Energy Utilities and Ratemaking Mechanisms to Promote Such Efforts*, Docket No. M-00061984 (Order entered October 11, 2006), supports the continued funding of SEF. (SEF Exc. at 11).

In their Reply to the Exceptions of PennFuture on these issues, MEIUG/PICA support the finding of the ALJs regarding *Lloyd* and stated that the issue in this case is whether the Companies' ratepayers should provide funding at all and does not address continued funding, actually the phase-out of funding, as in *PPL*. (MEIUG/PICA R.Exc. at 22).

In their Reply Exceptions, the Companies state that the Commission's clear position in *PPL* was that "now is the appropriate time to begin eliminating the use of distribution revenues to support the SEF." (R.D. at 110, quoting *PPL* at 52). According to the Companies, the ALJs further noted that MEPN have already made available significant amounts (\$17.1 million) of seed money to the SEFs. (R.D. at 110). In addition, MEPN have already funded SEF through December 31, 2007. (ME St. 4 at 55; PN St. 4 at 49). The Companies contend that the ALJs properly observed that *Lloyd* does not address the question raised in this proceeding, i.e., "whether or not SEF has to be

provided at all." (R.D. at 110). The Companies assert that since the opposing Exceptions offer nothing new on this issue, the ALJs' finding is appropriate. (MEPN R.Exc. at 16).

d. Disposition

Upon review of the record on this issue as well as the Exceptions and Replies of the Parties, we shall adopt the reasoning and recommendation of the ALJs, which is supported by our recent decision in *PPL*, the Companies significant financial contribution to the SEFs, and the ALJs' interpretation of *Lloyd*.

2. PennFuture's Renewable Energy Initiatives

a. Positions of the Parties

PennFuture proposes a variety of renewable energy initiatives to be implemented by the Companies. Only one of the proposals is supported by the Commercial Group; a voluntary real time pricing rate schedule.

The Companies make the following observation about the renewable energy proposals in their Main Brief:

These new funding initiatives, however well intentioned, were not accompanied by any proposal addressing recovery of program costs. While [the Companies] are not opposed to implementing these types of programs, like [PennFuture's] \$30 million for renewable energy programs, the additional \$5 million for consumer education regarding the rate caps and [PennFuture's] request for \$30.6 million for DSM/energy efficiency expenditures, they can and will do so only if there is a clear and unequivocal rate mechanism in place for allowing for full and timely recovery of all costs incurred/expended in connection with these programs . . .

(MEPN M.B. at 68 – 69).

The OSBA, MEIUG, PICA and IECPA generally argue that PennFuture proposals should not be adopted. However, the OSBA does not oppose PennFuture's real time pricing proposal so long as participation is strictly voluntary and the program costs are recovered solely from participating customers. Additionally, MEIUG and PICA and IECPA do not oppose PennFuture's real time pricing proposal so long as it is limited to generation costs and is strictly voluntary. (R.D. at 111).

b. ALJs' Recommendation

Initially, the ALJs found that PennFuture bears the burden of proof as to its proposals to have the Companies incur expenses that the Companies did not include in their filings. As the proponent of a Commission order with respect to its proposals, PennFuture bears the burden of proof as to those proposals. 66 Pa. C.S. § 332(a). The provisions of 66 Pa. C.S. § 315(a) cannot reasonably be read to place the burden of proof on the utility with respect to an issue the utility did not include in its general rate case filing and which, frequently, the utility would oppose. Inasmuch as the Legislature is not presumed to intend an absurd result in interpretation of its enactments¹⁹, the burden of proof must be on a party to a general rate increase case who proposes a rate increase beyond that sought by the utility. (R.D. at 117).

Further, the ALJs found that PennFuture had failed to bear its burden of proof with respect to its rate increase proposals. According to the ALJs, PennFuture provided general ideas, but failed to address specifics for implementation and demonstrate that the proposals are in the public interest. While renewable energy initiatives may well be a laudable goal, credible evidence of their supposed benefits must be adduced. PennFuture has not done so. (R.D. at 118).

¹⁹ 1 Pa. C.S. § 1922(1), *PA Financial Responsibility Assigned Claims Plan v. English*, 541 Pa. 424, 64 A.2d 84 (1995).

The ALJs determined that PennFuture did not prove by a preponderance of the evidence that the additional rate increases it proposed are just and reasonable and in the public interest. PennFuture did not prove by a preponderance of the evidence that imposing standards that exceed those of AEPS with respect to the Companies' inclusion of a specific percentage of electricity from alternative resources is just or reasonable or in the public interest. The ALJs also determined that PennFuture did not prove by a preponderance of the evidence that the implementation of time-of-day pricing on a per kWh basis for the Companies' transmission and distribution rates is just or reasonable or in the public interest.

Accordingly, the ALJs recommended that the proposals put forward by PennFuture should be rejected.

c. Exceptions

In its Exceptions, PennFuture avers that the ALJs erred when they rejected its proposals²⁰ because (a) the Companies did not oppose the PennFuture proposals, (b) the Recommended Decision misapplied recent Commonwealth Court precedent, (c) the ALJs ignored substantial record evidence regarding the effectiveness and benefits of PennFuture-supported programs, and (d) the ALJs erred in applying AEPS. The PennFuture Parties submit that the Commission should reject the ALJs' recommendation and require the adoption of the renewable energy and other programs described in our testimony and briefs.

²⁰ R.D. at 111-19; 155-59; 223-26; 235; 255-57. The ALJs also rejected related proposals by other Parties for continued funding of the Sustainable Energy Funds. See, e.g., R.D. at 108-111.

d. Disposition

In deciding this issue, we focus on the provisions of 66 Pa. C.S. § 315(a) regarding burden of proof. Here, PennFuture attempts to place a significant amount of new costs upon the Companies for which the Companies have not requested recovery within their case-in-chief. When this occurs, the burden of proving these new costs are just and reasonable does not shift to the Companies but remains with PennFuture. We agree with the ALJs that PennFuture has not met its burden of proof regarding these new costs. Accordingly, we shall adopt the recommendation of the ALJs on this issue.

IX. RATE OF RETURN

A. Capital Structure

1. Positions of the Parties

MEPN proposed a capital structure consisting of 51% long-term debt and 49% common equity. (MEPN St. 7 at 7) Neither the OCA nor the OTS disagreed and stated that this is reasonable. (OTS St. 1, at 9-10; OCA St. 4, at 10-13). The OTS accepted this capital structure for the purpose of establishing appropriate returns in this proceeding as it is within the range of capital structures used by its witness. (OTS Exh. 1, Sch. 2.). The OCA recommended a capital structure consisting of 51% debt and 49% common equity, based upon its similarity to the Companies' pre-merger capital structures, the proxy group used by its witness and its support of a strong single A credit rating. (OCA St. 4 at 12 & 19; OCA St. 5S at 2). Included in ME's and PN's proposed capital structure are portions of FirstEnergy's merger acquisition debt.

The OCA and the OTS both objected to the methodology by which MEPN arrived at this proposed capital structure. The OCA objected to the methodology because it contends the methodology improperly includes goodwill and amounts to a request by

MEPN to impose an acquisition premium upon the ratepayers. The OCA contended that a condition of the Commission's approval of the FirstEnergy/GPU merger was that the Companies should not reflect in retail rates the acquisition premium. If the ratemaking capital structure is based on the goodwill amounts on the MEPN balance sheets, the OCA argued the acquisition premium is included in setting the authorized rate of return on the rate base for retail delivery service. The OCA concluded that this is improper and inconsistent with the Commission order prohibiting recovery of an acquisition premium through retail rates. (OCA St. 4 at 12-13., OCA St. 4S at 5-6).

Additionally, the OCA argued that while the Companies' method results in a reasonable capital structure in this case, it may not in future cases. (OCA St. 4 at 11-12). According to the OCA, the Companies' method artificially increases the embedded cost of debt component. (OCA St. 4 at 11-12). The OCA argued that the Commission should reject the Companies' procedure that allocates FirstEnergy's acquisition debt to MEPN. (OCA St. 4, at 10-13).

The OTS also argued that the Companies' capital structure is based on the misallocation of debt. To the extent that the Companies calculate the claimed capital structure by including a proportional share of FirstEnergy's debt securities used to finance the acquisition of GPU, the OTS argued the calculation is improper in this proceeding. According to the OTS, only debt used to finance the Companies' rate base is properly included in this proceeding. The OTS contended that including debt for the acquisition of GPU is not appropriate in determining the Companies' capital structure. (OTS M.B. at 32).

In response to the OTS and OCA position opposing allocation of FirstEnergy's acquisition debt to MEPN, the Companies replied that since the acquisition, they have incurred depreciation and amortization expenses and these expenses have altered the equity component of capitalization. MEPN opined that it is

unreasonable to assume that an amount equal to the goodwill associated with the acquisition premium continues to be reflected in the equity balance. MEPN stated that an adjustment for any alleged goodwill would be unwarranted and arbitrary. (MEPN 7-R, pp.2-3).

MEPN contended that their recommended capital structure does not attempt to recover the acquisition premium through rates. They noted that when the Commission approved the merger, the Commission did not address determination of the Companies' capital structure for ratemaking purposes nor did the Commission address the appropriate ratemaking treatment of any modifications or adjustments to the capital component due to merger accounting. Therefore, MEPN concluded that their proposed capital structure does not violate the Commission order prohibiting recovery of an acquisition premium through rates. (MEPN 7-R, at 3-4).

MEPN also argued in rebuttal that imputing portions of FirstEnergy's merger acquisition debt to MEPN is entirely appropriate because FirstEnergy used that debt to pay for the assets of the Companies. MEPN also pointed out that the FirstEnergy debt allocated to them was based on ten year and thirty year rates of 4.25% and 4.94%, respectively. These rates are historically among the lowest rates for ten and thirty year debt over the past twenty years. (MEPN 7-R, at 4-6).

2. ALJs' Recommendation

The ALJs recommended adoption of a capital structure of 51% long-term debt and 49% common equity. The ALJs found that all of the Parties agreed that this capital structure is appropriate, and concluded that it was reasonable to adopt it. (R.D. at 121).

In regard to the OTS and the OCA disagreement with the MEPN methodology used to arrive at this capital structure, the ALJs agreed with the OCA and the OTS position and rejected ME's and PN's methodology. The ALJs noted that MEPN stated that their proposed capital structures contain a portion of the FirstEnergy merger acquisition debt. According to the ALJs, a portion of the money that FirstEnergy borrowed to finance the merger represents the premium it paid to acquire GPU. The ALJs reasoned that if ME's and PN's proposed capital structure includes FirstEnergy debt, it would have to include a portion of the money borrowed to pay the acquisition premium for GPU. Therefore, rates based on a capital structure that includes a portion of the money borrowed to pay the acquisition premium would allow recovery of the premium through those rates. The ALJs concluded that ME's and PN's methodology is inconsistent with previous Commission rulings in the Merger Savings Remand Proceeding that the Companies should not collect the acquisition premium in retail rates. (R.D. at 121-122).

B. Cost of Capital

1. Positions of the Parties

MEPN proposed an average effective cost of debt of 6.088% for ME and 6.557% for PE (MEPN Exhs. JFP-26 and JFP-27) and weighted average cost of debt of 8.98% for ME and 9.22% for PN. (MEPN St. 7 at 11 and MEPN Exh. JFP-28). According to the Companies, the only substantive dispute concerning the determination of the appropriate weighted average cost of debt relates to the recognition of the actual cost of the FirstEnergy debt that was imputed to MEPN. MEPN argued that recognition of this debt is appropriate because it represents debt issued to pay for the assets of MEPN and the proceeds have assisted FirstEnergy in providing financial support to MEPN. (MEPN St. 7-R, at 4-6).

The OTS proposed a cost of long term debt for ME in this proceeding of 5.10% and 5.83% for PN. (OTS St. 1, at 11-12). The OTS based long term debt on the Companies' contractual obligations for capital used to finance their rate base. These cost rates represent the obligations used to finance the Companies' rate base and are consistent with the obligations of companies of similar size and risk characteristics. The OTS argued that inclusion of any debt that is used for purposes other than the financing of the rate base is inappropriate and must be rejected. The OTS contended that the Companies' proposed debt costs are flawed since they include a proportional share of FirstEnergy's debt that was issued in the acquisition of GPU. As a portion of the Companies' debt cost in this proceeding includes debt used to finance the acquisition of GPU, the OTS averred that its use in this proceeding is inappropriate. (OTS M.B. at 32-33).

The OCA proposed that ME's and PN's costs of debt are actually 5.051% and 5.83% respectively. The OCA argued that the Companies' proposal inflates them to about 6.09% and 6.56%, respectively, because it allocates debt and the cost of parent company debt in its adjusted capital structure. The debt of FirstEnergy, according to the OCA, carries a higher cost rate than either of the Companies' actual embedded cost of debt. (OCA St. 4S at 2). In particular, the FirstEnergy debt reflects FirstEnergy's business and financial risks, including the risks associated with unregulated generation costs. (OCA St. 4S at 6). The OCA contended that the Commission should not impose the FirstEnergy debt cost premium on MEPN customers. The OCA opined that customers should not be required to pay for the higher FirstEnergy cost of debt. (OCA St. 4 at 12). Instead, according to the OCA, the cost of debt should be based on each of the Companies' own cost rate of actual long-term debt on December 31, 2006. (OCA St. 4S at 2) (OCA M.B. at 53-54).

2. ALJs' Recommendation

The ALJs recommended adoption of the OCA position. The ALJs found that MEPN customers should not pay for the higher FirstEnergy cost of debt reflecting FirstEnergy business and financial risks, including the risks associated with unregulated generation costs, nuclear assets and environmental compliance. According to the ALJs, MEPN are regulated entities that do not have risks of this type. The ALJs agreed with the OCA that the cost of debt should be based on each of the Companies' own cost rate of actual long-term debt at December 31, 2006 and, concluded that the MEPN costs of debt are 5.051% and 5.83%, respectively. (R.D. at 123).

3. Exceptions

In its Exceptions, MEPN states that its proposed 51%/49% debt-to-equity capital structure reflects a significant reduction to the equity component of their capital structures, which is the most expensive component of capital. MEPN claims that by reducing the equity, this modified capital structure benefits customers through a lower overall cost of capital. The Companies note that this proposed capital structure was accepted by both the OTS and the OCA, the only parties to address capital structure, and was adopted by the ALJ's. (MEPN Exc. at 31-32).

MEPN states that it derived this modified capital structure by imputing to MEPN an appropriate portion of the Merger acquisition debt incurred by FirstEnergy to pay for the assets of MEPN. MEPN claims that the portion of the FirstEnergy debt allocated to MEPN was based on the percentage of the net Merger purchase price allocated to MEPN, not on the goodwill allocation as erroneously found by the ALJs in FOF No. 204. MEPN also claim that contrary to the erroneous conclusion by the ALJs in FOF No. 206, the imputed debt does not uniformly carry a higher cost rate than the stand-

alone MEPN debt. Rather, according to the Companies, the imputed FirstEnergy debt carries a lower cost rate than some MEPN debt. (MEPN Exc. at 32).

MEPN note that neither the OTS nor the OCA offered an alternative rationale for deriving the favorable capital structure it proposed. Nonetheless, according to the Companies, the ALJs reject the inescapable implications of the only rational basis for deriving the adopted capital structure that appears in the record, and refuse to recognize the associated cost of the imputed FirstEnergy debt. MEPN requests that the Commission correct this error so as to ensure that the logical consequences of the capital structure ratemaking determinations are properly reflected in the end result of this proceeding. (MEPN Exc. at 32-33).

Additionally, MEPN notes that the ALJs accept the arguments of the OTS and the OCA that reflection of the cost of the imputed FirstEnergy debt would somehow violate a Commission prohibition on the recovery of the Merger acquisition premium. MEPN opines that this conclusion is erroneous, as the Commission prohibition was designed to preclude the amortization of goodwill in MEPN's cost of service. MEPN argues that the Commission has never addressed capital structure/cost of debt issues in the context of any rulings on the Merger. Therefore, according to the Companies, because it is not seeking to amortize goodwill in their cost of service, recognition of the cost of the imputed FirstEnergy debt does not violate the prohibition on the recovery of the acquisition premium. (MEPN Exc. at 33).

In reply, the OCA rejoins that the ALJs correctly concluded that FirstEnergy debt should not be included in the cost of debt for MEPN. The OCA avers that the method used by the Companies to reach the debt-to-equity ratio improperly brings goodwill, an accounting concept, into Pennsylvania ratemaking and improperly imposes the merger acquisition premium on ratepayers. The OCA opines that the Companies are incorrect to claim that neither the OCA nor the OTS offers alternative

rationales to the Companies' that would support the 51/49 debt-to-equity capital structure. The OCA states that its witness noted that a 51/49 debt-to-equity capital structure is reasonable in this case because it is similar to the Companies' pre-merger capital structures, the equity ratio is similar to the OCA proxy group, and the ratio is supportive of a strong single A credit rating. (OCA R.Exc. at 20-21).

In regard to the embedded cost of debt, the OCA notes that the Companies' argument in favor of imputing FirstEnergy debt, that reflects total corporate risks, into the capital structures of ME and PN have been demonstrated to be unsound, based upon both contradictory statements and factual errors, and as such should be rejected. The OCA requests that the Commission adopt the ALJs' conclusion that recommends a capital structure of 51/49 debt-to-equity and the use of the actual cost rate of debt for MEPN rather than the inflated cost rate from imputing FirstEnergy debt. (OCA R.Exc. at 21).

The OTS, in its Reply Exceptions, rejoins that the Companies' argument relies heavily on a misguided discussion as to the determination of the capital structure adopted in this proceeding. The OTS avers that it adopted the Companies' proposed capital structure as it was representative of the capital structures routinely found in this industry. OTS claims that at no point did it adopt the Companies' methodology as it has consistently maintained that their claimed hypothetical capital structure is based on the misallocation of debt. The OTS states that the proper capital structure only includes debt that was used to finance the Companies' rate base. Furthermore, the OTS notes that the record clearly indicates that the imputed debt for ME carried a cost rate of 6.45%, which is significantly higher than the 5.051% cost rate determined on a stand-alone basis for ME. Similarly, OTS avers that for PN, the imputed FirstEnergy debt has an issue rate of 7.375% in contrast to the stand-alone debt cost of 5.83%. According to the OTS, these facts indicate that including the misallocated debt from FirstEnergy improperly inflates the appropriate debt cost for MEPN in this proceeding. (OTS R.Exc. at 16-19).

4. Disposition

The resolution of both the appropriate Capital Structure and allowable Cost of Capital rate are dependent upon whether MEPN should be permitted to include a portion of FirstEnergy's merger acquisition debt within its claims in this proceeding. Our review of the record evidence leads us to adopt the recommendation of the ALJs to not allow for the allocation of this acquisition debt to the Companies. As a result, we are in agreement with the ALJs that the Companies proposed 51% long-term debt and 49% common equity capital structure, as agreed to by the OTS and the OCA, is reasonable, but that the Companies' methodology for arriving at this capital structure should be rejected.

Similarly, we are in agreement with the ALJs that the appropriate cost of debt for ME should be 5.051% and the appropriate cost of debt for PN should be 5.83%, which were derived by eliminating the imputed FirstEnergy acquisition debt from the calculations. Specifically, we adopt the position of the OCA that the cost of debt should be based on each of the Companies' own cost rate of actual long-term debt at December 31, 2006.

MEPN have not demonstrated that its proposal to allocate FirstEnergy's acquisition debt to MEPN is appropriate. We are in agreement with the position of the OCA that the Companies' methodology artificially increases the embedded cost of debt component and in agreement with the position of the OTS that only debt used to finance the Companies' rate base is properly included in this proceeding. We reject the contention of the Companies that its customers should be subjected to the higher FirstEnergy cost of debt which reflects FirstEnergy's business and financial risks associated with unregulated generation costs, nuclear assets and environmental compliance. As noted by the ALJs, MEPN are regulated distribution entities that do not

have risks of this type. Accordingly, the Exceptions of MEPN are denied and the recommendations of the ALJs are adopted.

C. Return on Equity

Although there are various models used to estimate the cost of equity, the Commission favors the Discounted Cash Flow (DCF) Model. The DCF model assumes that the market price of a stock is the present value of the future benefits of holding that stock. These benefits are the future cash flows of holding the stock, i.e., the dividends paid and the proceeds from the ultimate sale of the stock. Because dollars received in the future are worth less than dollars received today, the cash flow must be “discounted” back to the present value at the investor’s rate of return.

The following table summarizes the cost of common equity claims made, and methodologies used, by the Parties in this proceeding.

Methodology	MEPN	OCA (5)	OTS (6)
DCF	9.3 to 10.3 (1)	9.6 to 10.1	9.5 to 10.0
CAPM/ECAPM	10.8 to 12.5 (2)	n/a	n/a
CAPM/	n/a	9.2 to 11.0	n/a
Range Recommendion	11.5 to 12.25 (3)	9.6 to 10.1	9.5 to 10.0
Point Recommendation	12.0 (4)	9.7	9.75

- (1)** MEPN St. No. 8, Table MJV-7, MEPN M.B. at 71.
- (2)** MEPN St. No. 8 at 55, 62.
- (3)** MEPN St. No. 8 at 64.
- (4)** MEPN St. No. 8 at 63.
- (5)** OCA St. No. 4 at 4-6.
- (6)** OTS St. No. 1 at 27.

1. Positions of the Parties

MEPN proposed a return on equity of 12.0% for both Companies as just and reasonable. (MEPN St. 8, at 62-63). The Companies used the Capital Asset Pricing Model (CAPM) combined with the Empirical Capital Asset Pricing Model (ECAPM) to calculate a return on common equity. (ME/PE St. 8, at 22-27). The Companies advocated what their witness terms a Market Risk Premium of 6.5%-8.0% as an adjustment. This represents the risk that investors take by investing in stocks instead of risk-free Treasury bills. (ME/PE St. 8 at 28-30). The Companies argued that because of this greater risk, the Commission should allow a higher return on equity.

The Companies also advocated an adjustment to recognize financial risk. The underlying principle is that an equity investor intrinsically faces increased financial risk as the proportion of debt used to finance an investment increases. MEPN stated that applying this principle to determine the cost of equity involves two steps: (1) determine a market-derived overall cost of capital for a proxy group of companies of comparable business risk; and (2) use that overall cost of capital to derive the subject company's cost of equity by substituting its regulatory capital structure in the equation. According to MEPN, the two steps together recognize both business and financial risk and bring the Companies' cost of equity to a level that represents the rate of return that investors could expect to earn elsewhere without bearing more risk. (MEPN St. 8-R at 38).

The OCA used a cost of common equity analysis in which it relies on the Discounted Cash Flow (DCF) methodology, checked by a CAPM analysis, to recommend a 9.7% return on common equity for each company. When combined with its recommendation on capital structure and cost of debt, this produces an overall rate of return of 7.33% and 7.72% for MEPN, respectively. According to the OCA, the Commission has stated on numerous occasions that it prefers using the DCF method. The OCA admits that its recommendation is at the low end of the reasonable range

because of what it characterizes as ME's and PN's ongoing service problems that affect customers. (OCA St. 4 at 5).

To estimate the cost of equity, the OCA used a proxy group of similar companies, because as wholly-owned subsidiaries of FirstEnergy without publicly-traded stock, the market valuations for MEPN are unknown. (OCA St. 4 at 18). The OCA selected eight companies for its proxy group that: (1) are located in the Mid-Atlantic or Northeast; (2) are members of Regional Transmission Organizations; and (3) have divested most or all of their generation assets, thus operating primarily as delivery service utilities. (OCA St. 4 at 19 & Sch. MIK-3). According to the OCA, the capital structures of this group are similar to that of the Companies, and the average common equity ratio for the OCA's proxy group is 44.6%, a close match to the 49% that is being used for the Companies. (OCA St. 4 at 19, 20 & Sch. MIK-3).

Regarding the dividend yield (D_0/P_0) component in the DCF analysis, the OCA used a 4.9% DCF adjusted yield, based upon the 4.79% dividend yield of the proxy group of similar companies and assuming a half-year growth of 2.5% and a full year growth of 5%. (OCA St. 4 at 21).

Regarding the estimate for the growth rate (g) component of the DCF analysis, the OCA averaged the latest data for its group of proxy companies from four well-known sources of projected earnings growth rates, First Call, Zacks, Standard & Poors (S&P) and Value Line. (OCA St. 4 at 22-23 & Sch. MIK-5). This average of 5.19% represents the upper end of the OCA's growth rate, where the median five year growth rate for the group is 4.7% and the average was artificially inflated by growth rates of 10-11% of one company with a history of slow growth. (OCA St. 4 at 23 and Sch. MIK-5). The OCA's analysis determined that the DCF for its proxy group should result in a cost of equity in the range of 9.6% to 10.1% with a midpoint of 9.85%. (OCA St. 4 at 24).

Based on the above analyses, the OCA found a range for a return on equity of 9.6% to 10.1%. (OCA St. 4 at 24 & Sch. MIK-5). The OCA recommended a return on equity of 9.7% for each of the Companies, at the low end of the reasonable range, due to the Companies' ongoing service quality problems that affect ratepayers. (OCA St. 4 at 5). The OCA contended that MEPN have a long history of failing to achieve reliability standards. In support of its contention, the OCA referred to the Commission's investigation into this issue. *Investigation Regarding the Metropolitan Edison Co., Pennsylvania Electric Co., and Pennsylvania Power Co.'s Reliability Performance*, Docket No. I-00040102 (Order entered November 4, 2004). The OCA pointed out that the Companies have not yet fully achieved the agreed upon standards for reliability or key customer service metrics set forth in the settlement of that proceeding. The OCA concluded that because the Companies have failed to achieve reliability and service quality standards consistent with their obligations, their failure should be recognized in the rate of return.

The OTS also employed the DCF methodology to calculate the cost of common equity. The OTS recommended a 9.75% cost of common equity for MEPN as calculated by the application of the market based DCF. This leads to an overall rate of return of 7.38% for ME and 7.75% for PN. The OTS asserted that this methodology has traditionally been endorsed by this Commission and its continued use is warranted in this proceeding. To properly compute the components of the DCF method, the OTS utilized current, historical and forecasted market data for three different entities. (OTS St. 1).

The OSBA did not perform any calculation to arrive at a cost of equity recommendation. Rather, the OSBA advocated the recommendations of either the OTS or the OCA, given both Companies' poor reliability performance. Like the OCA, the OSBA refers to the Commission reliability investigation at Docket No. I-00040102. The

OSBA asserted that both MEPN have failed to achieve the level of performance to which they agreed in the settlement of the investigation. (OSBA St.1)

The OCA, the OSBA and the OTS all objected to the adjustments advocated by MEPN to recognize financial risk.

The Companies rejected the positions of the other Parties asserting that alleged reliability deficiencies should reduce the return on equity. The Companies argued that their reliability is improving. (ME/PE St. 18R (Revised) at 19-21). The Companies also asserted that they have expended significant amounts to improve overall reliability. The Companies contended that reducing the return on equity on this basis would be counter-productive because it would reduce the dollars available to the Companies to fund reliability improvements and perform maintenance functions.

2. ALJs' Recommendation

The ALJs recommended adoption of the OCA's position. The ALJs noted that while other methods can be used as a check on the results arrived at by use of the DCF method, the Commission has long favored use of the DCF method, tempered by informed judgment. The ALJs referenced the Commission Order at *PA Public Utility Commission v. Pennsylvania-American Water Co.*, Docket No. R-00016339, (Order entered January 25, 2002), as support for this position. Additionally, the ALJs stated that because of its strengths, and with its weaknesses ameliorated by informed judgment, primary reliance on the DCF method by the Commission is in the public interest. (R.D. at 125-127).

Furthermore, the ALJs found that MEPN have been unable to achieve reliability standards. The ALJs agreed with the Parties that the Companies have failed to achieve reliability and service quality standards consistent with their obligations and this

should be reflected in the approved rate of return. As a result, the ALJs recommended that the MEPN returns on equity should be 9.7%. (R.D. at 128-129).

Based upon the testimony and evidence of record, the ALJs recommended the following overall rate of return for each Company:

ME

Capital Type	Percent of total cost (%)	Cost Rate (%)	Weighted Cost (%)
Long-term Debt & Allocation Of Parent Debt	51	5.051	2.58
Preferred Stock	0	0	0
Common Equity	49	9.7	4.75
<i>Total</i>	<i>100</i>		<i>7.33</i>

PN

Capital Type	Percent of total cost (%)	Cost Rate (%)	Weighted Cost (%)
Long-term Debt & Allocation Of Parent Debt	51	5.83	2.97
Preferred Stock	0	0	0
Common Equity	49	9.7	4.75
<i>Total</i>	<i>100</i>		<i>7.72</i>

3. Exceptions

In its Exceptions, MEPN argues that the 9.7% return on equity recommended by the ALJ is 100 basis points lower than the return on equity deemed reasonable two years ago for another electric utility in Pennsylvania in *Pa. PUC v. Pennsylvania Power and Light*, Docket No. R-00049255 (Order entered December 22, 2004). This is so even though interest rates have increased since that time, opines the Companies. MEPN states that the ALJs' recommendation is inadequate and unreasonable due to several significant errors. MEPN notes that the ALJs failed to

recognize the impact of financial risk, failed to recognize that MEPN's business risk is greater than that of the proxy group because of the burden imposed by their POLR responsibility, failed to give any consideration whatsoever to alternative analyses such as risk premium or CAPM, failed to reflect application of informed judgment and improperly reduced the allowed return based on alleged poor reliability. MEPN avers that application of Commission precedent to the facts here warrants a move upward from the market derived baseline cost of equity to reflect financial risk, increased business risk and consideration of alternative analysis and informed judgment. (MEPN Exc. at 33-37).

MEPN states that the reduction in allowed return based on alleged poor reliability is improper. The Companies aver that the ALJs erroneously stated that they missed 2005 reliability targets by 70-100 minutes (R.D. at 230) because that target is a comparison to a goal set by the Reliability Settlement for year end 2007, not 2005. MEPN avers that they are, in fact, trending to meet that goal, having already spent \$282 million on reliability improvements in 2005. Also, MEPN notes that the ALJs fail to consider properly the evidence in MEPN's Joint 2nd Quarter Service Reliability Report²¹ that shows that reliability is improving. Additionally, MEPN avers that in 2005, they met 95% of the requirements of the Reliability Settlement.²² As further evidence of improved reliability, the Companies claim that ME has experienced a 53% reduction in service quality complaints and PN has realized a 44% reduction.²³ MEPN rejoins that reducing their rate of return based on a flawed perception of poor performance will only impair their ability to continue reliability related spending. They request that the better approach is to follow the process already agreed upon in the Reliability Settlement. (MEPN Exc. at 37).

²¹ OCA Cross Exh. 8, App A.

²² MEPN St. 18-R (Revised).

²³ MEPN MB at 72.

In reply, the OCA rejoins that the Companies arguments are without merit. First, the OCA avers that its witness demonstrated that the Companies proposed financial risk adjustment is a conceptual argument that may only be valid in a non-regulated setting. The OCA also notes that even if the concept were to be considered valid, the overall business and financial risk of the proxy group on average is very close to that of the Companies in this case, so that no adjustment would be necessary. Second, the OCA refers to the Companies argument that their greater business risk compared to the proxy group should be recognized and increase the ROE allowance by 25 basis points. The OCA avers that the Companies failed to develop this issue on the record and have failed to show that they have any above-average risk pertaining to their distribution service as compared to the proxy group. As a result, the OCA opines it must be rejected as wholly unsupported by the evidence. (OCA R.Exc. at 21-24).

Furthermore, the OCA notes that the Companies arguments that the ALJs erred by reducing the cost of equity based upon poor reliability are incorrect. First, the OCA notes that this will not affect reliability related spending as these dollars are expense dollars that are fully reflected, without adjustment, in the Companies revenue requirement. Second, the OCA avers that the ALJs did not reduce the ROE but found that the lower end of the range of reasonableness was more appropriate. Third, the OCA claims that the Companies failed to meet service quality thresholds set forth in settlement. It points out that both MEPN failed to achieve actual year-end 2005 SAIDI that were required by the Settlement, and instead recorded SAIDI measurements that indicated worsening reliability. The OCA requests that the ALJs' recommendation for a ROE set at the lower end of the reasonable range should be adopted by the Commission. (OCA R.Exc. at 24-25).

The OTS replies that the Companies' Exceptions lack foundation in the record and should be dismissed. The OTS avers that the Companies mistakenly believe that a prior Commission decision has somehow established the minimum return on equity

allowance for the entire industry. The OTS avers this error is further exacerbated by an unsupported claim with respect to interest rates and their relative impact on the calculation of a return on common equity allowance. According to the OTS, it is a well established axiom that utility regulation in Pennsylvania is based on the facts of a specific proceeding and that precedent merely establishes a benchmark as to the regulatory treatment of a particular issue, it does not create a specific standard upon which all subsequent cases must depend. Additionally, the Companies statement concerning interest rates is unsupported in the record and is faulty as the OTS witness testified that long term bond rates are at historic low levels and are expected to remain relatively stable. (OTS R.Exc. at 19-20).

Next, the OTS states that the Commission's long-standing acceptance of the DCF method as the preferred method of determining an appropriate return on equity is not disputed in this proceeding. The OTS explains that the DCF method takes into account several factors in the determination of the fair rate of return: (1) preferences of investors; (2) equity financing; (3) risk; and (4) inflation. It opines that the Companies' myriad of adders and adjustments are unnecessary as the DCF method inherently accounts for these influences in its determination. According to the OTS, additional adjustments to a properly calculated equity allowance based on the DCF method would result in certain economic factors being counted twice which is improper and should be rejected. (OTS R.Exc. at 20-22).

The OTS further rejoins that the Companies' Exceptions mischaracterize the Recommended Decision with respect to the role of reported poor reliability in the rate of return calculation. Contrary to the Companies' erroneous assertion that its rate of return was reduced, the ALJs properly determined that the rate of return calculation must include consideration of the reliability shortcomings of the Companies. There was no stated reduction to the DCF findings per the Companies, as the ALJs' resulting recommendation remained within the range of DCF results calculated by the intervening

Parties. OTS avers that the higher end of the calculated results is simply not warranted based on the record in this proceeding. (OTS R.Exc. at 22-23).

The OSBA also replies that the ALJs did not err in reducing ME's and PN's rate of return based on their poor reliability. The OSBA avers that despite the Companies' effort to portray their reliability in a favorable light, both Companies' reliability has been, and continues to be, far below adequate. The OSBA notes that both Companies' SAIDI scores are worse now than they are required to be at year-end 2007, that ME's SAIDI score is worse now than it was at year-end 2003, that ME does not meet the Commission standard for SAIDI, that both Companies' SAIFI scores are worse than the Commission standard and benchmark and that both Companies' CAIDI scores do not meet the Commission benchmark. Despite these shortcomings, the OSBA notes that the Companies are advocating upward adjustments in the calculated DCF results to reflect claimed financial and business risks. The OSBA opines that it would be inconsistent to approve any upward adjustments to compensate stockholders when the Companies' ratepayers have been forced to accept inadequate service. (OSBA R.Exc. at 8-10).

4. Disposition

As noted previously, we have primarily relied upon the DCF methodology in arriving at our determination of the proper cost of common equity. However, we agree with the ALJs' statement that other methodologies can be used as a check on the reasonableness of the results arrived at by the use of the DCF method, tempered by informed judgment. We note that both the Companies and the OCA have done so in the instant proceeding. We will also use the results of the CAPM and ECAPM methods as a check of the reasonableness of our DCF derived equity return calculation.

Based upon our analysis and review of the record evidence, the Recommended Decision and the Exceptions and Replies thereto, we reject the ALJs'

recommendation to adopt the low end of the OCA's unadjusted DCF return of 9.7%. We note that the OCA recommended a return on equity range from 9.6% to 10.1%, but utilized a point near the lower end of the range due to the Companies ongoing service quality problems. While we acknowledge that the Companies have experienced reliability problems in the past and have been subject to a Commission investigation, we do not agree with the ALJs that it is necessary to reflect this situation by going to the lower end range of equity return.

Other factors must be considered in this proceeding. Based upon the evidence of record, we find that the OCA's recommended range of reasonableness from 9.6% to 10.1% is appropriate. We conclude that within that range, a cost of common equity of 10.1% is reasonable and appropriate to incorporate into our return determinations under the circumstances of this proceeding. This recommendation is based upon the high end of the OCA recommended range of reasonableness giving deference to the business risk faced by the Companies under the current electric industry environment and to the cost of equity results from the other methodologies, as well as recent Commission precedent. We note that the OTS recommended a range of reasonableness from 9.5% to 10.0% based upon the DCF methodology. The Companies DCF calculations, adjusted to remove their financial risk adders, resulted in a range of reasonableness from 9.3% to 10.3%. Also, the OCA calculated the range of reasonableness based on the CAPM methodology from 9.2% to 11.0%, while the Companies CAPM calculations indicated a range from 10.8% to 12.5%. Based upon these findings, we are of the opinion that an equity return of 10.1% is reasonable.

Accordingly, the Exceptions of MEPN are granted, in part, and denied, in part, to the extent consistent with the foregoing discussion.

The following table summarizes our determinations concerning the Companies' capital structure, cost of debt and cost of common equity, as well as the resulting weighted costs and overall rate of return:

ME			
Capital Structure	Ratio	Cost Rate	Weighted Cost
	(%)	(%)	(%)
Debt	51.00	5.051	2.58
Common Equity	49.00	10.1	4.95
	100.00		7.53

PN	Ratio	Cost Rate	Weighted Cost
	(%)	(%)	(%)
Capital Structure			
Debt	51.00	5.83	2.97
Common Equity	49.00	10.1	4.95
	100.00		7.92

X. COST OF SERVICE

A. ALJs' Interpretation of *Lloyd v. Pa. PUC*, 904 A.2d 1010 (Pa. Cmwlth. 2006), Petitions for Allowance of Appeal Pending

1. Positions of the Parties

The Companies submitted unbundled cost of service studies (COSS) based on data gathering systems (AM/FM, CREWS) and analytics (TACOS Gold) that allocate generation, transmission, and distribution system costs to establish a revenue requirement for each customer rate schedule. (MEPN M.B. at 77; MEPN St. 5 at 4; MEPN St. 5-R at 6-7). MEPN claims that this is consistent with the Commonwealth Court's determination in *Lloyd v. Pa. PUC*, 904 A.2d 1010 (Pa. Cmwlth. 2006), petitions for allowance of

appeal pending, which requires that in this new era of unbundled generation, transmission and distribution services, rates must be set primarily based on a COSS. (MEPN M.B. at 77).

The Companies argued that because the statutory generation rate cap period has expired, latitude in generation cost allocation is permitted pursuant to Section 2804(4) of the Code, 66 Pa. C.S. § 2804(4). (MEPN M.B. at 78; MEPN Sts. 5-R at 13-15). MEPN proposed allocating generation costs to customer rate schedules by using three year average, historic LMPs weighted by customer consumption data. (MEPN M.B. at 77; MEPN Sts. 5 at 6). The Companies claim that allocating 100% of costs on LMP is a superior method for tracking cost causation as it recognizes which customers use more load in expensive LMP hours and which have flatter load shapes. (MEPN Sts. 5-R at 13-15).

MEPN initially proposed allocating transmission costs on a kWh basis, but later concurred with the Industrials and the OSBA that allocation of these expenses on a demand/energy basis is more reflective of cost of service. MEPN witness Stein provided a cost allocation of projected transmission costs using demand and energy allocators. (MEPN M.B. at 78; MEPN Exh. EBS-8-R Revised). The Companies opined that transmission costs should be allocated on a demand/energy basis, but that rate design should reflect a uniform kWh rate, by rate schedule, to keep the customers' price to compare easily discernable. (MEPN M.B. at 78; MEPN St. 4 at 22; Tr. at 874).

MEPN stated that its COSS accurately identifies the costs to provide distribution services and should be adopted without adjustment. Distribution plant assets were classified and allocated to primary and secondary customers using a combination of cutting-edge and historically used methods such as a minimum grid study. (MEPN M.B. at 79; MEPN St. 5 at 4, 12). The COSS sub-functionalized certain distribution plant (poles overhead and underground conductors and conduit), and allocated these costs to

three rate schedule groups, primary customers (higher voltage), secondary customers (lower voltage) and primary/secondary (all customers). (MEPN M.B. at 79; MEPN St. 5 at 7, 11).

MEIUG, PICA, and IECPA opined that the Companies' distribution COSS are reasonable and should be adopted. (MEIUG/PICA/IECPA St. 1 at 48).

The OCA opined that a COSS serves as a guide that rates must be set consistent with the principle of cost causation. (OCA M.B. at 62; OCA St. 5 at 14). According to the OCA, other ratemaking principles such as gradualism, rate continuity, simplicity, and public policy goals must be considered in tandem with an accurate and reliable COSS if rates are to be set fairly. (OCA M.B. at 62; OCA St. 5 at 14). The OCA argued that both the Companies' distribution and generation COSSs are flawed. OCA witness Smith stated that the COSSs allocate more distribution costs to secondary service customers and to residential customers than can be justified by cost causation. (OCA St. 5 at 5). Additionally, the OCA contends that not only is the generation COSS flawed in that it fails to allocate generation in a manner that reflects how the Companies incur costs, it is improper pursuant to 66 Pa. C.S. § 2804(4) because generation costs cannot be allocated in this case due to the rate caps. (OCA M.B. at 63).

The OCA argued that MEPN's allocation of distribution costs and revenues understates the cost of serving large customers who take service at primary voltage and thereby overstates the cost of serving residential customers. (OCA M.B. at 63). OCA witness Smith requested that the Companies prepare revised cost of service studies with the following adjustments: (1) increase the portion of accounts 364-367 that is treated as primary service related; and (2) increase the demand-related portion of account 368. (OCA St. 5 at 12). The modified studies showed that the primary classes (GP for Met-Ed and GP and LP for Penelec) would earn much lower rates of return than the Companies' studies showed, and were paying less than the system average rate of return under the

Companies' proposals. (OCA M.B. at 64; OCA St. 5 at 14-15 (Tables ME1 and PN 1)). The OCA recommended that its distribution cost allocation should be adopted, and its proposed revenue requirement allocation should be scaled back across the board, by equal percentage, among all customer classes if the Companies' distribution revenue requirements are modified by the Commission. (OCA M.B. at 69).

The Commercial Group opined that the Companies' new methodology for classifying distribution costs is flawed and inconsistent with the generally accepted *NARUC Electric Utility Cost Allocation Manual*. (CG M.B. at 18). With respect to this classification step for Plant Accounts 364-369, the Companies' witness, Mr. Stein, testified that, "the NARUC manual recommends dividing the mass distribution property (Plant Accounts 364-369) into two components, customer and demand" with the "customer component [being] determined through a minimum grid study which is calculated by pricing the poles [Account 364], conductors [i.e., wires in Accounts 365 and 367 and underground pipe in Account 366], transformers [Account 368] and service drops [Account 369] at the installed cost of the equipment that would at a minimum be required to serve a customer in each of the accounts." (MEPN St. 5 at 12). The Commercial Group points out that this is the way the Companies have historically performed their cost of service studies. (Tr. at 764). The Commercial Group stated that here, the Companies chose not to perform this analysis and instead arbitrarily declared all costs in the secondary distribution sub-function category as demand costs and classified zero costs as customer costs. (CG St. 1 at 24). The Commercial Group argued that not only is the Companies' new method of classifying secondary costs in Accounts 364 to 367 unreasonable, the results obtained are unreasonable as well. In prior cases, the Companies determined that the minimum costs (customer costs) represented 62.7% (Met-Ed) and 72.3% (Penelec) of their cost of poles (Account 364); 39 % (Met-Ed) and 31.1% (Penelec) of wire (Account 365) costs were customer-related; and 66.7% (Met-Ed) and 45.3% (Penelec) of underground wire and conduit costs (Accounts 366-367) were customer-related. MEPN now claims that these costs are wholly attributable to

differences in voltage demand between customers. (CG Exh. KCH-2, CG St. 1 at 28). The Commercial Group rejects MEPN's position that none of those secondary costs are customer-related. (CG Exh. KCH-2, CG St. 1 at 28). (RD at 135-137).

Using the parameters developed by the Companies in their last rate case, CG re-calculated the revenue changes by rate class necessary to achieve the Companies' requested revenue requirements based on the classification of an appropriate share of distribution system costs as customer-related. (CG M.B. at 22). The Commercial Group recommended that any overall rate increase for the four major secondary rate schedules – RS, RT, GS, and GST – be established on an equal percentage basis (in the case of Met-Ed) or be established within a specified bandwidth (in the case of Penelec). *Id.* With respect to Met-Ed, the Commercial Group's witness concluded that the adjusted cost-of-service analysis supports an equal percentage rate increase for the major secondary voltage classes on the Met-Ed system. With respect to Penelec, the Commercial Group's witness concluded that an equal percentage rate increase for the major secondary voltage classes on the Penelec system, with the exception of GS in Penelec, which due to its significantly lower revenue deficiency, warrants a percentage rate change that is 80% of the secondary voltage group as a whole. (CG M.B. at 13).

2. ALJs' Recommendation

The ALJs found that demand/energy transmission cost allocators are appropriate, but that rate design should reflect a uniform kWh rate, by rate schedule to keep the customers' price to compare simpler. (R.D. at 130). The ALJs agreed with the OCA that any changes to generation rates would be in violation of the generation rate caps established pursuant to the 1998 Restructuring Settlement. The ALJs rejected any changes to the design of the generation rates, with or without an increase in the overall generation rates, as inconsistent with the generation rate caps. (R.D. at 132). The ALJs found that MEPN did not meet their burden of proving that their cost of service study

methodology which categorized a small subset of distribution costs as primary costs, and the remaining distribution costs to secondary customers based on voltage peak demand was reasonable. (R.D. at 138). The ALJs recommended the adoption of the Commercial Group's proposed distribution cost allocation methodology shown at Exhibits KCH-2A and 2B as a basis for the increase allocated to rate classes RT, RS, GS, and GST. (R.D. at 139).

3. Exceptions

The OCA argues that to the extent that the ALJs' decision can be read to interpret *Lloyd* in a manner that strictly confines Commission approval of rate setting and design solely to cost of service study results, it is erroneous. (OCA Exc. at 7). The OCA explains that while the *Lloyd* Court held that cost of service is the primary basis for setting rates and rate structures, it also held that there are other factors such as cost causation that should be considered by the Commission when examining rate designs. *Id.*

The OCA submits that each rate element, distribution, transmission, and generation must be evaluated separately according to *Lloyd*. *Id.* The OCA excepts to the ALJs' reliance on exhibits that bundle together the rate elements as contrary to *Lloyd*. (OCA Exc. at 9).

MEPN rejoins that the OCA's Exception regarding the ALJ's interpretation of *Lloyd* should be rejected because the ALJs did not hold that a COSS is the only factor upon which the Commission can establish utility rates. (MEPN R.Exc. at 16). The Commercial Group rejects the OCA's Exceptions regarding the COSS and urges adoption of the RD on this issue. (CG R.Exc. at 3-8). The OSBA replies that the ALJs' recommendations are not based on a misinterpretation of *Lloyd*. (OSBA R.Exc. at 11).

The OCA next argues that the ALJs did not sufficiently articulate how the distribution revenue change should be allocated to the various customer classes. (OCA Exc. at 8). The OCA argues that after adopting the Commercial Group's modification to the distribution cost of service study of the Companies, the ALJs do not clearly recommend any allocation of the distribution rate changes to the various customer classes. *Id.* The OCA states that Conclusion 164 on page 261 of the Recommended Decision could be interpreted as a recommendation that any rate changes be spread in a manner consistent with the Commercial Group Exhibits KCH-2A at 1, l. 17 and KCH-2B, p.1, l. 17. According to the OCA, Line 17 of each of these exhibits represents the total percentage increase that would be needed for each class to provide the precise system average rate of return under the Companies' full revenue requirement increase request, including generation service. (OCA Exc. at 9). The OCA submits that if it was the intent of the ALJs to allocate the distribution revenue change on this basis, such recommendation would be in error, because it includes generation charges.²⁴

The OCA further argues that the allocation of the distribution revenue change to the various customer classes must recognize all elements of the distribution rates – distribution base rates and universal service charges. (OCA Exc. at 11). The OCA submits that the residential rate schedules are providing returns on distribution service that are at or above the system average rate of return under the Companies', the OCA's, and the Commercial Group's cost of service studies. *Id.* The OCA requests that the residential rate schedules receive a percentage rate change that is equal to the percentage change in distribution revenues, inclusive of the universal service revenues. *Id.*

²⁴ It should be noted that Commercial Group's witness, Mr. Higgins, recommended using line 20 of his exhibits for allocation purposes, not line 17 as stated in the Recommended Decision (OCA Exc. at 9, Commercial Group St. 1 at 30).

In reply to the OCA's Exceptions, MEIUG/PICA state that the ALJs correctly determined that the Companies generally presented a reasonable distribution COSS, which should be used to allocate any resulting distribution revenue changes. (MEIUG/PICA R.Exc. at 17). With regard to the OCA's request that the Commission take into consideration the impact of the ALJs' recommendation to allocate USP costs solely to the residential class in any determination regarding distribution rates, MEIUG/PICA cautions against any modification to distribution rates that would result in inappropriate USP cost shifting to other classes. (MEIUG/PICA R.Exc. at 18).

The OSBA states that the required distribution rate change should be calculated on a distribution-only basis and applied to distribution revenues at present rates, excluding universal service costs. (OSBA R.Exc. at 12). The OSBA submits that the ALJs properly denied the OCA's and the Companies' request that universal service costs be recovered from all customer classes. (OSBA R.Exc. at 13).

4. Disposition

The ALJs' did not misinterpret the holding in *Lloyd* with regard to the relationship between COSS and ratemaking. It is clear that the ALJs fully understood *Lloyd's* holding that "rates must be set *primarily* based on COSS." (R.D. at 130) (emphasis added). This statement is in accord with the Commonwealth Court's finding that the cost of providing service is the polestar of ratemaking which trumps other concerns such as gradualism or rate shock. *Lloyd v. Pa. PUC*, 904 A.2d 1010, 1020. The ALJs correctly concluded that the proper interpretation of *Lloyd* is that a COSS is the primary, but not the only, basis for cost allocation for each unbundled element. Accordingly, the OCA's Exception on this issue is denied.

The ALJs allocated transmission costs on a demand/energy basis and recommended a uniform kWh charge for each customer rate schedule. The ALJs adopted

the Commercial Group’s modification for Accounts 364-367 as discussed above. This approach will result in proper transmission cost allocation to the various rate classes, and simultaneously simplify future retail choice decisions for consumers once rate caps are lifted. We will reject the OCA’s proposed modification to the Companies’ distribution COSS as it is inconsistent with the Commercial Group’s revenue allocation and would be a backdoor way to make the GS and GST classes share in the cost of universal service. We note that the ALJs’ decision to more closely follow COSS results is consistent with the *Lloyd* decision. The OCA’s Exceptions on this issue are, therefore, denied.

XI. RATE DESIGN

The ALJs found that there were only a few challenges to the Companies’ proposed rate design. The summaries set forth below are the major rate design changes proposed by MEPN that were unopposed by the Parties. The ALJs recommended that they be accepted without modification. (R.D. at 139). The summaries are those found at Pages 139, 140 and 141 of the Recommended Decision.

A. Metropolitan Edison Company - Unopposed Rate Design Changes

Rate Schedule	Company Proposed Modification	Company Testimony Reference
Rate Schedules Borderline Service, Street Lighting Service, Ornamental Street Lighting Service & Outdoor Lighting Service	Assign Company average rate increase to these bundled services	Met-Ed Exhibit GRP-2. New rates included in schedules – not specifically addressed in testimony
Traffic Signal & Telephone Lighting Service	Eliminate – move customers to GS-fixed usage rate	Met-Ed Statement No. 6 p. 44, line 20
Fire Alarm Box Lighting Service	Eliminate – move customers to GS-fixed usage rate	Met-Ed Statement No. 6 p. 45, line 15
Rate GS-Small	Include a fixed-usage provision	Met-Ed Statement No. 6 p. 39, line 7
Rate RT – Provision D - Solar Water Heating	Restrict	Met-Ed Statement No. 6 p. 35, line 17

Rate GS – General Provisions D – Churches and Parochial Schools, E- General Heating, Cooking and Air Conditioning, G- Time of Day Service under 10 kW, & H – Time of Day Service Greater than 10 kW	Eliminate	Met-Ed Statement No. 6 p. 39, line 16 (Prov D only) Also Met-Ed GRP-7
Rate GP – General Provision A – Voltage Discount – 34.5 kV or Greater	Eliminate	Met-Ed Statement No. 6 p. 41, line 22
Rate QF – Interruptible Backup provision	Eliminate	Met-Ed Statement No. 6 p. 31, line 8
Rate MS – General Provisions A – Space Heating and B – Church-Operated Schools	Eliminate	Met-Ed Statement No. 6 p. 41, line 9

B. Pennsylvania Electric Company - Unopposed Rate Design Changes

Rate Schedule	Company Proposed Modification	Company Testimony Reference
Rate Schedules Borderline Service, High Pressure Sodium Vapor Street Lighting Service, Municipal Street Lighting Service, Outdoor Lighting Service	Assign Company average rate increase to these bundled services	Penelec Exhibit GRP-2. New rates included in schedules – not specifically addressed in testimony
Traffic Signal Service	Eliminate – move customers to GS-fixed usage rate	Penelec Statement No. 6 p.41, line 20
Rate GS-Small	Include a fixed-usage provision	Penelec Statement No. 6 p. 36, line 15
Rate GS-Large	Restrict Off-Peak Thermal Storage provision	Penelec Statement No. 6 p. 38, line 21

Rate GS – General Provisions – D Service to Schools and Churches, E-General Heating, Cooking and Air Conditioning, G-Off-Peak Water Heating Service, H- Service to Churches	Eliminate	Penelec Statement No. 6 p. 37, line 1 (Prov D only) Also Penelec GRP-7
Rate GP – General Provisions A- Service to Schools and Churches, B- Multi-Point Delivery, and C – Transformed Service	Eliminate	Penelec GRP-7
Rate QF – Interruptible Backup provision	Eliminate	Penelec Statement No. 6 p. 30, line 11
Rate RT – Provision D - Solar Water Heating	Restrict	Penelec Statement No. 6 p. 34, line 22

The ALJs stated:

Met-Ed and Penelec allege that their rate design is based on the cost of service study (COSS) for generation and distribution rates, with minor deviations. The transmission rates contain the kWh and demand allocators reflected in Met-Ed and Penelec's oral rejoinder testimony. Those rates and allocators will be included in the TSC Rider.

(R.D. at 141).

1. Disposition

No Party filed Exceptions to the ALJs' recommendations on this issue. Finding the ALJs' recommendation to be reasonable, appropriate, and in accordance with the record evidence, it is adopted.

C. Disputed Rate Design Issues

1. Rates RS and RT

a. Positions of the Parties

The Companies proposed an increase in the customer charge for Schedules RS and RT. The Companies asserted that the increases are consistent with the COSS results. The Companies also proposed shifting the time differential in distribution rates, arguing that the shift is consistent with their over-all rate design approach because investment in the distribution system is not dependent on time of energy use. Also, ME argued that its proposed fixed distribution charge for Schedules RS and RT is similar to other utilities in Pennsylvania. (R.D. at 141).

OCA objected to the Companies' proposal to increase residential customer charges and lower the per kWh charges to increase revenues through fixed charges. OCA stated that the ME proposed increase for the RS customer charge is a 25.5% increase

while ME is simultaneously proposing a decrease in its distribution rate. OCA also stated that PE's proposed customer charge will increase 24.5% while the distribution rate will only increase by 6%. According to the OCA, this change in rate design will result in small residential customers on ME's system receiving an overall increase in distribution charges while large customers will receive a decrease. OCA asserts that for PE's system, small customers will receive a much larger increase than large customers. OCA proposes that residential customer charges should not be changed and any additional revenue for residential classes should be obtained through the per kWh charges. (R.D. at 142).

OCA also opposed the Companies' proposal to eliminate existing time-of-day rate differentials in the distribution portion of the rate for residential time of day rate schedules RT. Elimination of time-of-day rates will eliminate any incentive for customers on that rate to manage their load. Also, customers will lose the opportunity to benefit from conserving at peak hours since Schedule RT has a flat generation charge. OCA also argued that customers would lose the ability to budget and exert control over the amount of their bills. (R.D. at 142).

b. ALJs' Recommendation

The ALJs recommended that the Companies proposal for Rates RS and RT be accepted. They determined that the increases are "fully consistent with COSS results." (R.D. at 142). The ALJs also found that shifting the time differential in distribution rates to generation rates is consistent with *Lloyd v. Pa. PUC*, 904 A.2d 1010 (Pa. Cmwlth. 2006), because investment in the distribution system is not dependent on time of energy use. The ALJs determined that while OCA may have been correct that the changes could affect conservation and usage by customers, those issues were generation related and not distribution issues. The ALJs stated that *Lloyd* requires that each unbundled element of service must support itself and shifting the time differential is consistent with that concept. (*Id.* at 143).

c. Exceptions

In its Exception No. 5, OCA argues that the ALJs erred by recommending approval of the increase to customer charges. OCA asserts that the ALJs' recommendation is not supported by their statement that the increases are consistent with COSS results. According to OCA, "customer charges should be based only upon basic and direct consumer costs, such as those associated with meters, meter reading, billing and collection costs." (OCA Exc. at 12). (Citation omitted). OCA argues that this basic customer cost standard has been applied to several major electric utilities and that standard should be maintained here. *Id.*

OCA asserts that the Companies have made no showing that their direct customer costs exceed the current customer charge. Accordingly, there should be no increase in those charges. (OCA Exc. at 12). OCA also states that the Companies justify their proposed increases with a general statement that the increased customer charges would be comparable to other utilities in Pennsylvania. However, OCA argues that the Companies also opined that each utility's cost and cost studies are unique. *Id.* OCA also asserts that it is inappropriate to provide for an increase in customer charges while overall distribution rates decrease. (OCA Exc. at 13).

OCA's Exception No. 6 claims error in the ALJs' recommendation to accept the Companies' proposal to shift the time differential from distribution rates to generation. OCA argues that such a shift will disturb the generation rate design established in the Restructuring Settlement and violate the generation rate cap. OCA notes that the ALJs refused to recommend approval of changes to the generation rate design when they rejected seasonal rates. OCA argues that the same result should occur here in the context of time of use rates. OCA asserts that "the flat generation rate for

Rate RT, with the on-peak/off-peak charges for distribution and competitive transition charges, must remain during the rate cap period.” (OCA Exc. at 14).

The Companies respond to OCA’s Exception No. 5 and argue that regardless of whether there is an overall distribution rate decrease, that is irrelevant to whether there should be an increase to the customer charge. The Companies disagree with OCA’s argument that the increase in customer charges is not supported by COSS or that it violates the principle that such costs should reflect certain basic customer services. The Companies argue that the “COSS clearly shows the fixed costs associated with meters, meter reading, billing and collection, etc., justify even *larger increases* in the customer charges” than those proposed. (Companies R.Exc. at 17-18). The Companies also assert that the proposed increases are not solely based upon a comparison with other utilities. That comparison was only one factor in supporting the design. (*Id.* at 18).

The Companies’ response to OCA’s Exception No. 6 asserts that the proposal to shift the time differential from distribution to generation does not violate the rate cap provisions of the Restructuring Settlement. The Companies argue that since the statutory rate cap has expired, the Commission has more discretion regarding the rate cap imposed by the Restructuring Settlement. Also, the rate cap applies to “customers” in the aggregate, not individual customers. According to the Companies, the generation rate cap applies to each specific rate class. The Companies argue that this is consistent with the Act’s provisions which provide authority to the Commission to approve flexible pricing and flexible rates (Sections 2806(h) and 2804(2) of the Code, 66 Pa. C.S. §§ 2806(h) and 2804(2)). The Companies assert that introduction of the time of date differentials into the residential generation rates do not result in an increase in the rates charged to the rate classes in the aggregate. (Companies R.Exc. at 19-20).

d. Disposition

OCA's Exception No. 5 is denied. The ALJs determined that the Companies' proposal is fully consistent with the COSS put forward in this case. As noted by the Companies in their Reply Exceptions, the record clearly supports an increase in customer charges based upon COSS elements which include basic customer services such as meters, meter reading, billing and collection. (Companies R.Exc. at 127). OCA's suggestion that the only support advanced for the customer charge increase in Rate RS is a comparison to other utilities in the Commonwealth is not borne out by the record, nor the ALJs' determination.

We will also deny OCA's Exception No. 6 regarding moving the time differential from distribution to generation. As noted by the ALJs, the shift is consistent with *Lloyd's* requirement that unbundled services must stand on their own. The time differential is a generation issue, not distribution. This is made even clearer by OCA's arguments regarding conservation and usage which are obvious generation-related concerns.

2. Rates GS and GST

a. Positions of the Parties

The Companies and OTS agreed that the customer charge for rate GS should be \$21.52 per month, and that any revenue shortfall should be collected through the distribution demand charge on a per kW basis. ME and OTS also agreed to maintain the GST fixed distribution charge at \$60.98 per month. Any excess revenue generated by that change would be credited to the GS distribution demand charge. PE and OTS agreed to maintain the current customer charge of \$60.98 per month for rate GST. Any excess revenue will be credited to the distribution demand charge in rate GST. PE advocated a distribution demand charge of \$7.78 per kW. OTS argued that was too high, producing a

rate of return for the GST class of 10.42%, which is well above the system average rate of return of 9.23%. OTS argued that the GST distribution demand charge should be \$7.40 per kWh. PE argued that was not high enough.

b. ALJs' Recommendation

The ALJs recommended adoption of rates as agreed to by the Companies and OTS. With regard to PE's distribution demand charge in Schedule GS, the ALJs recommended adoption of PE's proposed \$7.78 per kW. The ALJs found that this charge "is more consistent with COSS than any other proposal. We do not see the 10.42% rate of return to be either excessive or unreasonably high compared to the system average of 9.23%." (R.D. at 144).

c. Exceptions

OTS' Exception No. 1 claims error in the ALJs' recommendation to adopt PE's proposed distribution demand charge of \$7.78 per kW in Schedule GS. OTS reiterates its argument that the demand rate should be lower "because the rate of return for the GST class under the Company proposed rates is 10.42%, which is well above the system average of 9.23%." (OTS Exc. at 4). OTS asserts that the ALJs' determination that the class rate of return is not excessive is inconsistent with their finding that *Lloyd* requires that rates must be set primarily based upon COSS. Given the excessive return produced by the Companies' proposal, OTS asserts that its proposal of \$7.40 per kW "would clearly bring the rates closer to the cost of service." Accordingly, OTS argues that its proposal should be adopted. (*Id.* at 5).

d. Disposition

OTS Exception No. 1 primarily uses the system average rate of return as a gauge to suggest that PE's proposed demand charge for Rate GST is too high. However, as found by the ALJs, the proposed demand charge of \$7.78 per kW for Rate GST "is more consistent with COSS than any other proposal." We agree. The primary focus on this issue is the COSS. *Lloyd*. While comparisons of system average rate of return to a rate class rate of return may be instructive and signal problems, the driver on this issue is COSS. With the record showing that PE's proposed \$7.78 per kW is more consistent with COSS than any other proposal, we will deny OTS' Exception No. 1. In our view, *Lloyd* would permit use of a rate of return comparison if the issue was close or the record presented a confusing picture. However, that is not the case here.

3. Eight Hour on-Peak Time of Day Option (ME)

ME proposed to eliminate this provision and change it to a twelve hour on-peak period on the basis that it is not consistent with PJM's 16 hour on-peak period or cost causation principles. ME also asserted that the eight hour time period insulated customers from the true wholesale price of energy. (R.D. at 144). MEIUG/PICA and Sheppard challenged ME's proposal. (R.D. at 145-147).

The ALJs recommend rejection of ME's proposal on the basis that ME had failed to show that the revision was just and reasonable. (R.D. at 147).

a. Disposition

No exceptions have been filed to this determination. Finding the ALJs' recommendation to be reasonable, appropriate and in accordance with the record evidence, it is adopted.

4. Rates GP and LP

PE and OTS agreed to hold the fixed distribution charge increase for these schedules to 30%, with any revenue shortfall to be reflected in the distribution demand charge for these rate schedules. The GP customer charge should be \$277.50 for primary service and \$82.00 per month for qualifying service and the LP customer charge should be \$991.00 per month. The ALJs recommended adoption of the Parties' agreement.

a. Disposition

No exceptions have been filed to this determination. Finding the ALJs' recommendation to be reasonable, appropriate and in accordance with the record evidence, it is adopted.

XII. Tariff Provisions

A. Metropolitan Edison Company Unopposed Tariff Changes

Company Proposed Modification	Proposed Tariff Reference	Company Testimony Reference
Insulation Requirements – Update/clarify standards	Rule 8	Met-Ed Statement No. 6, P. 19, L. 14 through P. 21, L.4
Modification/Clarification of when customer is entitled to historic billing information at no charge	Rule 12 a.(2)	Met-Ed Statement No. 6, P. 21, L. 6 through L.21
Seasonal Billing – Restricted and terminate	Rule 12 b.(10)	Met-Ed Statement No. 6, P. 22, L. 15 through, P. 23, L.15
Advanced Payment Billing – Restricted and terminate	Rule 12 b.(11)	Met-Ed Statement No. 6, P. 23, L. 17 through, P. 24, L.16

Due Date for Bills – Extend the due date for customers 60 years of age or older who receive Social Security or similar pension benefits	Rule 13 a.	Met-Ed Statement No. 6, P. 24, L. 18 through P. 25, L.12
Conditional Power Service – Terminate the tariff provision		Met-Ed Statement No. 6, P. 26, L. 16 through P. 30, L.11
Backup and Maintenance Service – Eliminate “Interruptible Backup Service” provision	Rule 19 and Rate Schedule QF	Met-Ed Statement No. 6, P. 30, L. 13 through P. 31, L.17
Rate RT – Restrict “Solar Water Heating” provision to existing customers	Rate Schedule RT	Met-Ed Statement No. 6, P. 35, L. 1 through P. 36, L.2
Non-Residential rate schedules minimum charges – Separate charge for full and delivery service customers combined into a single charge	Non-Residential rate schedules	Met-Ed Statement No. 6, P. 36, L. 8 through L.9
Non-Residential rate schedules Off-peak service – Eliminate provision	Non-Residential rate schedules	Met-Ed Statement No. 6, P. 36, L. 10 through L.11
Rate GS Volunteer Fire Company – Separate rate schedule – new	Rate Schedule GS – Volunteer Fire Company	Met-Ed Statement No. 6, P. 38, L. 8 through P. 40, L.6
Rate GS Small – Separate rate schedule – new	Rate Schedule GS – Small	Met-Ed Statement No. 6, P. 38, L. 8 through P. 40, L.6
Rate GS Medium – Separate rate schedule – new	Rate Schedule GS – Medium	Met-Ed Statement No. 6, P. 38, L. 8 through P. 40, L.6
Rate GS “General heating, cooking and air conditioning” provision – Eliminated	Rate Schedule GS – Medium	Met-Ed Statement No. 6, P. 38, L. 10 through L.17
Rate GS Service to Schools and Churches provision - Eliminated	Rate Schedule GS – Medium	Met-Ed Statement No. 6, P. 39, L. 16 through L.18
Rate GST – Renamed to Rate GS Large	Rate Schedule GS – Large	Met-Ed Statement No. 6, P. 40, L. 8 through L.19

Rate MS “Space Heating Restricted” provision - Eliminated	Rate Schedule MS	Met-Ed Statement No. 6, P. 40, L. 21 through P. 41, L.16
Rate GP Voltage discount provision – Eliminate for customers taking service from the 34.5 kV wye configuration	Rate Schedule GP	Met-Ed Statement No. 6, P. 41, L.1 8 through P. 42, L.4
Private Outdoor Lighting Service – Restrict to existing customers and phase out	Outdoor Lighting Service	Met-Ed Statement No. 6, P. 42, L. 6 through P. 44, L.12
Traffic Signal and Telephone Booth Lighting Service – Eliminate schedule and serve customers under Rate GS-Small	Rate Schedule GS – Small	Met-Ed Statement No. 6, P. 44, L. 14 through P. 45, L.7
Fire Alarm Box Lighting Service – Eliminate schedule and serve customers under Rate GS-Small	Rate Schedule GS – Small	Met-Ed Statement No. 6, P. 45, L. 9 through , P. 46, L.2
CTC and Generation Charges Rider – Eliminate and include in applicable rate schedules		Met-Ed Statement No. 6, P. 46, L. 6 through L.22
Curtailable Service Rider – Eliminate		Met-Ed Statement No. 6, P. 46, L. 6 through L.22
Economic Development Rider – Eliminate provisions relating to economic and rename as Short Term Demand Utilization Rider	Rider N Short Term Demand Utilization	Met-Ed Statement No. 6, P. 46, L. 6 through L.22
Business Development Rider (New and Existing Service Locations) – Eliminate		Met-Ed Statement No. 6, P. 46, L. 6 through L.22
Residential Experimental Time of Use Rider – Eliminate		Met-Ed Statement No. 6, P. 46, L. 6 through L.22
Sustainable Energy Fund Rider – Eliminate		Met-Ed Statement No. 6, P. 47, L. 1 through L.6

B. Pennsylvania Electric Company Unopposed Tariff Changes

Company Proposed Modification	Proposed Tariff Reference	Company Testimony Reference
Insulation Requirements – Update/clarify standards	Rule 8	Penelec Statement No. 6, P. 19, L. 15 through P. 21, L.8
Modification/Clarification of when customer is entitled to historic billing information at no charge	Rule 12 a.(2)	Penelec Statement No. 6, P. 21, L. 10 through P. 22, L.2
Seasonal Billing – Restricted and terminated	Rule 12 b.(10)	Penelec Statement No. 6, P. 22, L. 19 through P. 23, L.19
Due Date for Bills – Extend the due date for customers 60 years of age or older who receive Social Security or similar pension benefits	Rule 13 a.	Penelec Statement No. 6, P. 23, L. 21 through P. 24, L.15
Conditional Power Service – Terminate the tariff provision		Penelec Statement No. 6, P. 25, L. 19 through P. 29, L.14
Backup and Maintenance Service – Eliminate “Interruptible Backup Service” provision	Rule 19 and Rate Schedule QF	Penelec Statement No. 6, P. 29, L. 16 through P. 30, L.21
Rate RT – Restrict “Solar Water Heating” provision to existing customers	Rate Schedule RT	Penelec Statement No. 6, P. 34, L. 6 through P. 35, L.6
Non-Residential rate schedules minimum charges – Separate charge for full and delivery service customers combined into a single charge	Non-Residential rate schedules	Penelec Statement No. 6, P. 35, L. 8 through L.14
Rate GS Volunteer Fire Company – Separate rate schedule – new	Rate Schedule GS – Volunteer Fire Company	Penelec Statement No. 6, P. 35, L. 16 through P. 37, L.14
Rate GS Small – Separate rate schedule – new	Rate Schedule GS – Small	Penelec Statement No. 6, P. 35, L. 16 through P. 37, L.14
Rate GS Medium – Separate rate schedule – new	Rate Schedule GS – Medium	Penelec Statement No. 6, P. 35, L. 16 through P. 37, L.14
Rate GS Service to Schools and Churches provision - Eliminated	Rate Schedule GS – Medium	Penelec Statement No. 6, P. 37, L. 1 through L.3
Rate GST – Renamed to Rate GS Large	Rate Schedule GS – Large	Penelec Statement No. 6, P. 37, L. 16 through P. 38, L.8
Rate GST Off-Peak Thermal Storage Service provision – Restrict to existing customers	Rate Schedule GS – Large	Penelec Statement No. 6, P. 37, L. 16 through P. 39, L.7
Private Outdoor Lighting Service – Restrict to existing customers and phase out	Outdoor Lighting Service	Penelec Statement No. 6, P. 39, L. 11 through P. 41, L.15

Traffic Signal Service – Eliminate schedule and serve customers under Rate GS-Small	Rate Schedule GS – Small	Penelec Statement No. 6, P. 41, L. 17 through P. 42, L.9
CTC and Generation Charges Rider – Eliminate and include in applicable rate schedules		Penelec Statement No. 6, P. 42, L. 13 through P. 43, L.4
Incubator Economic Development Rider – Eliminate		Penelec Statement No. 6, P. 42, L. 13 through P. 43, L.4
Economic Development Rider (Existing Service Locations) – Eliminate		Penelec Statement No. 6, P. 42, L. 13 through P. 43, L.4
Economic Development Rider (New Service Locations) – Eliminate		Penelec Statement No. 6, P. 42, L. 13 through P. 43, L.4
Residential Experimental Time of Use Rider – Eliminate		Penelec Statement No. 6, P. 42, L. 13 through P. 43, L.4

The ALJs recommended approval of the foregoing tariff changes.

1. Disposition

No exceptions have been filed to this determination. Finding the ALJs’ recommendation to be reasonable, appropriate and in accordance with the record evidence, it is adopted.

C. Resolved Tariff Issues

1. Rule 15d – Exit Fees

a. Positions of the Parties

MEPN proposed eliminating the year of 1996 from this rule for determining any exit fee that may be payable to the Companies if a customer either installs or extends on-site generation and reduces consumption. (MEPN St. 6 at 24-26; PN St. 6-R at 17; ME St. 6-R at 11-12). This change is needed since computer modifications have made 1996 customer billing determinants unavailable. MEPN proposed using an average of the customer’s average billing demand and energy based on

the four years immediately preceding the customer's request to invoke Rule 15d. (R.D. at 153).

MEIUG/PICA suggested two alternatives: (i) MEPN and the customer jointly develop a reasonable estimate of the customer's 1996 billing determinants and/or (ii) MEPN obtain from the customer any actual billing or other data that could be used to establish 1996 billing determinants. (MEIUG/PICA St. 1 at 50-52). The Companies agreed to modify Tariff Rule 15d consistent with MEIUG/PICA's approach, but also clarified that if no mutually acceptable data points can be established, MEPN will use the oldest billing determinants available to quantify the appropriate exit fees, taking into consideration any adjustments customers show to be relevant. (PN St. 6-R at 17; ME St. 6-R at 11-12; Tr. at 879). (R.D. at 153).

2. Limitation of Liability

The Companies proposed modifying existing Tariff Rule 26 regarding liability to comply with the Commission's statement of policy at 52 Pa. Code § 69.87 issued April 24, 1999 at Docket Nos. M-00960882 and M-00981209. (Met-Ed/Penelec St. 6 at 31-34). The revised tariff rule limits Met-Ed and Penelec's liability for actual property damage due to variations in electric supply resulting from their negligent acts and omissions. MEIUG/PICA withdrew its challenge to the modification. (Tr. at 1089; R.D. at 153-154).

3. Business Development Riders (BDRs)

The Companies placed these riders in their tariffs in 2000 as a business development tool to allow for the forgiveness of CTC for new incremental load for customers taking service under large commercial and industrial rate schedules (LP for Penelec and TP for Me-Ed). (PN St. 6 at 43-45; ME St. 6 at 47-48) No customers are

served on these riders at Met-Ed and eleven total customers are served at Penelec. Met-Ed and Penelec intended the riders to serve as an economic development tool by attracting new load into the Companies' service territories. The Companies initially proposed eliminating the riders at Met-Ed and restrict them to existing customers at existing locations at Penelec. These grandfathered riders will expire at Penelec on December 31, 2009, at the conclusion of Penelec's generation rate cap. MEIUG/PICA withdrew its opposition to the elimination of the BDRs after receiving assurances that one of its corporate clients, PPG, would still be grandfathered until December 31, 2009. (MEIUG/PICA St. 1 at 53; Tr. at 1089-1090). Met-Ed and Penelec now propose that the Commission approve Penelec's grandfathering of the BDRs until December 31, 2009, and Met-Ed's elimination of the BDRs. (R.D. at 154).

4. Rule 12b(9) Transformer Losses Adjustment

The Companies proposed modifying this rule so the 2.5% adjustment applies to kWh (energy) in addition to demand. MEPN contend that this change modifies the tariff language so that it is consistent with the way it is actually administered. (MEPN St. 6 at 22; PN St. 6-R at 16; ME St. 6-R at 11). MEIUG/PICA explained that this modification allows the Companies to adjust the energy charges on customers' bills by 2.5% to compensate for losses in the event that meters are placed at the high or low side of Company owned transformers. (ME St. 6 at 22, PN St. 6 at 22). MEIUG/PICA expressed concern regarding the revenue impact of this proposal noting an apparent increase in customer charges due to the modification. According to MEIUG/PICA, the current tariffs permit the Companies to only adjust customers' demand charges. (MEIUG/PICA St. 1 at 49).

The Companies satisfied MEIUG/PICA's concerns by explaining that this modification is not a change from the Companies' current practice, but rather, a clarification of the tariff language and that no change to revenue will occur due to the

modification. (ME St. 6-R at 10-11; PN St. 6-R at 16). As such, the Companies request approval of the modification to Tariff Rule 12b(9) as originally proposed. (R.D. at 154-155).

a. ALJs' Recommendation

The ALJs recommended that the Commission accept the above discussed tariff changes without modification. (R.D. at 152).

b. Exceptions

No parties excepted to the above resolved tariff issues.

c. Disposition

It should be noted that the Parties were able to reach a consensus on the above-discussed tariff changes. We find these unopposed tariff changes to be reasonable and in the public interest. As such, they will be adopted without modification.

D. Disputed Tariff Issues

1. Real Time Pricing (RTP) Rate

a. Positions of the Parties

PennFuture proposed that the Companies develop a RTP rate. Penn Future opined that real-time pricing encourages customers to reduce usage in high-cost, high-load periods and reduces future distribution costs. (PF St. No. 3-S at 4). According to PennFuture, peak-period energy charges, not demand charges, best reflect costs that are driven by both peak demands and energy use. (PF St. No. 3-S at 4). PennFuture stated

that transferring cost recovery off demand charges onto peak-period energy charges by real-time pricing would encourage customers to reduce usage in high-cost, high-load periods, when transmission and distribution equipment is heavily loaded. (PF St. No. 3-S at 4). PennFuture further stated that decreases in existing loads could avoid future distribution costs by freeing up existing distribution capacity and by reducing the use of existing equipment. (PF St. No. 3-S at 4-5). PennFuture advocated hedging as solution to manage the risk of price volatility for consumers. (PF St. No. 3 at 17).

PennFuture advocates that the Commission require the Companies to expand their offerings of market-responsive rates, to include smaller customers. This process would include installing appropriate improved metering for all customer groups for which the metering appears to be cost-effective and developing new rate designs. (R.D. at 156; PF St. No. 3 p. 31). In order to fund its proposal, PennFuture asserts that the Commission should order the Companies to defer the incremental costs of equipment and projects required to implement real-time pricing and to propose a mechanism for recovering the balance of program costs. (R.D. at 156; PF St. No. 3 p. 29-30).

The Companies agree that a real-time pricing rate sends the correct market signal to customers but assert that it is inappropriate to design and implement such a program at this time. (R.D. at 156; Met-Ed St. No. 6-R at 19-20). The Companies argue that any real-time pricing tariff should be voluntary, require customers to pay for metering, be implemented after the conclusion of this proceeding, and not be subject to any prevailing generation rate cap. (R.D. at 156; Met-Ed St. No. 6-R at 20). Met-Ed and Penelec believe it is premature to implement a RTP rate now before POLR customers are paying full market rates. (R.D. at 156; Penelec St. 6-R at 21; Met-Ed St. 6-R at 19-20).

The OSBA points to Duquesne Light Company's (Duquesne), implementation of real-time pricing for Large C&I customers. According to Duquesne's comments in *Policies to Mitigate Potential Electricity Price Increases*, Docket No. M

00061957, Duquesne's Large C&I customers have taken fixed price service from EGSs rather than accept hourly pricing. (OSBA M.B. at 53). The OSBA opines that real-time pricing would not alter the consumption patterns of small businesses either. *Id.* The OSBA argued that PennFuture's proposal would require the installation of expensive time-of-use meters and that PennFuture fails to set forth the cost of installing the meters. OSBA asserts that under PennFuture's proposal, customers would bear the costs of installing time of use meters. (OSBA M.B. at 54-55).

MEIUG/PICA states that the real-time pricing proposals of PennFuture are not appropriate. (MEIUG/PICA St. No. 1-R at 22-25). Specifically, MEIUG/PICA opposes a per kWh charge, arguing that since distribution costs are fixed, that cost must be allocated on a demand basis. (MEIUG/PICA St. No. 1-R at 23) MEIUG/PICA also asserts that since transmission costs are a function of peak demand, they are more properly billed on the basis of single coincident peaks. (R.D. at 157).

The Commercial Group supported PennFuture's recommendation that the Companies implement an RTP rate schedule. (CG M.B. at 25). According to the Commercial Group, the RTP rate could benefit both the utility and customers and result in peak demand reductions. (*Id.*; CG St. 1-R at 6).

b. ALJs' Recommendation

The ALJs determined that it was premature to implement a RTP rate in this proceeding. (R.D. at 158). The ALJs concluded that PennFuture failed to meet its burden of proving that a RTP would be appropriate and did not set forth the cost of implementing the rate. (R.D. at 157). The ALJs further concluded that PennFuture failed to prove that a RTP rate would shift or reduce load. *Id.* The ALJs noted the OSBA's observation that real time pricing had not altered large and commercial customers' consumption patterns in Duquesne Light Company's territory. *Id.*

c. Exceptions

According to PennFuture, the ALJs ignored substantial evidence regarding the benefits of real-time pricing. PennFuture argues that their testimony shows that real-time pricing offers various benefits to both participants and non-participants, including saving money to customers; improved reliability; reduced market prices for energy; reduced line losses; and reduced transmission and generation costs. (PF Exc. at 10). PennFuture claims that customer response to real-time pricing would tend to reduce a number of costs for all customers, including those not on real-time rates, by reducing demand for the most expensive generators, reducing the ability of generators to exercise market power, reducing peak capacity demand, and reducing upward pressure on natural gas costs. (*Id.*; PF St. No. 3 at 23-24). PennFuture notes that its RTP proposal differs from Duquesne's and states that there are flaws in Duquesne's estimate regarding customer participation as well as the absence of hedging and other price risk reduction tools in the Duquesne program. (PF Exc. at 11). PennFuture requests that the Commission consider allowing hedging and day-ahead pricing here to protect against risk. (*Id.*; PF R.B. at 5; PF St. No. 3-S at 10-11, 17-19). PennFuture excepts to the ALJs' failure to evaluate its evidence on these issues. (PF Exc. at 11).

The OSBA rejoins that PennFuture's proposal for real-time pricing would require the installation of time-of-use meters, the cost of which would be placed on the ratepayers. (OSBA R.Exc. at 18). The OSBA notes that PennFuture failed to set forth an estimate of the costs of implementing the RTP rate. *Id.* The OSBA states that the ALJs were correct in concluding that the Commission should have all pertinent facts before making a determination regarding the RTP proposal, namely, whether RTP will actually alter consumption patterns and how much the proposal would cost. *Id.*

MEPN states that the introduction of time-of-day differentials into the residential generation rates does not result in an increase in the rates charged to the rate classes in the aggregate, and is lawful and fully supported by the record. (MEPN R.Exc. at 20).

d. Disposition

It is premature to implement a RTP rate in this proceeding. In light of capped generation rates, this provision is premature and unlikely to result in substantial customer participation at this time. Moreover, this issue is more appropriately addressed in the POLR proceeding. To the extent that a large customer currently wants a RTP supply service, it can likely obtain this product from an EGS right now. As such, we will deny PennFuture's Exception on this issue.

E. Wind Product

1. Positions of the Parties

PennFuture argued that the Companies should develop a wind product like that being offered by PECO Energy and offer it to its customers at a separate rate. (PF St. 1 at 27). PennFuture recommended that the wind product should be comprised of at least 75% renewable energy, generated in Pennsylvania.

The Companies stated that they would be willing to develop a wind product subject to Commission authorization of full and timely compensation for costs incurred. (MEPN M.B. at 91).

2. ALJs' Recommendation

The ALJs concluded that PennFuture has not met its burden of proof to demonstrate that Met-Ed and Penelec should develop a wind product and offer it to their customers at a separate rate at this time. (R.D. at 158). The ALJs noted that PennFuture failed to set forth the cost of implementing the RTP rate. *Id.*

3. Exceptions

PennFuture Parties submits that the Commission should reject the Recommended Decision and require the adoption its proposed wind product. (PF Exc. at 1).

4. Disposition

We concur with the ALJs that it would be inappropriate to develop a wind product at this time absent more details. As the Companies noted, Met-Ed and Penelec have not been provided with any information on the cost of implementing such a product or how much customers would have to pay for such a product in order for Met-Ed and Penelec to fully recover those costs. As such, we will deny PennFuture's Exception on this issue.

F. Hourly Pricing

1. Positions of the Parties

Constellation argued that in order to develop a competitive market during the transition period and have it firmly established when the rate caps expire, the Companies' POLR service must introduce market-responsive pricing such as hourly priced service for the largest of C&I customers. (CNE M.B. at 24; CNE St. 1 at 9-14).

Constellation stated that the Commission should require the Companies to gradually introduce hourly priced POLR service for the largest C&I customers, those with monthly peak load contributions of 500 kW and higher, for the remainder of the transition period. *Id.* Constellation noted that 500kW is the threshold load contribution under consideration in the Commission's proposed POLR rules. Constellation explained that the 500kW threshold would ensure that the customers receiving hourly service are only those that are most sophisticated in the purchase and use of energy, and would keep the number of customers receiving hourly POLR service manageable for the Companies. *Id.*

MEIUG/PICA opposed Constellation's proposal regarding hourly pricing for large customers. MEIUG/PICA argued that the issue is outside the scope of this proceeding and should be the subject of a post rate cap POLR proceeding under Section 2807(e). (MEIUG/PICA M.B. at 82). MEIUG/PICA stated that while it is true that large customers spend a significant amount on energy, this does not mean that all large customers are able to manage the volatility inherent with hourly pricing. (*Id.*; MEIUG/PICA St. No. 1-R at 29-30). MEIUG/PICA opined that Constellation's proposal would expose the large customers, who should be receiving generation rates under the rate cap levels, to hourly pricing, regardless of whether these customers' loads and/or manufacturing processes are equipped to handle such volatility. (MEIUG/PICA M.B. at 83).

MEPN stated that it is premature to implement a RTP rate now before POLR customers are paying full market rates. (MEPN M.B. at 90; PN St. 6-R at 21; ME St. 6-R at 19-20).

2. ALJs' Recommendation

The ALJs concluded that Constellation did not meet its burden of proving that the Companies should develop hourly pricing and offer it to their large commercial

and industrial customers. (R.D. at 161). The ALJs found that Constellation failed to set forth the cost of implementing hourly pricing or whether the Companies' large commercial and industrial customers have the necessary resources to take advantage of the benefits it claims for hourly pricing. *Id.*

3. Exceptions

Constellation takes exception to the ALJs' determination that it failed to set forth whether the largest C&I customers (500 kW and above) have the necessary resources to take advantage of hourly pricing. (CNE Exc. at 11). Constellation also argues that the ALJs' arbitrary evidentiary standard is inconsistent with the Commission's *Duquesne Light POLR III* Opinion and Order which directed Duquesne Light to gradually introduce hourly priced service as the exclusive POLR product for large C&I customers of 300 kW and above. (CNE Exc. at 11). According to Constellation, the ALJs further erred in rejecting the introduction of hourly pricing until the generation rate caps expire and/or the Commission completes its POLR Rulemaking. (CNE Exc. at 13). Constellation opines that if the Commission authorizes the Companies to raise their rate caps, the gradual introduction of hourly priced POLR service to the largest C&I customers (500 kW and above) will be a legal and necessary step in fashioning a transition plan that furthers the purposes of the Choice Act and the Settlement. *Id.*

MEIUG/PICA rejoins that implementation of hourly-priced service would inappropriately subject customers to volatile pricing without adequately considering whether these customers are equipped to handle such volatility. MEIUG/PICA R.Exc. at 21). MEIUG/PICA states that the ALJs ruled correctly to reject Constellation's proposal based on the evidence of record. *Id.*

4. Disposition

With regard to hourly pricing, we agree with the ALJs that it is inappropriate to develop hourly pricing at this time. We base this conclusion on our belief that it premature to develop hourly pricing before the rate caps expire and the POLR regulations are in place. This issue would be more appropriately addressed in the generic POLR proceedings. Accordingly, Constellation's Exceptions regarding hourly pricing are denied.

G. Seasonal Time of Day Provisions (Met-Ed)

1. Positions of the Parties

MetEd proposed elimination of the Seasonal time of day (TOD) service on Schedules GS, GST, GP and TP. (ME St. 6-R at 17-18). MetEd noted that the seasonality to be eliminated is currently built into the CTC component of these rates and that regardless of their origin, CTC rates have ceased to have any connection to generation. (ME St. 6-R at 18). MetEd included seasonality in its generation rates for cost causation reasons and eliminated that feature from the other rate components on the same principle – including CTC. *Id.* According to the Companies, when looking at all rate components as an integrated package, the total rate design for Schedules GS, GST, GP and TP, including the elimination of the CTC seasonal component, is appropriate and fully justified. (MEPN M.B. at 93).

MEIUG/PICA witness, Mr. Baron, claimed that eliminating the CTC seasonality is inconsistent with MetEd's approach to seasonality in generation rate design. (MEIUG/PICA St. No. 1 at 61-62). MEIUG/PICA opposed the discontinuance of the seasonal time of day provision stating that to do so raises inter and intra-class rate design issues since it has the effect of shifting costs from one group of customers to another in violation of the Restructuring Settlement and Competition Act.

(MEIUG/PICA M.B. at 79-80). MEIUG/PICA argued that any modification to this rate design would contravene the requirements of the Competition Act, result in a modification to the generation rate cap, and would detrimentally affect ratepayers. (MEIUG/PICA M.B. at 81).

2. ALJs' Recommendation

The ALJs approved the Companies' request to eliminate the Seasonal Time of Day Service for Schedules GS, GST, GP and TP, in the CTC component of these rates. (R.D. at 162). The ALJs concluded that shifting the seasonality differential to generation rates is consistent with *Lloyd* because the cost of operating the distribution system does not depend upon when the energy is used. *Id.* The ALJs stated that seasonality appears to be a generation issue and that as set forth in *Lloyd*, each unbundled element of electric service must support itself. *Id.*

3. Exceptions

MEIUG/PICA argue that the ALJs seem to overlook the fact that allowing Met-Ed to eliminate seasonal rates, which were developed as part of the Restructuring Settlement, would violate the terms of the Competition Act. (MEIUG/PICA Exc. at 9). MEIUG/PICA opine because seasonal time-of-day rates were in place prior to the Restructuring Settlement, and specifically considered during the unbundling process, eliminating those rates prior to the expiration of the rate caps would result in improper cost shifting. (MEIUG/PICA Exc. at 9-10). MEIUG/PICA argues that it is clearly inappropriate to eliminate these rates at this time and that any such modification would detrimentally affect ratepayers. (MEIUG/PICA Exc. at 10).

The Companies rejoin that the elimination of the seasonal time-of-day service in Rate Schedules GS, GST, GP and TP does not result in an increase in the rates

charged to the rate classes in the aggregate, and are lawful and fully supported by the record. (MEPN R.Exc. at 20).

4. Disposition

We will grant MEIUG/PICA's Exception regarding the ALJs' recommendation to allow Met-Ed to discontinue its seasonal time-of-day rate. It is inappropriate to eliminate seasonal time-of-day rates schedules GS, GST, GP, and TP at this juncture. The Company has not proven on this record that all seasonality should be removed from distribution rates. Moreover, it should be noted that seasonal time-of-day rates were in place prior to the Restructuring Settlement, and specifically considered during the unbundling process. This Commission has historically given deference to maintaining rate design stability during the rate cap period to avoid improper cost shifting. As such, the ALJs' recommendation on this issue is rejected.

H. Elkland Rates

1. Positions of the Parties

Former Elkland customers (768 residential, 125 C&I, 25 lighting) have been paying rates far below Penelec's rates since 1987. (PN St. 6 at 46- 48). Penelec proposed eliminating the lower rates for these customers and integrating them into the new Penelec rates over a 90-day period after a final order is entered in this proceeding. *Id.* As an alternative, Penelec proposed a phase-in of these customers onto Penelec's rates by applying stepped discounts to Elkland customers' bills. The discounts would be 40% in 2007, 30% in 2008, 20% in 2009, and 10% in 2010. (PN St. 6-R at 9-11).

The OCA opined that Penelec's proposal to bring the Elkland rates to Penelec rate levels in one step is unreasonable and ignores the principle of gradualism. (OCA St. 5 at 28). The OCA acknowledged that the rates did need to be changed, but

noted that it was not the customers' fault that their rates have not been updated in twenty years. *Id.* In the interest of avoiding rate shock to Penelec's Elkland customers, the OCA submitted that Elkland's rates should be moved more gradually to the Penelec rate levels in at least two steps. The first step would be to implement rates from this proceeding, in a separate Elkland tariff, limited to half of the increase they would experience either under the current Penelec rates or the Penelec rates approved in this proceeding, whichever is lower. (OCA St. 5 at 28-29). In the second step, the full amount of the rate increase to Elkland customers would possibly be implemented. (OCA M.B. at 74).

2. ALJs' Recommendation

The ALJs concluded that Penelec's proposal to phase-in rates from 2007 to 2010 is the most reasonable method of bringing the rates of the former Elkland customers into line with the rates of the rest of Penelec's customers. (R.D. at 164). The ALJs stated that Penelec's proposed phase-in for the former Elkland customers via decreasing annual discounts ending in 2010 is reasonable and we will adopt it. *Id.*

The OTS accepted Penelec's proposal to phase in the Elkland rates but requested that the Company reflect the Elkland revenue at Penelec rates in the compliance filing. (OTS St. 3-SR at 19). When the Company failed to accept the OTS alternative proposal described OTS argued that the Commission should limit the increase to these customers to the increase to 60%. (OTS Exh. 3, Sched. 5). OTS witness, Mr. Kubas, stated that the increase in several of the Company's proposed Elkland rates exceed 70%. (OTS St. 3 at 29). OTS asserts any Elkland rate that is not equal to the Penelec rates should be increased to equal the Penelec rates in the next base rate case. (OTS M.B. at 56).

3. Exceptions

OTS argues that Penelec's proposal would increase some rates by more than 72 %. OTS argues that the increase in any rate should be limited to 60% and that the Elkland rates should be increased to equal the Penelec rates in the next distribution base rate case. (OTS Exc. at 6). OTS states that the Company's alternative proposal, a more gradual phase-in by providing discounts of 40 % in 2007, 30 % in 2008, 20 % in 2009 and 10 % in 2010, would be acceptable if Penelec is required to reflect the Elkland rates at the 100 % level in the compliance proof of revenue schedules. OTS opines that to allow the Company to reflect anything less than 100 % would provide a revenue windfall to the Company. *Id.* This revenue windfall would occur because the Company would receive more revenue from Elkland customers in the subsequent years than is reflected in the compliance proof of revenues schedules. *Id.*

The OCA, in its Exceptions, argues that the ALJs erred by accepting Penelec's proposal, raised in witness Pleiss's rebuttal testimony, to phase-in the proposed 76% overall rate increase to Elkland residential customers from 2007 to 2010, without further Commission review. (OCA Exc. at 15). The OCA states that in previous Commission cases approving phase-ins of rates, the utilities offered much greater detail regarding the accounting requirements and other effects that would be required or result from the phase-in. *Id.* The OCA suggests that the Commission adopt OCA witness Smith's recommendation that limits the rate increase for Elkland to no more than half of the increase that Elkland customers would receive if they paid the lower of: (1) current Penelec rates or (2) Penelec rates that result from this proceeding. (OCA Exc. at 16). Following implementation of the first step recommended by Ms. Smith, the next step can be established in Penelec's next distribution rate case. (OCA Exc. at 16; OCA R.B. at 45).

MEPN rejoins that the both the OTS' and OCA's Exceptions to the ALJs' recommendation that Penelec reflect revenue from the former Elkland customers at full rates should be denied. (MEPN R.Exc. at 20). The Companies state that neither the OTS nor the OCA provides any support for their assertion that Penelec should reflect Elkland rates at the 100% level. MEPN notes that the OTS raised this issue for the first time in its Reply Brief. (MEPN R.Exc. at 20-21). MEPN explains that it appears that OTS is concerned that if Penelec designed retail rates so that the non-Elkland customers absorbed the difference between the applicable Elkland discount and Penelec's full retail rate, this amount would continue in retail rates beyond 2010 (when the Elkland discounts are scheduled to terminate). (MEPN R.Exc. at 21). MEPN addresses this concern by stating that Penelec intends to file annual changes to its retail tariff to reduce rates for non-Elkland customers by the amount of the change in the discount applicable to Elkland customers. *Id.*

4. Disposition

We agree with the ALJs that Penelec's proposal to phase-in rates from 2007 to 2010 is the most reasonable method of bringing the rates of the former Elkland customers into line with the rates of the rest of Penelec's customers. Penelec will be required to file annual changes to its retail tariff to reduce rates for non-Elkland customers by the amount of the change in the discount applicable to Elkland customers. In this way, there is no "windfall" and no underrecovery associated with the annual Elkland changes. The OCA's and OTS' Exceptions on this issue are, therefore, denied.

XIII. SECTION 1307 RIDERS

A. Storm Damage Rider

1. Positions of the Parties

MEPN seeks approval of its Storm Damage Rider (SDR) (Rider F -- MEPN Exhs. RAD-65) in an attempt to recover storm damage O&M expenses above an amount (\$4,500,000 (ME) and \$4,400,000 (PN)), that will continue to be recovered in base rates. (MEPN M.B. at 82; ME St. 4 at 30; PN St. 4 at 31). According to MEPN, these expenses are substantial, highly volatile, and beyond the Companies' control. (MEPN Exhs. RAD-66). For ME, these expenses ranged from \$12,500,000 (2003) to \$2,400,000 (2005), while PN's costs have ranged from \$16,000,000 (2003) to \$4,600,000 (2005). *Id.*

The OTS also opposed MEPN's SDR noting that riders are traditionally used to allow utilities recovery of volatile expenses. (OTS M.B. at 26). The OTS maintained that storm damage is not sufficiently volatile to necessitate rider treatment because the Companies already recover a normalized level of storm damage expense. *Id.* OTS witness, Mr. Keim, reviewed the five year history of storm damage expenses and concluded that the budgeted claim is sufficient to account for yearly fluctuations. *Id.*

MEIUG/PICA argued that the SDR should be rejected because the Companies have not proven that the ratemaking process under which storm costs are normally collected should be circumvented. MEIUG/PICA M.B. at 66; MEIUG/PICA St. 2 at 15-16). MEIUG/PICA opined that the Companies currently have an adequate means by which to collect storm damage costs via both base rate proceedings and accounting deferrals. (MEIUG/PICA M.B. at 68). Even if the Commission determines that additional relief should be provided, this relief must come in the form of an alternative ratemaking option that would benefit both customers and the Companies, as compared to the proposed SDR, which would enable the Companies to flow-through to

customers any and all costs even tangentially related to storm damage costs without adequate Commission review. *Id.*

The OCA argued that the SDR constitutes improper single-issue ratemaking and as such should be rejected. The OCA stated that the SDR applies to costs that are part of the normal cost of providing service and do not warrant special recovery separate and apart from other costs included in base rates. (OCA M.B. at 75; OCA St. 3 at 29-32).

The OSBA opposed the Companies' SDR. The OSBA stated that the SDR would provide the Companies with an opportunity to recover selected cost increases without the need for a base rate case subject to regulatory oversight. (OSBA M.B. at 45-46). The OSBA opined that such selective recovery amounts to single-issue ratemaking. (OSBA M.B. at 46). The OSBA continued that allowing MEPN to recover selected cost increases through their riders without a base rate proceeding would be biased against the ratepayers. *Id.* The OSBA acknowledged that there can be an exception to the prohibition against single-issue ratemaking when expenses are extraordinary and nonrecurring but concluded that no such exception exists here. (OSBA M.B. at 46-47). The OSBA further noted that the SDR does not make a distinction as to what kind of storm damage costs would be recovered. (OSBA M.B. at 47).

2. ALJs' Recommendation

The ALJ's found that the arguments of OTS, OCA, OSBA, and MEIUG/PICA were persuasive and determined that the Companies did not meet their burden of proving that the SDR is in the public interest and should be approved. (R.D. at 170, 172). The ALJ's stated that the normalized level of storm damage expense recovered through base rates is sufficient to account for yearly fluctuations in storm damage expenses. *Id.* The ALJ's held that in the event of unusual storm damage, the

Companies could file a petition with the Commission for deferred accounting and seek recovery of the expense in its next base rate filing. *Id.*

3. Disposition

No party excepted to the ALJs' recommendation on this issue. We concur with the ALJs that the Companies did not meet their burden of proving that the SDR is in the public interest. As noted by the ALJs, in the event of unusual storm damage, the Companies can file a petition with the Commission for deferred accounting and seek recovery of the expense in its next base rate filing. As such, we will deny the Companies' proposed SDR.

B. Universal Service Cost Rider

1. Positions of the Parties

MEPN's proposed universal service cost riders (USCR) propose recovery of the costs of the Companies' Universal Service programs, including CARES, CAP, WARM, Fuel Fund Administration and uncollectible accounts expense. (MEPN Exh. RAD-63). MEPN wishes the USCR rate to be applied to all kWh sales delivered under the Companies' retail tariffs in order to spread the costs associated with the high levels of poverty and need in MEPN's service territories over the entire customer base. (MEPN M.B. at 83; ME PN St. 4 at 29). The initial rider amount will be 0.1730 ¢/kWh for PN (PN Exh. RAD-64) and 0.1460 ¢/kWh for ME (ME Exh. RAD-64), applied to all rate classes in each case. MEPN stated that if the USCR is not approved in this proceeding, the Companies will limit funding for the various Universal Service program costs to the amounts included in base rates. (MEPN M.B. at 83; MEPN St. 4 at 30).

According to MEPN, uncollectible accounts expense is included in the USCR: (1) to allow any change in the uncollectible expense associated with the operation

of the Universal Service programs to be accounted for timely (MEPN St. 4-R at 31-32); and (2) because these expenses are volatile. (MEPN M.B. at 83-84).

OTS witness Keim specifically rejects the inclusion of uncollectible accounts expense in the USCR as contrary to the provisions of Section 1408 of the Code, 66 Pa. C.S. § 1408. (OTS St. 2 at 12-13). OTS recommended that CARES, Fuel Fund Administration, Gatekeeper, WARM, and uncollectible accounts expense not be included in the USCR. (OTS M.B. at 20). OTS allowed CAP expense in the USCR, but rejected the proposed recovery and recommended that such expenses not be reconciled. *Id.* OTS explained that the CARES, Fuel Fund Administration, Gatekeeper, and WARM expenses should be removed from the USCR because they are not subject to volatility; therefore, it is proper to continue to recover these expenses through base rates rather than through the USCR. (OTS M.B. at 20-21).

The OSBA argued that universal service programs are an “insurance policy” for which the “insured customers” should pay the “premiums.” (OSBA M.B. at 34). According to the OSBA, MEPN’s universal service costs should be recovered solely from non-CAP residential customers. (OSBA M.B. at 35). The OSBA opposed the inclusion of uncollectible account expenses in the USCR arguing that: (1) the volatility of the Companies’ uncollectible account expenses can be mitigated by the Companies’ determination to increase collection efforts; (2) uncollectible account expenses are within the Companies’ control since the Companies have many tools at their disposal to collect bills from those customers who fail to pay; and, (3) if MEPN were allowed to recover their uncollectible account expenses through an automatic surcharge mechanism, there would no longer be an incentive for the Companies to make vigorous efforts to collect unpaid bills. (OSBA M.B. at 37). OSBA’s witness Mr. Kalcic testified universal service costs should be allocated either on the basis of cost-causation or on the basis of benefits received. Under both of these approaches, residential customers should be assigned

100% of the cost responsibility for universal service programs. (OSBA R.B. at 17; OSBA St.1-ME at 6; OSBA St. 1-PE at 5).

The OCA argued that the USCR should be rejected because such costs should be collected in base rates. (OCA M.B. at 76). The OCA opined that the USCR constitutes improper single-issue ratemaking, reduces the incentive to properly manage costs, and covers a normal cost of providing service that does not require special treatment. (OCA M.B. at 77; OCA St. 6 at 4-6). The OCA stated that if the USCR were approved, uncollectible expenses should not be included. However, the OCA argued that if the USCR were approved, it should be recovered from all customer classes because all derive some benefit from the programs. (OCA M.B. at 78-79). According to the OCA, “[t]his approach would be consistent with the general statutory framework for allocating universal service costs articulated in Sections 2802(17) and 2804(9) of the Public Utility Code. 66 Pa. C.S. §§ 2802(17), 2804(9) (universal service program costs “shall be funded in each electric distribution territory by non-bypassable, competitively neutral cost-recovery mechanisms that fully recover the costs of universal service and energy conservation service”).” (OCA M.B. at 79).

MEIUG/PICA argued that, under a cost causation theory, because the residential customer class is responsible for 100% of the costs of these programs, this same class should be assigned 100% of the cost responsibility. (MEIUG/PICA M.B. at 55; MEIUG/PICA St. 1 at 43-44). MEIUG/PICA stated that the Companies’ proposal to allocate USP costs on a per kWh volumetric basis to all customer classes additionally and unreasonably impacts industrial customers. (MEIUG/PICA M.B. at 60). MEIUG/PICA also oppose the inclusion of uncollectible expenses in the USCR. (MEIUG/PICA M.B. at 61-63).

2. ALJs' Recommendation

The ALJs found that the Companies' proposal to recover universal service costs through an annually reconciled rider that imposes a per kWh surcharge, meets the statutory requirement that universal service costs be fully recoverable by the utility. (R.D. at 175). The ALJs, therefore, recommended the removal of all the revenues and expenses that are associated with universal service costs from base rates, \$6,791,000 revenues in Met-Ed's base rates and \$7,292,000 revenues in Penelec's base rate. *Id.* The ALJs determined that the agreed upon amounts of \$19,072,000 for Met-Ed and \$23,132,000 for Penelec for universal service programs shall be entirely collected and expended through the USCR. (R.D. at 175-176). The ALJs rejected MEPN's and the OCA's proposal that the USCR be applied to all customer classes and instead limited it to the residential class. (R.D. at 177-179). The ALJs recommended the addition of a separate line item on the residential customers' bills indicating the amount billed for the universal service costs. (R.D. at 179).

3. Exceptions

The OCA submits that the ALJs erred in recommending approval of the USCR and argues that Rider E should be excluded from the Companies' tariffs and the Companies should continue to collect their universal service costs through base rates. (OCA Exc. at 17). The OCA argues that the USCR is inappropriate because it rests on the premise that a surcharge is needed to fully recover universal service costs. This necessarily assumes that the relationship between costs and revenues has changed merely because certain expenses increase, but totally ignores that other expenses may decrease or that revenues may increase over the same time period. *Id.* According to the OCA, the USCR is inconsistent with traditional ratemaking principles that prohibit single-issue ratemaking. (OCA Exc. at 18). The OCA also states that the ALJ's recommendation should be rejected because rider costs are supposed to be those costs that are beyond a

utility's control and those that are difficult to predict. (OCA Exc. at 19). The OCA opines that the universal service costs are neither beyond the Companies' control nor difficult to predict and are therefore not those costs that are appropriately to be recovered through a rider. *Id.* The OCA contends that the ALJ's recommendation should be rejected because of the inherent inefficiencies associated with the use of riders outside of base rates; as an automatically adjusting mechanism, the incentive for efficiency and cost management is greatly diminished. (OCA Exc. at 19-20).

The OCA also takes exception to the ALJ's recommendation that universal service costs should be recovered only from the residential class. (OCA Exc. at 20-27). The OCA states that it has provided substantial record evidence that demonstrates that all customer classes benefit from universal service programs. According to the OCA, benefits include: (1) providing a wage supplement to allow low-income workers to meet their basic needs; (2) decreasing turnover, absenteeism and tardiness; and (3) improving the competitiveness of local businesses. (OCA Exc. at 23).

The OCA further takes exception to the ALJ's recommendation that universal service costs be stated as a separate line item on customers' bills. The OCA argues that this is bad policy and not supported by the record evidence. (OCA Exc. at 27-28).

MEPN rejoins that the recovery of particular costs via a Section 1307 mechanism is a recognized exception to the prohibition on single issue ratemaking. (MEPN R.Exc. at 22). MEPN argues that because universal service costs satisfy the criteria for recovery via a rider mechanism, there is no violation of single issue ratemaking. *Id.* MEPN continues that any consideration of traditional ratemaking principles must yield to express statutory mandates that require full recovery of such costs. *Id.* MEPN cites to the changing needs of customers and the growing levels of poverty in their service territories. (MEPN R.Exc. at 22-23). The Companies note that

the Commission has many ways to address the alleged lack of incentive to manage these costs under such a rider, including the: (1) the broad audit and review of the costs and application of the rider mechanism under the terms of the USCR and Section 1307 of the Code; (2) the Commission's Bureau of Consumer Services which oversight of these programs. (MEPN R.Exc. at 23).

Both the OSBA and MEIUG/PICA state that the ALJs properly determined that the Companies request for recovery of universal service program costs should be allocated only to the residential class. (OSBA R.Exc. at 13-16; MEIUG/PICA R.Exc. at 15-17).

4. Disposition

We concur with the ALJs who correctly approved the use of the USCR to recover universal service costs. Further, the ALJs correctly limited recovery of the USCR to residential customers. These recommendations are consistent with the Commission's Order on *Customer Assistance Programs: Funding Levels and Cost Recovery Mechanisms*, Docket No. M-00051923 (December 18, 2006). We disagree with the ALJs' recommendation regarding the USCR bill line item. The USCR is just one of the Companies' many operating expenses. No compelling justification has been presented for separately identifying this particular operating expense on residential customer bills. As such, we reject the ALJs' recommendation to itemize the USCR.

C. Government Mandated Programs Rider

1. Positions of the Parties

MEPN proposed a government mandated programs rider (GMPR) (Rider J - MEPN Exhs. RAD-67) as a mechanism to recover all of the costs of any program required by legislative action or by a governmental agency. MEPN provided that the

GMPR would remove the uncertainty of recovery for costs over which the Companies have no control, as to amount, timing or the reasons for their incurrence. (MEPN St. No. 4 at 32-33). According to MEPN, some of the possible costs mentioned in this proceeding that could be recovered via the GMPR include the \$30 million for renewable energy programs, \$5 million in consumer education spending, \$30.6 million for DSM/energy efficiency expenditures as proposed by PennFuture witnesses, and new funding for MEPN's Sustainable Energy Funds. (MEPN M.B. at 84-85).

The Companies disputed the Parties' claims regarding single issue ratemaking. According to MEPN, the recovery of a particular set of costs, such as those proposed by the GMPR, via an automatic rate adjustment mechanism under Section 1307 is a recognized exception to any prohibition on single issue ratemaking. (MEPN M.B. at 85). MEPN stated that there are protections built into the rider structure, including annual filings and the Commission's right to audit and review the rider and its charges annually. (*Id.*; ME St. 4-R at 44; PN St. 4-R at 43-44).

The OCA opposed the GMPR, stating that the costs are the very type of costs that should be reviewed and evaluated for reasonableness, prudence and eligibility for recovery from ratepayers in a base rate case. (OCA M.B. at 75). The OCA raised the same objections it raised to the SDR noting that: (1) the GMPR covers costs that are already a part of the overall cost of service therefore potentially resulting in a double recovery of costs that are not incremental costs already recognized in setting rates; and (2) the rider reduces the incentive to properly manage and control costs because cost recovery is guaranteed. (*Id.*; OCA St. 3 at 29-32).

MEIUG/PICA objected to the GMPR stating that the Companies have not demonstrated that the costs are identifiable, material, volatile, or that they cannot otherwise be addressed through the base ratemaking process. (MEIUG/PICA St. 2 at 9).

OTS argued that not only does the GMPR violate the well established prohibition against single issue ratemaking, the request for an initial rate of \$0.00 demonstrates that there is no legitimate need for recovery outside the context of traditional ratemaking procedures. (OTS M.B. at 24-25).

The OSBA opposed the GMPR. The OSBA concurred with MEIUG/PICA's expert, Mr. Kollen, on the following:

The costs recoverable through the [Government Mandated Program] Riders are not limited in any manner. Any costs the Companies' management determines somehow may qualify as Government Mandated Programs Costs will be eligible for recovery through the proposed tariffs. Taken to an extreme, any costs incurred by the Companies arguably would qualify for recovery through [Government Mandated Program] Riders given the utilities' ultimate obligation to serve, which itself is a government mandate. As evidence of this extreme possibility that any/or all costs may be qualified for recovery through the [Government Mandated Program] Riders, the definition of the eligible Government Mandated Programs includes 'all activities, functions, and/or programs provided by the Company to or for benefit of Customers.' The proposed [Government Mandated Program] Riders are open-ended and subject to significant discretion and abuse.

(OSBA M.B. at 51; MEIUG/PICA St. 2 at 13).

2. ALJs' Recommendation

The ALJs agreed with the objecting Parties that the GMPR is an attempt by the Companies to circumvent the ratemaking process and that it should be denied. (R.D. at 184). The ALJs found that the Companies failed to meet their burden of proving that the GMPR is necessary. The ALJs further found that because the costs to be included in the GMPR were not specifically identifiable, the need for the rider is highly speculative. *Id.*

3. Exceptions

No exceptions were filed on this issue.

4. Disposition

We concur with the ALJs that the Companies failed to meet their burden of proving that the GMPR is necessary. The fact that the costs to be included in the GMPR were not specifically identifiable supports the speculative nature of the proposed rider. The ALJs recommendation to reject the GMPR is therefore, adopted.

XIV. DIRECTED QUESTIONS OF VICE CHAIRMAN CAWLEY

By Secretarial Letter dated July 14, 2006, all Parties in this proceeding and the presiding ALJs were provided a copy of Vice Chairman Cawley's directed questions to be addressed in this case. The directed questions and the ALJs' summary of the responses are contained in Appendix A attached to this Opinion and Order. In their discussion of the directed questions, the ALJs noted that only seven Parties responded: the Companies; MEIUG/PICA; PennFuture; OCA; and, the Commercial Group. (R.D. at 185). OTS filed its Exception No. 3 and stated that the ALJs had overlooked the OTS' responses. We will grant this Exception and include the OTS' responses in Appendix A.

XV. MISCELLANEOUS

In its Exception No. 4, OSBA notes that the ALJs directed the Companies to file tariffs designed to produce revenues not in excess of the total revenue requirements found to be appropriate in this proceeding. OSBA argues that the Companies should be directed to file tariffs which specify the revised rates for each separate service (i.e.,

generation, stranded costs, transmission and distribution) for which a change in rates has been approved. OSBA further argues that the Companies should be directed to show the detailed calculations of the adjustments approved by the Commission for each service, the rates the Companies will charge for each service and the proof of revenue for each service. OSBA asserts that this is consistent with Section 2804(3) of the Code, 66 Pa. C.S. § 2804(3), relating to unbundling, and *Lloyd*.

We will grant this Exception and provide the recommended direction.

OSBA also filed its Exception No. 5 and reiterated its request that the Companies be required to include in their compliance filings redlined copies of their compliance tariffs to assist the Parties and the Commission in their review and analysis of the compliance filing. We agree with this suggestion and will provide the necessary direction.

Constellation filed its Exception No. 5 and claims error in the ALJs' failure to recommend the initiation of a working group to develop a competitive wholesale solicitation process for the procurement of POLR supply beginning in 2011. (Constellation Exc. at 15-17). The Companies responded and noted that the Commission has already convened a working group to address request for proposal documents and supplier master agreements for POLR supply at Commission Docket No. M-00061960. The Companies observed that the first meeting of the working group was held on July 26, 2006, and representatives for Constellation attended. The Companies assert that there is no need for a working group focused on the Companies in light of the working group that has already been convened. (Companies R.Exc. at 23). We agree with the Companies and deny this Exception.

Constellation filed Exception No. 6 and argues that the ALJs erred when they failed to direct that the Companies provide programs for customer education

regarding competitive markets, pricing and supply acquisition tools. (Constellation Exc. at 18-19). We will deny this Exception. Issues involving customer education will be addressed on a generic basis in the Commission's proceeding on *Policies to Mitigate Potential Electricity Price Increases* at Commission Docket No. M-00061957.

Constellation also filed its Exception No.7 and argues that the ALJs erred by failing to ensure that administrative costs for POLR service must be included in the Companies' POLR rates. Constellation asserts that it is not clear that the Companies COSS properly separated out POLR administrative costs from other services. Constellation argues that unless those costs are split out and allocated wholly to POLR service, shopping customers will be paying for services they no longer receive from the Companies. Constellation concludes that the Companies should be required to perform a fully unbundled COSS that accounts for POLR administrative costs. (Constellation Exc. at 19-20).

The Companies respond that Constellation has failed to show that those costs are eliminated for shopping customers since they can return to POLR service at any time. Accordingly, there is no need to break those costs out in a separate fashion and no justification for exempting shopping customers from paying those costs. (Companies R.Exc. at 24). OSBA responds that Constellation's argument ignores the fact that the Companies' generation rates are capped through 2010. In addition, Constellation has failed to produce any evidence to determine whether those costs are already included in the Companies' POLR rates. Accordingly, OSBA argues that Constellation has failed to meet its burden of proof on this issue. (OSBA R.Exc. at 17).

We will deny this Exception. We agree with the OSBA that Constellation ignores the fact that the Companies are currently under rate caps. We also agree that Constellation failed to produce any evidence on the issue of whether POLR

administrative costs are already included within the POLR rates or are embedded in some other service.

XVI. CONCLUSION

For the reasons discussed above, we will adopt the Recommended Decision of Administrative Law Judges Wayne L. Weisman and David A. Salapa as modified by, and consistent with the foregoing Opinion and Order; **THEREFORE,**

IT IS ORDERED:

1. That the Exceptions of Parties are granted or denied, consistent with this Opinion and Order.

2. That Metropolitan Edison Company shall not place into effect the rules, rates and regulations contained in Tariff - Electric Pa. P.U.C. No. 49, the same having been found to be unjust, unreasonable and, therefore, unlawful.

3. That Pennsylvania Electric Company shall not place into effect the rules, rates and regulations contained in Tariff - Electric Pa. P.U.C. No. 78, the same having been found to be unjust, unreasonable and, therefore, unlawful.

4. That Metropolitan Edison Company's Petition for Approval of a Rate Transition Plan, Docket No. P-00062213, is denied.

5. That Pennsylvania Electric Company's Petition for Approval of a Rate Transition Plan, Docket No. P-00062214, is denied.

6. That Metropolitan Edison Company is hereby authorized to file tariffs, tariff supplements, or tariff revisions containing rates, provisions, rules and

regulations, consistent with the findings herein, to produce revenues not in excess of \$1,210,883,000. The compliance filings shall separately state the total amount of revenues for generation, transmission, distribution, universal services, and stranded costs.

7. That Pennsylvania Electric Company is hereby authorized to file tariffs, tariff supplements, or tariff revisions containing rates, provisions, rules and regulations, consistent with the findings herein, to produce revenues not in excess of \$1,147,801,000. The compliance filings shall separately state the total amount of revenues for generation, transmission, distribution, universal services, and stranded costs.

8. That Metropolitan Edison Company's tariffs, tariff supplements, or tariff revisions described in Ordering Paragraph No. 6, above, may be filed upon less than statutory notice, pursuant to the provisions of 52 Pa. Code §§ 53.31, *et seq.*, and 53.101, and may be filed to be effective for service rendered on and after the date of entry of this Opinion and Order.

9. That Pennsylvania Electric Company's tariffs, tariff supplements, or tariff revisions described in Ordering Paragraph No. 7, above, may be filed upon less than statutory notice, pursuant to the provisions of 52 Pa. Code §§ 53.31, *et seq.*, and 53.101, and may be filed to be effective for service rendered on and after the date of entry of this Opinion and Order.

10. That Metropolitan Edison Company shall file detailed calculations with its compliance filings, which shall demonstrate to this Commission's satisfaction that the filed tariffs and adjustments comply with the provisions of this Opinion and Order. The filing shall include a redlined version of the tariff indicating where changes have been made.

11. That Pennsylvania Electric Company shall file detailed calculations with its compliance filings, which shall demonstrate to this Commission's satisfaction that the filed tariffs and adjustments comply with the provisions of this Opinion and Order. The filing shall include a redlined version of the tariff indicating where changes have been made.

12. That Metropolitan Edison Company shall comply with all directives, conclusions and recommendations contained in the body of this Opinion and Order, which are not the subject of any individual directive in these ordering paragraphs, as fully as if they were the subject of a specific ordering paragraph.

13. That Pennsylvania Electric Company shall comply with all directives, conclusions and recommendations contained in the body of this Opinion and Order, which are not the subject of any individual directive in these ordering paragraphs, as fully as if they were the subject of a specific ordering paragraph.

14. That Metropolitan Edison Company and Pennsylvania Electric Company shall retain 100% of the merger savings amount and are not required to allocate any portion of the merger savings to their ratepayers.

15. That Metropolitan Edison Company and Pennsylvania Electric Company shall increase transmission rates, including congestion and other related costs, via a Transmission Service Charge Rider, with such costs to be recovered through both energy and demand allocators in an automatic adjustment mechanism consistent with the provisions of Section 1307 of the Public Utility Code, 66 Pa. C.S. § 1307.

16. That Metropolitan Edison Company and Pennsylvania Electric Company shall be permitted to recover their deferred test year transmission costs as set forth in their filing and herein. The deferred 2006 transmission costs shall be bypassable.

17. That Metropolitan Edison Company's and Pennsylvania Electric Company's requests to increase the average retail Competitive Transition Charge rate is denied.

18. That Metropolitan Edison Company's and Pennsylvania Electric Company's requests to accrue carrying charges on deferred NUG stranded cost balances is denied.

19. That Metropolitan Edison Company's and Pennsylvania Electric Company's requests to recover any amount by which the NUG locational marginal pricing and capacity cost (NLACC) exceeds their respective Provider Of Last Resort (POLR) revenues is denied.

20. That except as otherwise provided herein, Metropolitan Edison Company's and Pennsylvania Electric Company's proposed rate changes for schedules RS, RT, GS, GST, GP and LP are approved consistent with this Opinion and Order.

21. That Metropolitan Edison Company's proposal to eliminate the Seasonal Time of Day Services on GS, GST, GP and TP is denied consistent with this Opinion and Order.

22. That Metropolitan Edison Company's and Pennsylvania Electric Company's proposed tariff changes for Rule 15d-Exit Fees, Rule 26-Limitation of Liability, the Business Development Rider and Rule 12b(9)-Transformer Losses Adjustment, having been resolved by the Parties are approved consistent with this Opinion and Order.

23. That Metropolitan Edison Company and Pennsylvania Electric Company shall not include a Real Time Pricing Rate in their respective tariffs, the same having been found to be unjust, unreasonable and not in the public interest.

24. The Metropolitan Edison Company and Pennsylvania Electric Company shall not include a Wind Product Rate in their respective tariffs, the same having been found to be unjust, unreasonable and not in the public interest.

25. That Metropolitan Edison Company and Pennsylvania Electric Company shall not include an Hourly Pricing Rate for their customers of 599 kW and above in their respective tariffs, the same having been found to be unjust, unreasonable and not in the public interest.

26. That Metropolitan Edison Company shall not modify its Tariff rate GST by modification of the time-of-day provisions so as to change the on-peak period from 8 hours to 12 hours.

27. That Metropolitan Edison Company shall be allowed to eliminate Rider G (Sustainable Energy Fund Rider) from its Tariff.

28. That Pennsylvania Electric Company shall be allowed to eliminate Rider I (Sustainable Energy Fund Rider) from its Tariff.

29. That Metropolitan Edison Company and Pennsylvania Electric Company shall not include a Storm Damage Rider in their respective tariffs, the same having been found to be unjust, unreasonable and not in the public interest.

30. That Metropolitan Edison Company and Pennsylvania Electric Company shall include a Universal Service Cost Rider in their respective tariffs, in

accordance with the provisions of Section 1307 of the Public Utility Code, 66 Pa. C.S. § 1307, designed to produce revenues in the amount of \$11,978,000 for Metropolitan Edison Company and in the amount of \$16,299,000 for Pennsylvania Electric Company. The Universal Service Cost Rider shall apply only to Metropolitan Edison Company's and Pennsylvania Electric Company's residential customer class.

31. That Metropolitan Edison Company and Pennsylvania Electric Company shall not set forth the monthly amount billed to residential customers under the Universal Service Cost Rider as a separate line item on the bill.

32. That Metropolitan Edison Company and Pennsylvania Electric Company shall not include a Government Mandated Programs Rider in their respective tariffs, the same having been found to be unjust, unreasonable and not in the public interest.

33. That the Complaints of Met-Ed Industrial User Group and Industrial Energy Consumers of Pennsylvania, the Office of Small Business Advocate, the Office of Consumer Advocate, R.H. Sheppard Co., Inc., Penelec Industrial Customer Alliance and Industrial Energy Consumers of Pennsylvania, Pierre Fortis, and L.C. Rhodes are, to the extent they have not been previously marked closed, sustained in part and dismissed in part, consistent with this Opinion and Order.

34. That the Pennsylvania Public Utility Commission's inquiry and investigation in Docket No. R-00061366 is terminated and the record closed.

35. That the Pennsylvania Public Utility Commission's inquiry and investigation in Docket No. R-00061367 is terminated and the record closed.

36. That the record at Docket No. P-00062213 be marked closed.

37. That the record at Docket No. P-00062214 be marked closed.

38. That the record at Docket Nos. A-110300F0095 and
A-110400F0040 be marked closed.

BY THE COMMISSION,

James J. McNulty
Secretary

(SEAL)

ORDER ADOPTED: January 11, 2007

ORDER ENTERED:

Tables

Appendix A

DIRECTED QUESTIONS OF VICE CHAIRMAN JAMES H. CAWLEY

The following discussion is the ALJs' summary of the Vice Chairman's Directed Questions and the responses thereto found at Pages 185 – 201 of the Recommended Decision. The discussion has been corrected to include OTS' responses.

By Commission Secretarial Letter dated July 14, 2006, all parties and the presiding ALJs were provided a copy of Vice Chairman Cawley's directed questions to be addressed in this consolidated case. The Vice Chairman's questions were:

1. Do fixed charges for residential and small or medium commercial customer distribution services discourage conservation of energy? If so, what other revenue decoupling models can be implemented that would optimally meet the dual needs of providing incentives for consumers to conserve energy, while providing reasonably stable distribution revenues for utilities?
2. Do demand-based charges remove the incentive for consumers, especially small to medium sized C&I customers, to conserve energy? If so, should demand-based rates for such customers also be phased out over time?
3. Can and should rate designs vary among customer classes? For example, larger industrial and commercial ("C&I") customers generally have a much smaller percentage of their revenues attributable to distribution services. Given this dynamic, does the commodity design of supply service rates provide adequate incentive for larger C&I customers to conserve energy?

Of the eighteen parties to the consolidated case, eight chose to address the Vice Chairman's questions. The Companies, OCA²⁵, MEIUG and PICA and IECPA, PennFuture, and the Commercial Group addressed the Vice Chairman's questions both in written testimony and in their respective Main Brief. OSBA and Constellation addressed the Vice Chairman's questions only in their respective written testimony.

The Companies addressed the Vice Chairman's questions in their Main Brief at page 99, and in their written testimony at Met-Ed/Penelec Statement 3-R, at 54-61 and at Met-Ed Statement 6-R, pp.25-30 and Penelec Statement 6-R, pp.25-30.

OCA addressed the Vice Chairman's questions in its Main Brief at pages 96-97, and in its written testimony at OCA Statement 5R, at 6-8 and OCA Statement 6R, at 11-15.

MEIUG and PICA and IECPA addressed the Vice Chairman's questions in its Main Brief at Appendix E, and in its written testimony at MEIUG and PICA and IECPA Statement 1-S at 28-31.

PennFuture addressed the Vice Chairman's questions in its Main Brief at pages 25-26, and in its written testimony at PennFuture Statement 3-S, at 12-16.

The Commercial Group addressed the Vice Chairman's questions in its Main Brief at page 25, and in its written testimony at Commercial Group Statement 1-S, at 6-9.

OSBA addressed the Vice Chairman's questions in its written testimony at OSBA Statement 2-ME/PE, at 14-16.

²⁵ OCA did not address Question #2 of the Vice Chairman's directed questions.

Constellation addressed the Vice Chairman's questions in its written testimony at Constellation Statement CNE 1-S, at 9-12.

The Companies addressed the Vice Chairman's questions in the following manner. The Vice-Chairman's questions focused on the interplay between fixed and demand charges in rate design and conservation incentives. The fundamental rate design principle is that pricing should be based on costs. Using distribution rates as an incentive to promote conservation of generation resources, if successful, is likely to result in the unintended consequence of the utility failing to be able to recover its allowed revenue. Other pricing arrangements are more effective in attaining conservation objectives, the primary one being setting rates at levels commensurate with current costs, and not under pricing the resource intended to be the target of conservation. Cost-based fixed charges and demand charges in distribution rate design are appropriate to recover fixed costs and should not be misused to attain objectives not associated with distribution cost recovery.

With respect to the Vice Chairman's first question, the Companies do not believe that cost-based fixed charges associated with distribution services discourage conservation. From a rate design perspective, fixed customer charges are utilized to recover the Companies' fixed costs associated with serving the customer. These include the fixed costs associated with such things as meters, meter reading, billing and collection, etc. As currently implemented, fixed customer charges usually represent a relatively small percentage of a customer's total bill for distribution service. However, the Companies' investment in and the size of their distribution system are not dependent upon and are largely unrelated to customer's energy usage. Ideally, more of the Companies' costs would be recovered via the demand component in distribution rates. However, recovery of these costs via demand charges is constrained by, among other things, lack of demand meters at residential customer premises and restrictions on what residential customers can pay. Any reduction or elimination of the existing or proposed

customer charge or fixed fee would not measurably encourage customer conservation because these fixed charges represent such a small portion of a customer's typical bill.

With respect to the Vice Chairman's second question, the Companies do not believe that cost-based demand charges remove the incentive for medium sized C&I customers to conserve energy. The Company stated that they really need to think of energy conservation in two terms: (i) demand side management, the reduction in peak usage during peak periods, which presumably limits the need to add capacity and (ii) energy conservation, the overall reduction of energy (kWh) consumption. From a rate design perspective, it makes sense to use demand-based rates to collect fixed costs associated with serving the customer, as in the case of distribution. Since the costs associated with supplying the necessary infrastructure to serve the customer do not vary significantly based on the amount of energy (kWh) consumed, collecting distribution charges on a demand basis provides a modest level of revenue stability to the Companies, and gives customers appropriate incentives to implement demand side management programs. So long as the demand rates are seeking to recover largely fixed costs that are not dependent upon and do not vary based on consumption, such charges can properly co-exist with usage charges and customers will still have the appropriate incentives to conserve energy. For commodity components of the rates (i.e., generation), it makes sense to pass the energy-related pricing signals through to customers. Recovering all generation costs through energy rates is completely consistent with the principle of cost causation which is the underlying basis for all sound rate design. Adherence to cost causation will provide proper price signals to customers and encourage energy conservation by having energy charges more reflective of the underlying commodity based product. Increasing energy charges while decreasing demand charges (or vice versa) provides customers with competing and often contradictory approaches for either employing demand side management or conserving energy. The Companies continue to believe that demand charges are a reasonable and valuable component of pricing.

With respect to the Vice Chairman's third question, the Companies believe that rate design can and should vary among customer classes. The Companies plan to continue to implement time of day, demand based and seasonal pricing based upon customers' unique characteristics in order to send them appropriate price signals. Sound rate design, both for large and small customers, needs to be guided in principle by cost causation. In the case of the Companies' delivery systems, the costs should be allocated to customer classes based on their level of use of the system (i.e., Cost of Service Study). Rates to recover commodity based costs (i.e., generation charges), should reflect the market in which the Companies obtain the supply. However, unless and until the Companies' existing generation rate caps are eliminated, customers are not likely to conserve significantly since their retail price for generation is disconnected from the underlying wholesale cost of such generation.

OCA addressed the Vice Chairman's questions in the following manner. OCA noted that if fixed charges are set higher at a given overall revenue level, and if these increases are accompanied by lower energy charges, consumers will have less incentive to conserve.

With respect to the Vice Chairman's first question regarding revenue decoupling models, OCA noted four significant concerns:

- 1) Unless revenue decoupling is based on a complicated methodology that considers weather, it will insulate utility revenues from variations due to weather as well as other factors. This would be a significant reduction of risk to the utility, and should be accompanied by a reduction in the return on equity or change in capital structure.

- 2) Revenue decoupling will tend to increase the complexity of regulation, particularly in unbundled states.

3) Revenue decoupling is not an end in itself. If tried, it should be part of a comprehensive conservation and energy efficiency program.

4) Revenue decoupling will result in rates increasing because of reduced consumption. This is a very mixed and confusing signal to customers, as it may at first appear that the less you use the more you pay. Any revenue decoupling thus requires significant consumer education.

In general, to the extent that customers have discretionary usage, high customer charges discourage conservation and are frustrating to consumers. It is important to recognize, though, that simply increasing usage charges will not necessarily have the effect of incenting conservation efforts by many low income customers. Low-income energy consumption can be divided into two different categories: (a) discretionary consumption; and (b) nondiscretionary consumption. Nondiscretionary consumption is by far the biggest block of the two. Energy usage in low-income households, however, is generally driven by factors largely outside of the ability of the household to control. The age and efficiency of the dwelling unit, the size of the dwelling unit, the number of household members, and the extent to which household members are home during the day are all factors that are beyond the household's ability to control. Moreover, the condition of the physical structure, including not only the structural integrity of the unit but factors such as the location of an apartment within a multifamily structure, the condition of the HVAC system in any particular home, and the orientation of a home or apartment *vis a vis* direct sunlight, are all factors beyond a household's ability to control. The largest use of electricity in the average U.S. household is for appliances (including refrigerators and lights), which consume approximately two thirds of all the electricity used in the residential sector. Refrigerators consume the most electricity (14 percent of total electricity use for all purposes), followed by lighting (9 percent). Low-income households are significantly conserving

already in these two areas, however. While low-income households have less efficient usage for lighting and electric appliances due to older and less efficient equipment, the primary driving force behind total consumption of electric appliance and lighting is the number of square feet in the home.

Pennsylvania needs to be very careful about the impact on low-income customers from raising rates as a mechanism to create incentives for pursuing energy conservative behavior. A careful balancing is needed. Moving substantial cost recovery into fixed charges would eliminate the incentive that does exist for low-income customers to pursue those measures that are both technically and economically available, and that can affect their discretionary use. In addition, moving substantial cost recovery into fixed charges would disproportionately place the recovery of a utility's cost of service on low-use customers. These low-use customers tend, also, to be low-income customers. Due to the large non-discretionary usage of low-income households, and the substantial barriers that impede conservation investments by these households, going too far in the other direction also would not be appropriate.

With respect to the Vice Chairman's third question, OCA noted that rate designs do vary among customer classes. However, larger customers may in a better position than smaller customers to shape their load and alter their energy usage, and it would therefore be more economical for larger customers to install sophisticated meters.

MEIUG and PICA and IECPA addressed the Vice Chairman's questions in the following manner. The first principle of rate design should be that, to the extent feasible, rates should reflect cost of service. This means that residential rates should generally include a customer charge and a kWh charge. In the case of POLR supply service, the cost of power includes both an energy cost component and a capacity charge in the form of a kW demand charge. It would be contrary to economic pricing principles to ignore the underlying wholesale pricing structure in the development of POLR supply

rates. To ensure that such principles are addressed, demand charges should be reflected in POLR default service pricing. Rate designs should vary by customer class. There are substantial cost differences that must be recognized in the design of rates for individual customer classes.

With respect to the Vice Chairman's first question, MEIUG and PICA and IECPA state that the first principle of rate design should be that, to the extent feasible, rates should reflect cost of service. This means that residential rates should generally include a customer charge and a kWh charge. If residential customers are demand metered, it is also appropriate, based on generally accepted and reasonable cost of service methodologies, to incorporate a kW demand charge in the rate design, reflecting the maximum 15 minute demand during the month or during the on-peak period (if time differentiated pricing is implemented). If rates are set based on cost of service, customers will receive proper and efficient price signals that will guide their consumption. Such rates do not either discourage or encourage conservation, but rather, encourage efficient and economic use of energy. While it is true that, all else being equal, higher kWh rates will result in lower consumption (and thus "conservation"), it does not follow that this is an optimal outcome. If off-peak energy, for example, is lower cost than on-peak energy, efficiency is not promoted by raising the off-peak rate simply to discourage usage. If rates are based on cost, including cost based fixed charges where justified, customers will face prices that are consistent with the costs of providing each component of electric service, and these customers will make rational consumption decisions.

With respect to the Vice Chairman's second question, MEIUG and PICA and IECPA believe that it is appropriate to design rates based on cost of service. In the case of POLR supply service, the cost of power includes both an energy cost component and a capacity charge in the form of a kW demand charge. It would be contrary to economic pricing principles to ignore the underlying wholesale pricing structure in the development of POLR supply rates. This means that demand charges should be reflected

in POLR default service pricing. In particular, where the utility continues to collect stranded costs from customers via a CTC charge, the combined CTC and generation rate should reflect both demand and energy charges.

With respect to the Vice Chairman's third question, MEIUG and PICA and IECPA state that rate designs should vary by customer class. There are substantial cost differences that must be recognized in the design of rates for individual customer classes. Customers on large power rates typically have much higher load factors than residential and small commercial customers. They also take service at primary and transmission voltages, which means that it costs less to obtain the POLR supply for these customers. It would be both economically inefficient and inequitable to ignore these cost differences among customer classes in the design of rates. Though, ideally, each rate should be comprised of customer, demand, and energy charges, residential and small commercial customers do not usually have demand meters and therefore, it is not feasible to include a demand charge for these rates. For larger customers with demand meters, it is appropriate to include a demand charge in the rate design, reflecting the underlying cost structure of the service.

PennFuture addressed the Vice Chairman's questions in the following manner. Fixed charges for distribution services discourage conservation of energy, compared to recovering the same revenue through energy charges; fixed charges are not appropriate vehicles for recovering most distribution costs, since many distribution costs vary with load limits and energy use. Demand charges for distribution service discourage conservation of energy, compared to recovering the same revenue through energy charges. Large commercial and industrial distribution rates should reflect the contribution of load to sizing of equipment and aging of distribution equipment, with most of the costs recovered through energy and coincident-peak charges, rather than fixed customer charges or demand charges driven by the customer's own peak.

With respect to the Vice Chairman's first question, PennFuture believes that fixed charges for distribution services discourage conservation of energy, compared to recovering the same revenue through energy charges. The greater the portion of the bill recovered through fixed charges, the lower the energy charges, the less the customer saves from energy conservation, the lower the incentive to conserve. The effect on the level of energy charges is most pronounced for residential and small or medium commercial customers, where fixed charges tend to be the largest percentage of total distribution revenues. Fixed charges are not appropriate vehicles for recovering most distribution costs, since many distribution costs vary with load levels and energy use. Distribution costs are driven by a combination of the following factors:

- the coincident peak load on each piece of equipment;
- high short-term loads, even if they are below peak, because they contribute to the heating that reduces the load-carrying capacity of the equipment in the peak hour and keeps the equipment from cooling off overnight;
- energy use, especially in the hours and days immediately preceding high peaks. Summer energy use in particular tends to shorten the life of distribution equipment by overheating and degrading the insulation.

If the Commission wishes to decouple revenues from sales levels, the most direct way to do so would be to set up a decoupling mechanism (also frequently called a revenue adjustment mechanism (RAM)). Typically, a RAM would consist of the following components, all set by the Commission:

- A base distribution revenue target for each company (or perhaps each class).
- Rules describing how that target would change with various indices, potentially including customer

number, inflation, and some measure of economic activity. The objective would be to approximate the revenues that the company would normally expect to receive. In the short run sales tend to increase with customer number, usage trends and the local economy. In the longer term, inflation tends to increase utilities' costs, leading these companies to file rate cases. If the Commission intends that the decoupling delay rate-case filings, perhaps as part of performance-based ratemaking, inflation may be a significant consideration. If the Commission is content with more-frequent rate filings, inflation should probably not be reflected in the adjustments to the target. Decoupling will automatically provide a form of weather normalization; if the Commission wants to avoid that outcome, it can adjust the revenue target for actual weather.

- The conditions under which the decoupling plan would be terminated, which might include a severe economic downturn, or dramatic changes in energy use per customer.
- The rules for the computation of the RAM balance, including the time period of each computation (e.g., monthly, quarterly), whether the RAM will be computed by class or in total, and whether interest will accrue on the balance. The importance of interest will depend in large part on how long the balance is allowed to accrue.

The Commission could determine in advance how the RAM balance would be rolled into rates (through a periodic rate adjustment or through deferral to the next rate case), or it can leave that issue to be determined once the magnitude of the balance and other factors are known. For example, if power costs are high, and the RAM balance is positive (i.e., ratepayers owe the shareholders), the Commission might prefer to defer an adjustment. If the RAM balance is negative, the Commission may choose to flow it through in a time of high power costs, to moderate total bills. Or if power costs drop, that might be a good time to flow through a positive balance. Proper design of a RAM is not

simple. The Commission might decide in this docket to initiate a proceeding to develop a decoupling mechanism for the Companies; attempting to develop the mechanism within a rate case is probably ill-advised.

With respect to the Vice Chairman's second question, PennFuture states that demand charges greatly reduce the incentive to conserve, and should be phased out. Like customer charges, demand charges for distribution services discourage conservation of energy, compared to recovering the same revenue through energy charges. Demand charges are determined by the customer's individual maximum demand, not contribution to high cost peak hours. Therefore, demand charges are not very effective at reflecting costs or at encouraging customers to shift loads off high-cost hours. Those costs that are driven by peak demands and energy are best reflected in peak period or super-peak energy charges, not demand charges. In addition, demand charges in time-of-use rates should be reduced, and the cost recovery should be transferred to peak-period energy charges. This approach will encourage customers to reduce usage in high-cost, high-load periods, when transmission and distribution equipment is heavily loaded. For customers without time-of-use meters, distribution costs should continue to be recovered through energy charges rather than being transferred to demand or customer charges.

With respect to the Vice Chairman's third question, PennFuture believes that properly designed, real-time market prices charged to large C&I customers by the Companies or competitive suppliers will give large customers an incentive to conserve equal to the cost of market supply. The supply service charges do not include the incremental costs on the distribution system due to increased load. Hence, large C&I distribution rates should also be structured to reflect the contribution of load to the sizing and aging of distribution equipment, with most of the costs recovered through energy and coincident-peak charges, rather than fixed customer charges or demand charges driven by the customer's own peak. Some distribution equipment close to the large customer, and typically sized to accommodate the customer's load, might be charged on a non-

coincident billing demand. The fact that distribution charges are a smaller share of the bill for the large C&I customers than for smaller customers means that appropriate distribution rate design is less important for the larger customers, but there is no reason not to structure all rates as efficiently as practical.

The Commercial Group addressed the Vice Chairman's questions in the following manner. The importance of sending a price signal to conserve energy is generally a positive objective but must be balanced with the importance of setting rates based on cost and minimizing cross-subsidies. Revenue decoupling mechanisms should be avoided. Such mechanisms add complexity to the ratemaking process, transfer revenue risk from utilities to customers, and are a form of single-issue ratemaking that can result in rate increases determined solely by usage reductions, without regard to other factors, some of which could, if properly considered, move rates in the opposite direction from the single-issue change. While it is important to retain equitable relationships across rate classes, rate designs should vary among customer classes. This is generally a function of the differing costs to serve various customer classes, as well as the metering technology required to send an improved price signal.

In commercial customer classes, setting fixed charges below fixed costs and recovering the shortfall from the energy charge has the undesirable result of causing larger and higher-load-factor customers to pick up the fixed-cost responsibilities of smaller and lower-load-factor customers. This is particularly problematic given that the relative differences in electricity usage among commercial (and industrial customers) are driven largely by the differing requirements of their respective businesses, as opposed to individual consumption preferences. Further, in the specific case of designing *distribution* charges for commercial customers, such a policy would create a separate subsidy problem associated with substituting energy charges for demand charges. So also, assuming charges are properly aligned with costs at the outset, shifting cost recovery responsibility from demand charges to energy charges will simply result in a

cross-subsidization within the rate schedule, as higher-load factor customers are forced to pick up the fixed costs of lower-load-factor customers.

With respect to the Vice Chairman's first question, the Commercial Group states that the question implies that in the absence of fixed charges, energy charges would be higher. However, this is not always the case, as distribution rates for commercial and industrial customers are often structured without an energy component. This is appropriate, as distribution costs are strictly customer-related and demand-related. The fixed charge component of a customer's bill should correspond to the fixed, customer-related costs as much as practicable, and the demand-related costs should be recovered through a demand charge, when the use of demand metering is cost-effective. If the cost of demand metering is not justifiable, such as in the case of most residential customers, an energy charge can be substituted as a second-best alternative. All things equal, lower energy charges will result in a weaker incentive to conserve. To the extent that fixed charges are viewed as resulting in lower energy prices, then a somewhat weaker incentive may result. However, given that fixed charges are typically not a significant portion of overall revenues, it is not clear that the weaker price signal is at all material. Further, regulated utilities typically offer a range of DSM programs to counteract the price signal effect. The importance of sending a price signal to conserve energy must also be balanced with the importance of setting rates based on cost and minimizing cross-subsidies.

In commercial customer classes, setting fixed charges below fixed costs and recovering the shortfall from the energy charge has the undesirable result of causing larger and higher-load-factor customers to pick up the fixed-cost responsibilities of smaller and lower-load-factor customers. This is particularly problematic given that the relative differences in electricity usage among commercial (and industrial customers) are driven largely by the differing requirements of their respective businesses as opposed to individual consumption preferences.

A grocery store might be pursuing vigorous energy efficiency measures, but still be consuming twenty times the electric power of a gas station, due to the nature of the business. It would not be reasonable to artificially reduce the fixed charge paid by the gas station below the fixed cost to serve it, and transfer the revenue shortfall to the energy rate paid by the grocery store in order to send a stronger conservation price signal to the grocer. Further, in the specific case of designing *distribution* charges for commercial customers, such a policy would create a separate subsidy problem associated with substituting energy charges for demand charges. Revenue decoupling mechanisms should be avoided. Such mechanisms add complexity into the ratemaking process, transfer revenue risk from utilities to customers, and are a form of single-issue ratemaking that can result in rate increases determined solely by usage reductions, without regard to other factors, some of which could, if properly considered, move rates in the opposite direction from the single-issue change.

With respect to the Vice Chairman's second question, the Commercial Group believes that demand-based charges are intended to recover demand-related costs and should not be artificially reduced so that energy charges can be increased to encourage conservation. First of all, demand charges send their own price signal regarding the impact on the system of demand-related usage. Second, assuming charges are properly aligned with costs at the outset, shifting cost recovery responsibility from demand charges to energy charges will simply result in a cross-subsidization within the rate schedule, as higher-load factor customers are forced to pick up the fixed costs of lower-load-factor customers. The irony here is that high-load-factor commercial and industrial customers already pay significantly higher total energy bills than their low-load-factor counterparts with equal demand. As a result, they are often keenly aware of the impact of energy costs to their business, and are among the most aggressive in pursuing energy conservation opportunities. Shifting added costs to these customers in order to send a stronger price signal is not in the public interest.

With respect to the Vice Chairman's third question, the Commercial Group states that while it is important to retain equitable relationships across rate classes, rate designs should vary among customer classes. This is generally a function of the differing costs to serve various customer classes, as well as the metering technology required to send an improved price signal. For example, the added cost of advanced meters can be justified by the improved price signal that is sent by TOU rates for larger C&I customers. This can provide an incentive for C&I customers to be especially aware of energy conservation opportunities during on-peak hours when energy is more expensive.

OSBA addressed the Vice Chairman's questions in the following manner. In theory, any fixed charge will diminish a conservation price signal simply because the charge is unavoidable. However, whether or not the hypothetical conversion of a fixed distribution charge into a variable or usage-based charge would lead to more conservation is unclear. While demand charges are not completely unavoidable, *energy* conservation measures may leave a customer's monthly demand relatively unaffected. All else being equal, one would expect that larger C&I customers would be least affected by distribution-related conservation price signals.

With respect to the Vice Chairman's first question, OSBA states that in theory, any fixed charge will diminish a conservation price signal simply because the charge is unavoidable. However, whether or not the hypothetical conversion of a fixed distribution charge into a variable or usage-based charge would lead to more conservation is unclear. While the resulting price signal would be stronger, the *incremental* increase in that price signal may or may not be significant. Also, the actual weight given to distribution charges will vary by rate class, and by customer within each rate class. However, for most customers, the decision to conserve is more likely to be driven by potential savings in generation costs than by distribution costs, due to the much greater (relative) weight given to generation charges on a customer's monthly bill.

Consider the case where a utility's fixed distribution charges were to be abandoned in favor of usage-based charges, *and* usage per customer were to decline due to a conservation response. In such circumstances, the utility would experience revenue erosion. A revenue decoupling mechanism is intended to sever the link between a utility's kWh sales and revenues, and provide some measure of revenue stability. Generally, with a revenue decoupling mechanism in place, a utility would be allowed to track and to recover lost usage-related revenues from ratepayers in a subsequent period(s). In practice, however, the mechanism does more than keep the utility "whole." By severing the link between sales and revenues, a revenue decoupling mechanism drastically reduces a utility's underlying business risk. For example, a utility's sales (and earnings) would no longer be impacted by weather or economic conditions. Therefore, if the Commission were to adopt a revenue decoupling mechanism, it should also implement a commensurate reduction in the utility's allowed return on equity.

With respect to the Vice Chairman's second question, OSBA states that to some extent, a demand-based distribution charge is similar to the fixed charge. While demand charges are not completely unavoidable, *energy* conservation measures may leave a customer's monthly demand relatively unaffected. If so, the incentive to conserve energy would be theoretically diminished, compared to the case where demand charges were eliminated in favor of energy charges. Such charges are a remnant of the pre-restructuring era, and are generally inconsistent with today's market prices for generation service.

With respect to the Vice Chairman's third question, OSBA states that it is unaware of any electric utility that recovers its distribution revenue requirement solely from kWh-based charges within each of its rate schedules. OSBA agrees that, all else being equal, one would expect that larger C&I customers would be least affected by

distribution-related conservation price signals, given the much smaller weight given to distribution charges on such customers' bills.

Constellation addressed the Vice Chairman's questions in the following manner. Fixed distribution charges for residential and small or medium commercial customers may or may not influence a customer's decision to voluntarily conserve energy. Demand charges may have the effect of encouraging energy conservation. Rate design principles should lead to distribution and energy (and other) charges perhaps being a different proportion of the total bill.

With respect to the Vice Chairman's first question, Constellation believes that fixed distribution charges for residential and small or medium commercial customers may or may not influence a customer's decision to voluntarily conserve energy. A larger piece of a customer's bill is the energy charge and because the energy charge is the larger piece of the bill, it will likely be the driver for customer energy conservation. In essence, the amount of the total bill and the accuracy of the price signals contained in the bill are the elements that will drive customers to conserve energy.

With respect to the Vice Chairman's second question, Constellation states that demand charges may have the effect of encouraging energy conservation. Large industrial customers are typically aware that one way to reduce their monthly energy bills is to control their peak demand. Many of the larger customers use energy conservation programs to "clip their peaks" to provide these savings. However, the large industrial customers may be more educated about their energy consumption patterns than small to medium sized customers. The industrial customers most likely have hourly integrated meters and energy systems that in real time give them valuable information concerning their energy usage. In addition, the large industrial customers may utilize on-site generation or reduction of particular high energy consumption processes to reduce their demand charges. The small to medium size customers cannot be aware of their real time

energy usage and prices if they only have a monthly meter. Further, smaller customers may not have processes that could be curtailed to provide a major savings on their energy bill. Demand based rates need not necessarily be phased out if customers are provided real time usage. Requiring the installation of hourly integrated meters, with the ability to measure demand, would most likely lead to energy conservation.

With respect to the Vice Chairman's third question, Constellation believes that different customer classes may respond to different price signals for energy and distribution depending on their ability to modify their energy consumption. Rate design principles should lead to distribution and energy (and other) charges perhaps being a different proportion of the total bill. Sending the proper price signals to customers is important in promoting energy conservation. It is the size of the total bill and the ability to receive accurate price signals that drives changes to customer consumption resulting in energy conservation. The most critical element is delivering the price signal to the customer.

OTS responded to the Vice Chairman's directed questions. As summarized at Page 7 of the OTS Exceptions, they stated the following:

- Q. Do fixed charges for residential and small commercial customer distribution services discourage conservation of energy? If so, what other revenue decoupling models can be implemented that would optimally meet the dual needs of providing incentives for consumers to conserve energy, while providing reasonably stable revenues for utilities?
- A. OTS believes that the average customer is more concerned with the total bill, and not necessarily with the components of their bill. Therefore increasing the total bill will likely cause the average customer to conserve. The key is customer education and the recovery of fixed charges. OTS St. 3-SR, at 23-24.

- Q. Do demand charges remove the incentive for customers, especially small to medium size Commercial and Industrial customers to conserve energy? If so, should demand based rates be phased out?
- A. As described above, a higher total bill will promote customer conservation. This phenomenon is true whether such increase is the result of higher demand or energy charges. OTS believes a lower demand charge does not necessarily result in lower energy use as a customer might simply switch energy usage from the peak to the off-peak period. OTS St 3-SR, at 24-25.
- Q. Can and should rate designs vary among customer classes. For example, larger Industrial and Commercial (“C&I”) customers generally have a much smaller percentage of their revenues attributable to distribution services. Given this dynamic, does the commodity design of supply service rates provide adequate incentive for larger C&I customers to conserve energy?
- A. OTS believes that there should be different rate designs among customer classes since each class of customer puts different demands on the system. OTS St. 3-SR at 25.

EXHIBIT B

Pennsylvania Public Utility Commission

May 03, 1988

R-870732

Reporter

1988 Pa. PUC LEXIS 407 * | 67 Pa. PUC 91 | 93 P.U.R.4th 189

Pennsylvania Public Utility Commission v. Pennsylvania Power Company

Core Terms

recommend, plant, defer, rate base, customer, load, block, dividend, valve, phase-in, energy, calculate, ratepayer, electric, annual, depreciate, estimate, charcoal, premium, growth rate, ratemaking, modify, fuel, barometer, carrying charges, nuclear, outage, tariff, peak, amortize

Counsel

James R. Edgerly, Esquire, Stephen L. Field, Esquire, 1 East Washington Street, P.O. Box 891, New Castle, PA 16102-0891, For Respondent

Alan L. Reed, Esquire, Thomas P. Gadsden, Esquire, Jack E. Jerrett, Morgan, Lewis & Bockius, 2000 One Logan Street, Philadelphia, PA 19103, For Respondent

Alan P. Buchmann, A. E. Korkosz, H. J. Nicols, Squire, Sanders & Dempsey, 1800 Huntingdon Bldg., Cleveland, OH 44115, For Respondent

Dennis P. Harkwaik, 520 Madison Avenue, New York, NY 10022, For Respondent

Scott J. Rubin, Joan C. Fitzpatrick, Marlane Chestnut, Christine Maloni, 1420 Strawberry Square, Harrisburg, PA 17120, For Office of Consumer Advocate

Wayne T. Scott, Carol F. Pennington, P.O. Box 3265, Harrisburg, PA 17120, For Office of Trial Staff

Michael P. Kerrigan, Esquire, 214 State Street, Harrisburg, PA 17101, For Hospital Council of Western PA

Charles R. Cornelius, Esquire, P.O. Box 270, Farrell, PA 16121, For Sharon Steel Corporation

Thomas J. Fee, House of Representatives, P.O. Box 81 - Main Capital Bldg., Harrisburg, PA 17120

Hon. [*2] Michael C. Gruitza, House of Representatives, House Pose Office - Main Capitol, Harrisburg, PA 17120

Panel: Commissioners Present: Bill Shane, Chairman, dissenting in part; William H. Smith, Vice-Chairman; Linda C. Taliaferro; Frank Fischl

Opinion

OPINION AND ORDER

BY THE COMMISSION:

I. INTRODUCTION AND HISTORY OF THE PROCEEDING

On August 5, 1987, Pennsylvania Power Company (hereinafter "Penn Power" or "Respondent"), filed Supplement No. 69 to its Tariff Electric-Pa. P.U.C. No. 33 to become effective October 4, 1987. Supplement No. 69 contains proposed changes in rates, rules and regulations calculated to produce approximately \$86.3 million in additional revenues based upon the future level of operations in the twelve months ending April 30, 1988. The proposed increase would result in an average increase of 46.6% in Pennsylvania jurisdictional base rate revenues.

Penn Power's primary purpose in seeking this sizable increase in rates is to recover the capital and operating costs associated with its investment in Perry I. Penn Power estimates that its share of Perry I costs, represents a 68% increase in the existing rate base and \$28.0 million in additional annual operating expenses.

By Order adopted at Public Meeting on September 17, 1987, we instituted a formal investigation to determine the lawfulness, justness [*3] and reasonableness of the proposed rates, rules and regulations. Supplement No. 69 was, therefore, suspended by operation of law for the seven-month period, pursuant to Section 1308(d) of the Public Utility Code (66 Pa. C.S. § 1308(d)), or until May 4, 1988. The matter was assigned to Administrative Law Judge ("ALJ") Michael A. Nemeck for hearing and the issuance of a Recommended Decision.

Among the parties participating in this proceeding were Penn Power and the Office of Consumer Advocate ("OCA"). Additionally, pursuant to the provisions of 66 Pa. C.S. § 306(b), the Commission's Office of Trial Staff ("OTS") also participated in the proceeding. The Hospital Council of Western Pennsylvania filed a petition to intervene which was granted by prehearing Order dated October 8, 1988. The instant proceeding was consolidated with the pending Duquesne Light Company proceeding docketed at R-870651 for the limited purpose of developing a common record on issues relating to the construction of Perry I.

A prehearing conference was held on October 7, 1987. Seventeen evidentiary hearings were held in Harrisburg and Pittsburgh between October 13, 1987, and December 17, 1987, before ALJ [*4] NemeC. Consonant with the Commission's policy, a public input session was held in Penn Power's service territory at New Castle, Pennsylvania on November 17, 1987. The record as developed in this case consists of a transcript in excess of 1500 pages exclusive of the matters pertaining to the construction of Perry Unit No. 1.

The evidentiary record was closed on December 17, 1987. Briefs and Reply Briefs were filed by Penn Power, the OTS and the OCA. On March 11, 1988, the Recommended Decision of ALJ NemeC was issued wherein it was recommended that Penn Power file rates designed to produce total annual revenues not in excess of \$248,796,100, an increase of \$72,629,729. Exceptions and Reply Exceptions were filed by Penn Power, the OTS and the OCA on March 23, 1988 and March 30, 1988, respectively.

II. THE COMPANY

In his Recommended Decision the ALJ provided the following information regarding the Company.

Penn Power is a regulated Pennsylvania public utility and is a wholly owned subsidiary of Ohio Edison Company (Ohio Edison). 1 This history of the Company, which includes the purchase, consolidation, and merger of 139 formerly independent operating companies, is set forth [*5] in PP Ex. I, Section B-1. Penn Power's principal executive offices are located at New Castle, Pennsylvania.

On April 30, 1988, the Company will render electric service to approximately 130,386 retail customers (PP Ex. I Future, p. C1). Its service territory, which has a total population of 350,000, encompasses an area of 1,517 square miles in western Pennsylvania, including all of Lawrence and Mercer counties and portions of Allegheny, Beaver Butler, and Crawford counties (PP Ex. I, Sections B-1 and B-2). The Company additionally provides wholesale electric service to five municipal customers under rates prescribed by the Federal Energy Regulatory Commission (FERC).

The Company's largest source of baseload generation is its own New Castle plant, which consists of five separate coal-fired units. In addition, as a member of the Central Area Power Coordinating Group (CAPCO), 2 the Company shares in the ownership of Bruce Mansfield Units Nos. 1, 2, and 3 and Sammis Unit No. 7, all coal burning [*6] facilities, and of Beaver Valley Nuclear Unit No. 1 and Perry Nuclear Unit No. 1. Finally, together with Ohio Edison, Penn Power owns a share of four smaller peaking units (diesel or combustion turbine) (PP Ex. I, Section B-2). Penn Power also owns a share of Perry 2, but makes no claim in this case based on that share.

The principal facilities of the Company, including transmission lines and substations, as well as the extent of the Company's service territory, are shown on the system map included in PP Ex. I, Section B-3. Penn Power presently employs approximately 1,752 men and women to meet the needs of its customers (PP Ex. I, Section B-2).

III. PUBLIC INPUT HEARING

The ALJ provided the following report regarding the significant matters which arose at the Public Input hearing held in New Castle, Pennsylvania, on November 17, 1987.

The public input hearing [*7] for the current case was held on November 17, 1987, in New Castle. Approximately one hundred persons turned out on a wet, dreary evening to attend the session. Of those who attended, fifteen presented statements.

The overwhelming majority of comments addressed the adverse financial impact of any increase on persons of low income. For example, Ms. Salley Seifert, Information and Referral Coordinator for Active Aging, Inc., Crawford County, presented a moving statement detailing the difficulties encountered by a client, "Elizabeth", in living at age 76 of a fixed income of \$395.00. Of that amount she spends \$60 to \$65 on utility service. She has gone without new shoes for five years, and needs new eyeglass lenses, which she cannot afford. Ms. Seifert asked that this Commission consider all of the "Elizabets" in Penn Power's service territory when it establishes rates in the present case. Tr. of 11/17/87, pp. 13-16.

Other speakers addressed confusion and concern over public street lighting rates for the City of New Castle. For example see the statement of Mr. Michael T. Yagersky at transcript pages 37 through 40. Specifically, the concern is that Penn Power is basing its [*8] billing on lumens, a measurement of luminosity. At my request the matter was investigated and reported on both by the Company and OCA. The Company presentation was made in PP St. 1-R, pp. 13-16, by Mr. Joseph Pazak, which was attached to the OCA letter to the customers dated December 10, 1987.

Q. At the Commission's public input hearing in New Castle several questions were raised concerning the use of the term "lumens" in the street lighting schedules. What is your understanding of the problem?

A. Those who testified at the public input session expressed the dissatisfaction and confusion regarding the inclusion of "lumens" in the Company's street light schedules. These concerns probably arise from a decision several years ago by the New Castle City Council to begin to replace existing street lights with high pressure sodium vapor lamps. The intent of that decision was simply to provide more light at less or the same cost. During the course of converting to sodium vapor lamps, Penn Power was granted general rate increases of approximately 20% in January 1982 (R-811510) and approximately 6.5%, in September 1982 (R-821918). When the City's bill for street lighting increased, [*9] it apparently was blamed on the inclusion of lumens in the rates.

As explained above, lumens have always been part of the Company's street light rates but the charges have always been determined on the basis of energy (kwh) consumption. However, some city residents apparently believed that lumens were a new aspect of the rate schedule and somehow contributed to the increased cost. The matter has been explained, and hopefully, is now understood by the City administration.

PP St. 1-R, pp. 15-16.

The December 10, 1987, letter from OCA recounts that an informal survey disclosed that most major electric utilities base street lighting rates on the type and size of the lamp as usage is not metered. The charge for electricity is based on an estimate of the amount of electricity used by a lamp over its anticipated useful life. The lumen designation is used to identify the type of lamp; the rate for service is based on the estimated electrical usage.

The matter as explained is comprehensible and not objectionable. It is suggested that if any citizens still are troubled by the matter that they contact the responsible public official and review the contract terms between the municipality [*10] and Penn Power. They should then contact Penn Power and informally discuss the matter in detail. If such a request is made, Penn Power is urged to provide that employee most knowledgeable to answer questions. The affected municipality, of course, as the customer, has the ongoing right to avail itself of the formal complaint procedures provided by this Commission.

Finally, several persons expressed concerns over the safety and high cost of nuclear power plants in general and, with particular emphasis on cost, to Penn Power's involvement in Perry Unit 1. For example see the statement of Ms. Sophie Ellis at transcript pages 25 through 37.

The appropriate response to the legitimate concerns expressed at the public input hearing is to conduct a thorough review of the claims presented by Penn Power in the present proceeding. The following sections deal both with the prudence of Penn Power's participation in Perry 1 and the effect of Perry 1 on Penn Power's overall generation capacity. Also reviewed are all contested claims for increased expenses and allowable return, as well as issues related to how any allowed increase will be collected and whether any phase-in of such an increase [*11] should be ordered.

R.D., pp. 5-8.

IV. RATE BASE

A. Prudence of Perry Unit No. 1 Construction

1. Prior History 1

The Perry 1 nuclear generating unit was built and is operated by Cleveland Electric Illuminating Company, (CEI), a subsidiary of Centerior Energy Corporation. 13.74% of it is owned by Duquesne Light Co., with Pennsylvania Power Co. owning 5.24%, and the remainder held by CEI, Toledo Edison Company (subsidiaries of Centerior) and the holding company which owns Penn Power, the Ohio Edison Company.

In the recently concluded Duquesne Light Co. rate case at Docket No. R-870651, the OCA had moved to consolidate the construction prudence issues relating to Perry 1 with the rate case in this proceeding. On September 11, 1987, the Chief Administrative Law Judge granted the motion. Therefore, all testimony, exhibits, and cross-examination on the Perry 1 issues were presented in conjunction with the proceedings in the Duquesne case at Docket No. R-870651.

The discussion herein will in effect mirror the resolution of the construction prudence issues for Perry 1 as [*12] detailed in Docket No. R-870651.

This Commission last addressed the construction issues regarding the prudence of the cost of Perry 1 in the immediately preceding Duquesne and Penn Power rate cases. The Order in the Penn Power case is reported as Pennsylvania Public Utility Commission v. Pennsylvania Power Company, 85 PUR 4th 323 (1987). This prior proceeding was litigated at the \$4.9 billion cost level. This Commission determined that no adjustment for alleged imprudence should be made, based on the record in that proceeding. This determination left open the question of the prudence of costs between the \$4.9 billion expended as of March 21, 1986, and the approximately \$5.4 billion shown in the present case, for costs up to November 18, 1987, the date Perry Unit No. 1 entered commercial service.

2. Standards for Determining Construction Prudence

The legal standards for a prudence inquiry are set forth in Sections 515 and 1308(f) of the Public Utility Code. Section 515(a) provides, in pertinent part:

No later than 30 days after construction of an electric generating unit is begun, either in this Commonwealth or in some other state, any public utility operating in this Commonwealth [*13] and owning any share in that unit shall submit to the Commission an estimate of the cost of constructing that unit.

Section § 1308(f) of the Public Utility Code provides:

Whenever there is filed with the Commission any tariff stating a new rate based in whole or in part on the cost of constructing an electric generating unit, the Commission shall compare the estimated construction cost filed in accordance with Section 515(a) (relating to construction cost of electric generating units) with the actual construction cost submitted by the utility in support of that tariff. If the actual construction cost exceeds the estimated construction cost, the rate determined by the Commission under this section shall not be based on any part of that excess unless the public utility proves that part of the excess to have been necessary and proper. In making its determination under this subsection, the Commission shall consider all relevant and material evidence, including evidence obtained pursuant to Section 515. For purposes of this subsection "construction" includes any work performed on an electric generating unit when required, or is expected to require, the affected public utility to [*14] incur an aggregate of at least \$100,000,000 of expenses which, in accordance with generally accepted accounting principles, are capital expenses and not operating and maintenance expenses. (Emphasis added)

In Re: Salem Nuclear Generating Station, 70 PUR 4th 568, 574 (1985) the Commission approved the following interpretation of construction prudence:

Prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made. In determining whether a judgment was prudently made, only those facts available at the time judgment was exercised can be considered. Hindsight review is impermissible.

Imprudence cannot be sustained by substituting one's judgment for that of another. The prudence standard recognizes that reasonable persons can have honest differences of opinion without one or the other necessarily being imprudent.

Cost disallowance based on imprudence is not permitted unless the alleged imprudence was the real and proximate cause of some injury. Thus, for example, if the alleged imprudent conduct did not cause any extension of outage time, such conduct [*15] could not be the basis for denying a utility's recovery of replacement power costs. (Emphasis in original).

Because it is the utility and not its ratepayers which selects the persons who work on a construction project, the utility may not pass through charges to ratepayers in order to recover costs unnecessarily incurred due to the inadequate performance of its agents, contractors, or subcontractors.

The Public Utility Code explicitly places the burden of proof of demonstrating the reasonableness of rates, justifying accounting entries and verifying future test year estimates on the involved utility. Therefore, in this proceeding, Penn Power has the burden of demonstrating the reasonableness of the claimed expenditures constituting the difference between the \$4.9 billion expended at the time of the prior case and the \$5.4 billion cost as of November 18, 1987.

3. Power Ascension Program

It took the Perry nuclear plant more than twenty (20) months to go from initial fuel load to commercial operation at a cost of about \$540 million. This initial start-up or shakedown period is referred to in the nuclear power industry as the power ascension program. The OCA argues that several [*16] general areas of Company imprudence during this period significantly contributed to this twenty month delay and the roughly half billion dollars in additional costs. These areas are denominated as charcoal fires, reactor core isolation cooling ("RCIC") system problems, main stream isolation valve problems, various alleged human errors and procedural problems and a miscellaneous category. They will be discussed seriatim.

Other events outside the Company's control certainly had an effect on the Perry 1 schedule. The State of Ohio prevailed initially before the United States Circuit Court of Appeals for the Sixth Circuit to obtain a stay of the issuance of a full power license for Perry. On September 4, 1986, the Sixth Circuit prevented the NRC from voting on the issuance of a full power license. The stay was lifted to permit the NRC to grant the license which was, in turn, stayed. Full power operation was finally approved on December 23, 1986.

(a) Charcoal Adsorber Combustion

The series of events which comprise what has come to be called the charcoal combustion events commenced on June 18, 1986, when CEI employed radiant heaters to raise the ambient air temperature in the [*17] area containing a system designed to cool and cleanse waste gases. The events as summarized in the subsequent NRC report were as follows:

On June 20, 1986, at 1145 hours, an Unusual Event was declared by the licensee based on their determination that the activated charcoal in at least two of the off-gas charcoal adsorber vessels was burning. The fire was apparently initiated by radiant energy type space heaters placed in close proximity to the charcoal adsorber bed vessels. Prior to the ignition of the charcoal, the space heaters were being utilized to elevate system temperatures in preparation for a test which required that the vault and equipment have an initial temperature of at least 150 degrees F for

testing of the temperature pulldown capability of the Off-Gas Vault Refrigeration System. After identification of the fire, a nitrogen gas purge of the Off-Gas System was initiated to control the fire at 1219 hours on June 20, 1986 to monitor and evaluate progress of the licensee's effort to extinguish the fire.

On June 23, 1986 a Confirmatory Action Letter (CAL) was issued by Region III in which the licensee committed to preserve information, equipment, and specific documentation [*18] regarding this fire. The licensee also committed to develop a recovery plan.

On June 23, 1986, at 1151, the Unusual Event was terminated. The nitrogen purge activities continued until adsorber bed vessel entry on June 27, 1986. After charcoal sampling activities were established and maintained on both A and B trains of the adsorber beds.

On July 6, 1986 the nitrogen purge of the off-gas system was stopped. Subsequently, a dry instrument air purge at 60 scfm was initiated through trains A and B. Approximately one hour after the initiation of this instrument air purge, the center thermocouples on adsorber beds 14A and 148 indicated temperatures greater than 250 degrees F. On July 6, 1986 at 2037 an Unusual Event was declared based on the determination that the adsorber bed charcoal had re-ignited. A nitrogen purge was initiated through the beds. The second Unusual Event was terminated on July 8, 1986 after it was determined that an acceptable rate of decrease in adsorber bed temperature and negligible concentrations of combustion products were present in the nitrogen purge stream. During July 15 thru 17, 1986 the existing adsorber bed charcoal was removed from vessels. [*19]

OCA Ex. 7A, Attachment 5, NRC Report No. 50-440/860020, pp. 2-3.

The purpose of the test that started on June 18, 1986, was to test the effectiveness of the Perry Off-Gas System which is designed to ". . . process and control the release of gaseous radioactive effluents to the site environs . . ." in as safe a manner as possible. The system was described, in part, as follows:

The Perry Off-Gas System (a non-safety augmented quality system) is made up of three segments. The first segment consists of preheaters, catalytic recombiners, an off-gas condenser, and a water separator. These components are used to recombine the hydrogen and oxygen, and to remove moisture from the off-gas process stream. The second segment consists of a hold-up line which allows any short-lived activity in the off-gas process stream to decay. The third segment consists of cooler condensers, moisture separators, prefilters, desiccant-type gas dryers, gas coolers, charcoal adsorber trains, and after filters which remove trace moisture, allow adsorption of iodine, and delay the passage of Krypton and Xenon.

The charcoal adsorber trains are comprised of eight charcoal adsorber vessels (each 25 ft. [*20] high by 4 ft. in diameter) . . . Each adsorber vessel contains approximately three tons of activated coconut shell charcoal. The adsorbers are located in the Off-Gas System charcoal vaults in the Off-Gas Building. The first adsorber in each train is located in a separate vault. The remaining three adsorber vessels in each train are located in another vault along with two process

gas coolers. The off-Gas Vault Refrigeration System cools the four vaults in which the charcoal adsorbers are located. It is designed to maintain the temperature in the vaults at approximately 0 degrees F for maximum efficiency of the charcoal adsorption process. Each adsorber vessel has three thermocouples approximately equally spaced vertically through the charcoal vessels. (Emphasis supplied)

NRC Rpt., p. 3.

The OCA's Mr. Bridenbaugh ascribes 67 days of imprudent delay to the charcoal combustion events. In his opinion, the first fire (or combustion event) was the result of unreasonable management oversight and poor judgment, and the second by poor management oversight. Further, in his opinion, the Companies have failed to explain why and how the 67 days in question were used (OCA St. 7, [*21] pp. 30-35; OCA St. 7-1, pp. 1-2; Tr. 4685-4687; 385P-387P).

The Companies' response was presented in the rebuttal testimony of Mr. Frank R. Stead who replied in detail and sponsored CEI's response to the NRC report. In the latter, the response of CEI, it is conceded that the first combustion event could have been prevented by proper administrative controls for the use of space heaters. The response also disputes an NRC conclusion that CEI's response to the initial combustion was untimely but agrees that temperature data should have been reviewed more thoroughly and effectively (DLC St. 39/Penn Power St. 14, Attachment 1).

In his rebuttal testimony, Mr. Stead details CEI's response to detecting combustion in the adsorber vessel beds and states that the NRC was involved in every step of the process after the initial event. After combustion was detected, the heaters were removed and, after confirming high temperature, the air flow to the beds (part of the test) was stopped and a "nitrogen purge" of the charcoal beds was started. An unusual event was declared as of 11:45 A.M. on 6/20/86 and terminated as of 11:25 A.M. on 6/23/86 when all signs of combustion had ceased. The charcoal [*22] was sampled on 6/27/86 but otherwise a nitrogen atmosphere was maintained in the charcoal vessels to inhibit any further combustion. With the NRC's concurrence, the test was resumed on July 6, 1986, by reintroducing air to the vessels. When bed temperatures began to rise an hour later, a second unusual event was declared. The second combustion is attributed to one or more "hot" spots remaining in the charcoal. Subsequently all of the charcoal was removed, the vessels tested for any damage and refilled with new charcoal (DLC St. 39/Penn Power St. 14, PP. 3-9; NRC Rpt., pp. 9-12).

Mr. Stead testified that the charcoal combustion events had no effect on the critical path of the Perry project and, therefore, caused no extension of the Power Ascension program. The system being tested, the Off-Gas Processing System, is not used until the unit increases above 5% power. That power level was not exceeded until the Nuclear Heatup phase was commenced September 1, 1986. The Off-Gas Processing System tests were completed by August 21, 1986. The work that had to be completed prior to Nuclear Heatup was denominated Limatorque wire changes. (DLC St. 39/Penn Power St. 14, pp. 9-12). It [*23] should be noted that Penn Power disputed the OCA quantification of delay costs.

On this issue, the ALJ concluded:

The record here does not demonstrate that the Power Ascension Program was delayed by the charcoal combustion events. While costs were incurred as a result of an initial and improper use of space heaters, it is clear that these events cannot be translated into days of delay for the entire project. The OCA's proposed adjustment should be rejected. (Emphasis added).

In its Exceptions on this issue, OCA contends:

1. The Companies did not refute Mr. Bridenbaugh's conclusion that CEI was imprudent in its management of the events which gave rise to fires in the charcoal beds at Perry during June and July of 1986.
2. There was overwhelming evidence showing that CEI was delinquent in preparing the test procedures; CEI did not perform reviews in accordance with the safety classification of the equipment; and CEI's performance of the test was inadequate and ineffective.
3. The Companies' management of the events giving rise to the charcoal fires was imprudent which delayed the Perry power ascension program by at least two months.
4. The NRC issued a Confirmatory [*24] Action Letter, in which it stated that startup of Perry was not to occur without the NRC Regional Administrator, or his designee, reviewing CEI's recovery plan, and approving startup.
5. Startup was begun on September 1, 1986, 87 days after the first charcoal fire.

The Company responded to the OCA's Exceptions by again arguing that the charcoal combustion events, whatever their cause, had no impact on the critical path of the Perry Power Ascension Program.

We find persuasive the Company's argument that since the off-gas system is not required until operation above five percent power, the charcoal combustion events did not impact the critical path. We, therefore, deny the OCA's exception and adopt the recommendation of the ALJ on this issue.

(b) Reactor Core Isolation Cooling (RCIC) System Design and Operating Deficiencies

Mr. Bridenbaugh described the reactor core isolation cooling system as a ". . . backup emergency cooling system that is used for cooling the reactor core. . . ." It is not required to be in service at all times the reactor is in operation, but it shares controls and valves with the reactor containment system which must be operational (OCA St. 7, p. 36). [*25] He provided more detail on cross-examination:

Q. Now, on the next topic you discuss the reactor core isolation cooling system failures. Would you explain to us what the reactor core isolation cooling system is?

A. Yes, I do that very briefly on page 36. The RCIC system is a backup cooling system that is self-contained and is not dependent upon an outside source of electrical power for providing cooling to the reactor core under certain emergency circumstances. It consists of piping, valves,

control circuitry, a steam turbine and a pump, and the way it operates is to take steam, bleed steam off of the reactor, itself, run that steam through the RCIC system turbine, which turns a pump, which then pumps water back into the reactor vessel.

Tr. 3087-3088; 200P-201P.

Mr. Bridenbaugh reviewed Licensee Event Reports made by CEI to the NRC for 1986 and 1987 and discovered what he termed as numerous RCIC failures. He concluded that the failures demonstrated a repetitive and long-standing problem resulting from repetitive equipment failures, human errors and improperly prepared and implemented test instructions. He asserted that the Power Ascension Program was extended between [*26] Conditions 1 and 2 to take RCIC corrective action on a containment isolative valve, and that more work was required during the Condition 2 testing (OCA St. 7, pp. 36-39).

On cross-examination Mr. Bridenbaugh, although unable to quantify a delay in critical path requirements, insisted that an approximate one year time period for resolving RCIC problems was unreasonable. He did agree that most of the Licensee Event Reports he identified as relating RCIC problems dealt with one particular valve 51-F063. He was asked what could have been done about the valve:

Q. What was the problem with the valve?

A. I don't know that the company ever really figured out what was the problem with that valve. It was replaced and changed from --

Q. DC to AC, or vice-versa?

A. Yes; right, and it was changed from a normally closed to a normally open, or vice-versa. I have to look back and see.

Q. Do you have any views, yourself, as to what was wrong with that valve?

A. No, I have not. I just know that the RCIC system has been a system on boiling water reactors since BWR-2s, the Dresden 2 and 3 plants, and it's been around for a long time, and there isn't anything particularly innovative [*27] about this system, and for it to be troublesome for a year seems to me to be a demonstration that there was something wrong with the way the company was handling this.

Q. Could you tell us and the Commission what was wrong with what the company was doing?

A. The fact that they had repeated failures of this valve time after time and repeated problems with the tests that were being performed on it.

Q. What was the company doing wrong?

A. They were not getting to the bottom of this particular problem.

Q. What could we have done that we did not do?

A. I don't know. I don't know.

Tr. 3092-3096; 205P-209P.

Mr. Bridenbaugh proposed a prudence adjustment for RCIC of at least one month because of multiple equipment and human failures. He also emphasized that the RCIC system is not a new one and CEI should not have had as much difficulty with the system as it did (OCA St. 7, pp. 38-39; OCA St. 7-1, pp. 2-6).

The Company presented rebuttal in the form of the testimony of Mr. Michael D. Lyster, manager of the Perry Plant Operations Department. He agreed that the RCIC system has been in use in one form or another for quite a while, but asserted that the problems highlighted [*28] by Mr. Bridenbaugh concerned the Leak Detection System. He described the Leak Detection System as consisting of temperature, pressure and flow detectors used to detect abnormalities in the steam and water systems within the Reactor Building, Fuel Handling Building, Auxiliary Building and Steam Tunnel. He stated that the Leak Detection System is able to detect and identify abnormal flows, abnormal pressure and temperature changes in piping systems and surrounding rooms. It can also detect drain activity and abnormal radiation levels. To meet NRC requirements it is necessary to extensively fine tune and calibrate the system.

Mr. Lyster further responded in detail to assertions of Mr. Bridenbaugh concerning the RCIC system:

Q9. Mr. Bridenbaugh states on page 38, lines 8-10 of his direct testimony; "that seven RCIC isolations were reported in September and October, 1986". What were the cause of these isolations?

A. Initial operation is characterized by fine tuning, bringing the system back up for testing, down to fine tune, back up for testing, and fine tuning until the system is performing at its optimum level. During this shakeout of the RCIC system, interactions occurred [*29] that were not anticipated due to the Leak Detection System (E31) sending false isolation signals to the RCIC (E51) system. This resulted in extensive fine tuning, adjusting and some modifications to the Leak Detection System (E31). In addition, extensive tuning was required to the throttle valves on the RCIC system to accomplish an added NRC testing requirement for quick cold starts of the system. In conclusion, six of the seven isolations referred to were problems with Leak Detection System (E31) and not the RCIC (E51) system while the final isolation was due to the throttle valve fine tuning.

Q10. Mr. Bridenbaugh continues on to characterize "the RCIC system as being out of service an excessive amount of time" due to several reasons including "human errors, and improperly prepared and implemented test instruction" on page 38, lines 11-16 of his direct testimony. Is this true?

A. No. During the testing of the RCIC system and its interface with the Leak Detection System (E31), we had several instances where isolations occurred due to false signals coming from the Leak Detection system similar to those discussed above. However, if Mr. Bridenbaugh had closely reviewed the [*30] LERs that he listed, he would have discovered that of the five isolations that occurred during SVI testing, the longest isolation of the RCIC system was 30

minutes and the majority of the isolations only lasted about 5 minutes. More importantly, none of these events affected the plant status or any ongoing activities, subsequently [sic] they did not have a critical path effect. In response to the human errors allegation, again Mr. Bridenbaugh did not adequately review LER 87-87-029. If he had, he would have seen that the problem was due to an operator who had performed a RCIC maneuver and did not monitor how long the system was in that particular configuration as required by Tech Specs. The error was that the operator did not monitor the amount of time the system was configured this way and exceeded that time allowed. This operator error did not result in the RCIC system to be either isolated or inoperable. Therefore, these actions did not effect the operations of the plant and did not result in any delay of any sort. (Emphasis in the original)

DLC St. 41/Penn Power St. 16, pp. 5-6.

Mr. Lyster went on to discuss RCIC problems as identified by Mr. Bridenbaugh as occurring [*31] between Test Conditions 1 and 2, and during the Test Condition 2 outage. He agreed that the problem centered on the E51-F063 valve, the operation of which he described in detail. (Id., pp. 6-7) He disputed, however, Mr. Bridenbaugh's assertion that the problem had been occurring since September, 1966.

Q12. Mr. Bridenbaugh, in cross examination, said that E51-F063 problem has been occurring since September, 1986 (Duquesne Light Transcript, page 3094, Lines 8-21). Do you agree with what Mr. Bridenbaugh is saying?

A. No. The problem with E51-F063 did not appear until January 10 as stated in LER 87-003 and it's supplement. As I have previously explained, the events that occurred prior to this date that are addressed in the LERs Mr. Bridenbaugh has cited in his direct testimony were not RCIC problems but were due to fine tuning of the Leak Detection System. Therefore, they had nothing to do with the E51-F063 valve problem that is addressed in LER 87-003.

However, the problem with E51-F063 is identified on company's discovery response to Interrogatory 01-04 as indicated by Mr. Bridenbaugh in this excerpt and did result in the 23 days of delay during Test Condition 1.

DLC [*32] St. 41/Penn Power St. 16, p. 7.

Mr. Lyster detailed the investigation into the causes of the malfunctioning valve. He then summarized the results as follows:

In summary, the valve failed to operate properly eight times, was disassembled and all components inspected four times. Further the valve was tested five times, and the test results were reviewed by CEI, GAI, vendors, and consultants, but no conclusive evidence identifying a root cause was obtained.

DLC St. 41/Penn Power St. 16, p. 9.

In order to avoid a schedule delay, CEI requested from and was granted an amendment to its operating license by the NRC to allow low power operation of Perry without the RCIC system

working automatically. As the valve operation was not amenable to correction, the operation was re-engineered and modifications installed during the Pre-Test Condition 2 outage.

Q16. Was work on the RCIC valve the only reason for this outage?

A. No. In addition to the RCIC valve, this outage was needed to perform modifications to the B21 Vessel Level instrumentation as well as other equipment.

Q17. Was the work on the RCIC valve the critical activity?

A. At the beginning of the outage, this activity [*33] was concurrent with the B21 activities and several other items. Work on the E51-F063 valve was completed on March 30, 1987. The outage continued until April 10, 1987.

Q18. Do you agree with Mr. Bridenbaugh's assessment, "that the company never really figured out what was the problem with that valve" [Duquesne Light Transcript, page 3095, lines 9-11]?

A. Yes, We did everything possible to determine what the problem was. In addition to our effort, Gilbert, General Electric, the valve vendor, motor operator vendor and other consultants also participated in the investigation. During our investigation, we successfully eliminated almost every possible root cause that could have been responsible for the valve failure. This is best summarized as stated in the LER 887-003. "The cause of the valve and motor failures is indeterminate. Extensive testing and troubleshooting as a result of these events has not identified the root cause of these failures."

Q19. Do you agree with Mr. Bridenbaugh in his direct testimony on page 38, lines 17-19 that this indicates poor management?

A. No. Project Management utilized a logical progression of steps of troubleshooting and testing to isolate [*34] the root cause of the problem . . . (Emphasis in original)

DLC St. 41/Penn Power St. 16, pp. 9-12.

The ALJ concluded:

It thus appears that the proximate cause of the 23 day delay relied on by Mr. Bridenbaugh in his quantification was the erratic operation of a valve, required by NRC regulations and installed in the early 1980's. The erratic operation did not first occur until January, 1987. The record here does not support a conclusion that the 23 day delay was imprudently incurred. The problems with RCIC system in 1986 have not, on this record, been associated with any quantifiable delay. It is therefore concluded that the OCA's proposed adjustment associated with the RCIC system should be rejected.

The OCA excepted to these conclusions, arguing:

1. Although the RCIC system in place at Perry had been around for many years, the evidence discloses that Perry encountered many difficulties with this system.
2. A review of the numerous reports filed with the NRC concerning the RCIC system shows repetitive equipment failures, human errors and, as with the charcoal fires, improperly prepared

and implemented test instructions. These many deficiencies resulted in the [*35] RCIC system being out of service for an inordinate amount of time from January through May, 1987.

Extensive investigation and modification work was required as a result of these failures. OCA witness Bridenbaugh concluded that these failures represented inadequate management, and recommended that the costs of one month of delay caused by these failures be disallowed. (OCA St. 7 at 38-39.)

3. Problems with the RCIC system continued to plague Perry right up to the end of the power ascension phase.

4. The costs of the delay caused by management's failures with respect to the RCIC system should be disallowed. The cost to DLC for this delay is \$8.3 million, based upon a one month delay in commercial operation of Perry.

The Company responded to the OCA's Exceptions and stated that while the OCA talks about the fact that during the testing process the RCIC system was isolated or lost or unavailable or out of service or inoperable, it does not advise the Commission that this had nothing whatsoever to do with the testing program at Perry (Consol. Perry Init. Br. at 36-40; Consol. Perry R. Br. at 11-12).

The Company states that the one problem with the RCIC system which did impact [*36] upon the schedule related to a single valve. After extensive work, in which the Company, the architect/engineer, the manufacturer of the valve, and the NRC staff participated, the causes of the malperformance of that valve could not be ascertained and it was replaced (Consol. Perry R. Br. at 12). The Company also notes that when asked directly what the Company should have done other than that which it had done, the OCA's witness stated that he did not know.

We agree with the ALJ that although it appears that the proximate cause of the 23 day delay relied on by Mr. Bridenbaugh was the erratic operation of a valve, there is no evidence, however, that the Company was not prudent in its efforts to determine the cause of the valve malfunctions. Accordingly, no lack of prudence disallowance is proper. The ALJ's recommendation is adopted, and the OCA's exception is denied.

(c) Main Stream Isolation Valve (MSIV) Design and Operating Deficiencies

Mr. Bridenbaugh has proposed an adjustment for at least one and one-half months of delay due to repetitive problems with the main steam isolation valves (MSIV). He described the valves as being the eight valves in the main steam lines that [*37] connect the reactor and turbine and whose function it is to shut off the flow of steam from the reactor under emergency conditions. He stated further:

The MSIVs are an essential part of the containment isolation system. The MSIV problems are a continuation of generic BRW MSIV problems that have existed for some number of years. (Footnote omitted)

OCA St. 7, p. 39.

Mr. Bridenbaugh cited a portion of the PL&G Supplemental Report issued in August, 1985, and considered in the prior consolidated proceedings as showing some of the history of the MSIV problems both at Perry and in the rest of the nuclear power industry. The PL&G quote notes that the Perry MSIVs passed leak tests in 1985, but, Mr. Bridenbaugh notes, problems began again in July, 1987. Apparently problems persisted through the Summer and into the Fall of 1987 causing Mr. Bridenbaugh to conclude that the problem was not properly managed (OCA St. 7, pp. 40-42).

Mr. Bridenbaugh has provided the full text of the PL&G Supplemental Report section on MSIVs as Attachment 7 to OCA Ex. 7A. It is helpful to review the description of the valves given there:

1. MSIV Rework and Testing. At Perry there are four 26" Main [*38] Steam Lines that carry steam from the reactor to the turbine generator. On each line there are two MSIV's for redundancy, one inside the drywell and one outside the containment. The MSIV's are large -- about six feet long with a dry weight of 14,700 pounds. They are designed to close automatically on certain emergency signals and isolate the reactor from the outside environment. Through local leak rate tests, the MSIV's must be shown capable of containing high pressure with only minimal leakage. Given the high pressures, the large size and particular geometry of the MSIV's, and the exacting tolerances required, a number of utilities have had difficulties with their MSIV's. The utilities often found that the valve poppet did not fit tightly in the main valve seat, resulting in leak rate test failures. The reasons for the failures were not always obvious, and the Electric Power Research Institute has been performing tests and studies on behalf of the industry to determine the cause of the generic problem and to recommend solutions.

Mr. Bridenbaugh was questioned about the operation of MSIVs on cross-examination. He agreed that standards for leakage at the valves was established [*39] by the NRC and that meeting those standards has been a problem for the industry which has not been solved. His problem with CEI's performance at Perry is that it was not able to get through the Power Ascension Program without MSIV caused delay.

Q. And the failure of Cleveland Electric Illuminating Company to solve the problem which no one else has solved is [sic] as a result the disallowance; is that your testimony?

A. I think I won't speak for [sic] no one else having solved it, but there are a lot of other plants that have been able to get through their startup test program and not be affected like this.

Tr. 3097-3103; 210P-216P

Further on cross-examination, Mr. Bridenbaugh agreed that the MSIVs are tested every 18 months. The testing in the Summer of 1987 was conducted because the 18 month interval had run. He made no critical path analysis for the MSIVs because he was unable to obtain sufficient information. (Tr. 3104-3106; 217P-219P).

Mr. Bridenbaugh agreed that his 1 1/2 month delay quantification was derived from his reading of Mr. Kaplan's testimony (Tr. 4000; 213P; OCA St. 7, p. 41). His reference was to the following cross-examination of Mr. Kaplan on October [*40] 5, 1987:

THE WITNESS: A number of things do happen in the running of a test program. When the results are not what you anticipated you have to go back and analyze the test results, and you don't know when and where that will occur, so you can't specifically put those time frames in the plant sequence. Recently there has been some delay which occurred because of the leak testing of main steam line isolation valve due to the 18-month cycle coming up, and if you want I'll elaborate a little.

BY MR. SHIELDS:

Q. Yes, I would appreciate that. Thank you.

A. When you look at power ascension program, some power ascension programs are completed in a time frame that is before the 18-month required test cycle. Therefore, an outage takes place after the completion of the power ascension program in which the plant is taken down for a period of a couple of months, normally, and various 18-month surveillance tests are run. In some cases it's done before the completion of the power ascension program. At Perry this occurred before the completion of the power ascension program so we took an outage that was approximately a month and a half in duration and not just the main steam line isolation [*41] valves but numerous other systems that were required to be tested on an 18-month cycle were tested. That time frame took a little bit longer than we had expected. It's hard to estimate just how much rework will be required because this can't be done until the results of the leak rate testing are completed.

This type of testing is normally done at a plant during a refueling outage, but on a new plant startup the first fuel cycle is much longer than a normal fuel cycle because of all of the low power testing during the power ascension program. Therefore, your nominal 18 month cycle is not standard. Therefore, those various surveillance tests that have to be run on an 18-month period come up before the normal refueling outage, and I think this is consistent with what other plants have done around the country.

Q. Thank you for that elaboration. When you were discussing the main steam isolation valve difficulty you talked about a one and a half month outage attributable to that primarily?

A. That was one of the major work efforts that took place during that outage, but there were numerous other testings taking place during that same time period. (Emphasis added)

Tr. 1860-1862; [*42] 21P-23P.

The Company offered rebuttal to Mr. Bridenbaugh in the form of the testimony of Mr. Steven F. Kensicki, Technical Superintendent of the Perry Plant Technical Department. He provided additional information about MSIVs:

In a Boiling Water Reactor (BWR) such as the one at Perry, radioactive steam is produced in the Reactor Pressure Vessel (RPV) and flows through main steam lines to the turbine generator. At Perry, there are four 26" diameter main steam lines. Each line has two MSIVs, one inside and one outside the containment. At normal operation, the main steam lines pass approximately 15,000,000 pounds of steam per hour at 550 degrees F. and 965 psi.

The eight MSIVs are spring loaded, pneumatic piston operated globe valves which are normally opened but designed to close in 3 to 5 seconds upon either (a) closure signal from plant control systems or (b) loss of pneumatic pressure or power to the valve control system.

Under fast closure condition, the spring force creates a metal to metal, seat to poppet impact of approximately 40,000 pounds. Per Tech Spec requirements, the MSIVs has a penetration allowable leak rate of 25 standard cubic feet per hour (a penetration [*43] is defined as the loss per line through the containment including both the inboard and outboard MSIV).

DLC St. 37/Penn Power St. 12, pp. 3-4.

Mr. Kensicki agreed that MSIVs have been a challenge to the industry and, despite decades of effort, have not been significantly improved. He outlined steps CEI has taken to minimize problems with the MSIVs and then reached the crux of the issue when he discussed the local leak rate tests (LLRT) which must be conducted every 18 months. The first repeat LLRT was due in May, 1987, which CEI succeeded in postponing to July 1987, so that the LLRTs on all MSIVs could be conducted in one outage. The outage schedule anticipated the rework of one MSIV within a 21 day period; the actual outage covered 51 days during which a total of six MSIVs were reworked and retested over a 34 day period. He provided a very detailed outline of the work required on the MSIVs and stated his opinion that the work was necessary and was accomplished in a timely fashion (DLC St. 37/Penn Power St. 12, pp. 4-13).

Mr. Kensicki disputed Mr. Bridenbaugh's conclusion concerning CEI's management of the MSIV's by detailing steps taken to minimize delay. He noted that [*44] six times the amount of work was accomplished in only three times the amount of time allocated (DLC St. 37/Penn Power St. 12, pp. 14-15).

On cross-examination, Mr. Kensicki related that the then current outage at Perry was caused by the failure of a valve that is, in turn, part of the control system for the MSIV system. The problem or failure did not relate to the MSIVs themselves. He provided additional information on the work done on the MSIVs (6 out of 8) in the Summer of 1987 and noted they would be tested again at the next test interval (Tr. 4581-4593; 294P-306P).

On surrebuttal Mr. Bridenbaugh sought to direct attention to CEI's management of MSIV problems. He opined that CEI had only applied three out of eleven recommendations made by a industry owner's group which has focused on the MSIVs' problems. He again stated that his 1 1/2 month delay calculation was based on Mr. Kaplan's testimony. On cross-examination he could not be specific as to dates of delay but judged that the delay occurred over the period of July through October, 1987 (OCA St. 7-1, pp. 6-11; Tr. 4698-4709; 399P-409P).

Mr. Kensicki presented oral rejoinder testimony to the effect that, of the eleven [*45] recommendations made by the owners group, two are not applicable to Perry, eight were attended to during the 1985 outage and all nine were considered during the 1987 outage. The one not considered in 1985 was a closing procedure which required conditions not available in 1985. On cross-examination he pointed out that the MSIVs are subject to a great deal of stress, and even more during startup testing than during normal operations (Tr. 4730-4734; 430P-434P).

Based on the record, as recounted above, the ALJ concluded that the OCA's proposed adjustment for this issue should be rejected.

The OCA excepted to the ALJ's recommendation as follows:

1. MSIV problems are not unique to Perry, such problems have been occurring for years.
2. The Company was unable to prevent continuing and costly MSIV problems during the final stages of the power ascension program, adding at least 1 1/2 months of avoidable delay in the project, at a cost of \$12.4 million.
3. Just because a particular problem is present at other plants in the industry does not relieve the utility of the burden of proving that its response to the problem has been reasonable.
4. The Company's management of the MSIV [*46] problems at Perry was imprudent.

The Company responded to the OCA Exceptions, with the following points.

1. There is no question but that everyone has had problems with MSIV leakage.
2. The Company acted in a reasonable manner in its efforts to correct or solve the MSIV leakage problem.

We agree with the OCA that simply because a particular problem is present at other plants in the industry does not relieve the Company of the burden of proving that its response to the problem has been reasonable. However, we do not agree with the OCA that the company acted in an unreasonable manner in attempting to correct the MSIV problem. The testimony on this issue clearly establishes that the MSIV's have been a problem to the industry generally and that the problem has not yet been resolved. The Company established by the testimony of Mr. Kensicki that the work required on the MSIV's was necessary and was accomplished in a reasonable time. The Company acted in a reasonable manner which precludes a finding of imprudence. Accordingly, the recommendation of the ALJ is adopted, and the OCA's exception is denied.

(d) Personnel and Procedural Errors

In his direct testimony Mr. Bridenbaugh [*47] stated that a review of Licensee Event Reports (LERs) made to the NRC indicated a high number of problems resulting from human error or inadequate procedures. He stated he would need additional information to formulate any recommendation (OCA St. 7, pp. 42-43).

Mr. Bridenbaugh quantified his delay allowance for this category as follows:

The fourth category includes personnel and procedure errors. I have no way of quantifying this category without the additional information that was requested. Until it is provided, it must be treated as an unknown portion of the remaining scheduled extension amount of 6 to 8 months. In the interim period, I recommend disallowance of costs associated with 3-1/2 months of the ten month power ascension program extension.

Q. What is the basis of your 3-1/2 month cost allowance?

A. The power ascension program was extended by at least ten months. I have recommended disallowance of 4-1/2 of the ten months. An additional two months (approximate) can be attributed to the FPOL Stay and to the addition of Test Conditions 7 and 8. Thus, there are 3-1/2 months of delay in the power ascension program completion which have not been adequately explained [*48] by the Company.

OCA St. 7, p. 47.

Mr. Bridenbaugh was cross-examined on his testimony and, particularly on Attachments 3 and 8 to OCA Ex. 7A. Attachment 3 is a 15 page chronology of events occurring at Perry based on Mr. Bridenbaugh's review of CEI LERs. Attachment 8 is a bar graph seeking to compare causes for LERs. He agreed that the bar graph showed a declining number of procedural and personnel errors. He also conceded that errors in coding could have occurred in his method which involved using a computer data base to obtain the information presented in the two attachments (Tr. 3106-3118; 219P-231P).

Ms. Eileen M. Buzzelli, General Supervising Engineer of The Licensing and Compliance Section presented rebuttal testimony directed to showing increased NRC activity at Perry and details on the Licensee Event Report System at Perry with the goal of rebutting Mr. Bridenbaugh's testimony on personnel and procedural errors. The latter matter will be addressed here with the former reserved for later discussion.

Ms. Buzzelli described CEI's handling of "plant concerns". Every abnormal condition or event is evaluated for reportability. If considered reportable, an LER is [*49] prepared. She detailed the method of preparation and noted that the NRC had specifically noted the lack of repetitive personnel errors. She discussed the results of an analysis of all of the LERs with a cause code of personnel or procedural error. The conclusion was that a total of eight days of delay could be attributed to personnel and procedural errors. The LERs were specific and discussed. She disagreed with Mr. Bridenbaugh's conclusions and stated her opinion that:

Management attention and actions in this area have been comprehensive and have resulted in effective corrective actions with minimal impact to the project schedule.

DLC St. 36/Penn Power St. 11, pp. 5-8.

Mr. Bridenbaugh did not agree with Ms. Buzzelli and offered an analysis of LERs from other nuclear plants during startup as support for his position (OCA St. 7-1, pp. 15-17). On cross-examination he agreed that his comparison plants listed differed from other lists used for other purposes. He also agreed that at least some of the listed plants were not yet in operation and some were the second unit to be built at the same site. He also agreed that some data had been omitted and that the omitted data [*50] could change the results but not skew it (Tr. 4721-4728; 421P-428P).

The ALJ concluded:

OCA did not initially state, through Mr. Bridenbaugh, that it could demonstrate a 3 1/2 month delay resulting from personnel and procedural errors. By the close of the testimony, OCA was

reduced to presenting a comparison study which, frankly, has little or no relevancy to the events occurring at Perry. Ms. Buzzelli's testimony, on the contrary was concrete and to the point raised by Mr. Bridenbaugh. Her testimony was available for testing and is unrefuted in this record. It is concluded that no material delay resulting from personnel or procedural errors has been demonstrated on this record. Accordingly, the OCA's adjustment should be rejected.

The OCA, in its Exceptions to the ALJ's recommendation regarding the issue of personnel and procedural errors, repeated most of its argument presented in its Brief. Specifically, the OCA argued:

1. Perry's power ascension program was plagued by numerous personnel errors, inadequate test procedures and inadequate surveillance and test instructions. The OCA would attribute a 3 1/2 month delay to the Company.
2. Perry had an average of five [*51] LERS per month caused by personnel or procedural errors, which exceeded the comparable monthly figure for every other similar plant. In absolute terms, Perry's personnel and procedural errors during power ascension exceeded industry average by almost 50%.

The Company, in its Reply Exceptions contended;

1. The question is not whether Perry had more human errors and/or procedural problems, but how CEI managed these problems.
2. The NRC found that CEI did not have repetitive personnel errors at Perry, to wit:

Perry Management has consistently focused attention and evaluated methods to ensure continued quality and to institute additional improvements in this area (Training and Qualification Effectiveness) when felt warranted. In addition, thorough evaluations of personnel error related problems were conducted from the standpoint of training and qualification effectiveness, and the lessons learned were disseminated to all personnel performing related functions. As a result, licensee has achieved a general lack of repetitiveness in personnel error related events.

Dug. St. 36 at 6-7; Penn Power St. 11 at 6-7 (quoting NRC Systematic Assessment of Licensing Performance No. 7). [*52]

We concur with the recommendation of the ALJ and, accordingly, deny the OCA exception.

(e) Miscellaneous

Mr Bridenbaugh developed a broadly stated set of standards for evaluating CEI's performance during the startup phase at Perry. In applying those standards he reached general conclusions coinciding with the four previously discussed specific areas as additional support for finding a total of 8 months of imprudent delay in the Perry Power Ascension Program. Quantifying the costs at \$2.01 million per day and alleging 240 days of delay, the OCA recommends a prudence disallowance of \$483 million. Penn Power's 5.24% share is \$225.3 million (OCA St. 7, pp. 43-48).

The response to Mr Bridenbaugh's testimony is contained in the rebuttal testimony of four witnesses for the company which will be outlined briefly here.

Ms Gwendolyn K. R. Luciano, Project Controls Systems Supervisor in the Outage Planning Section of the Perry Plant Operations Department, provided a schedule analysis for Test Conditions 6 through 8. As she noted, the analysis from Fuel Load to the start of Test Condition 6 is contained in Attachment 2 to OCA Exhibit 7A. She offered one change to the latter analysis. [*53] Taken together the two summaries provided an accounting for the critical time path through the Power Ascension Program. (DLC St. 38/Penn Power St. 13, pp. 1-4).

Ms Luciano then proceeded to review the schedule in detail. For example, when the reactor was unexpectedly shut-down ("unplanned manual reactor scram") due to a generator coolant leak, it was decided to accelerate an outage planned for July 12 to July 1, 1987. During the resulting 51 days outage the Local Leak Rate Testing of the MSIVs, as previously discussed, was performed as well as numerous other items. (DLC St. 38/Penn Power St. 13, pp. 5-7). Ms. Luciano then explained how the number of days allocation was developed and quantified. It is important to note that the critical path analysis is the starting point for the analysis performed by Mr. Bridenbaugh (DLC St. 38/Penn Power St. 13, pp. 7-10, ATTMT. 1).

Mr. Gary R Leidich, General Supervising Engineer of the Outage Planning Section at Perry, presented testimony to rebut allegations that expanded work scope and equipment modifications had not been shown to be responsible for extension of the Power Ascension Program schedule. He provided a detailed listing [*54] of the expanded work and equipment modifications required in the context of the critical path analysis found in Appendix 2 to OCA Ex. 7 and as sponsored by Ms. Luciano (DLC St. 40/Penn Power St. 15, pp. 1-5).

Mr. Leidich described expanded work scope as four kinds of actions, including operating improvements, increased regulatory requirements, the creation of additional Test Conditions 7 and 8 for testing the Maximum Extended Operating Domain (MOED) and completion of mandated repetitive tasks. He characterized the additional work scope projects as affirmative steps to improve performance; equipment modifications, including calibration and repairs, were labeled as reactive or as being made as needed. He then provided detail on examples of expanded work scope projects which extended the length of the Power Ascension Program. One example was the change to a new neutron source mentioned by Mr Kaplan in his direct testimony. Others were changing electrical connections to easier to use modular ones, improved controls for the diesel generators, a change in the safety related air system from high to low pressure to prevent future delays, and a change in the non-safety instrument air [*55] system from copper tubing to stainless steel (DLC St. 40/Penn Power St. 15, pp. 5-8).

As to the second category, increased regulatory requirements, Mr. Leidich noted numerous examples. He specifically addressed extensions resulting from increased NRC scrutiny given to an item called "Limitorque Motor Operator". (DLC St. 40/Penn Power St. 15, pp. 8-10).

In the third category, the addition of Test Conditions 7 and 8, Mr. Leidich referenced the testimony of Mr. Stead on the addition of the MEOD program. The purpose of the additional testing was to "validate" Perry for operation over a broader range of core coolant flows and

reactor rod positions than that originally planned. CEI performed a cost/benefit analysis prior to purchasing MEOD and concluded that the program would enable Perry to more economically utilize its fuel load without violating any operating specifications or guidelines. Mr. Stead referenced other plants using or planning to use MEOD (DLC St. 40/Penn Power St. 15, pp. 10-11; LCD St. 39/Penn Power St. 14, pp. 13-15; Penn Power ST. 8, pp. 8-9).

As to the fourth category, periodic testing or "repetitive tasks", Mr. Leidich pointed out that as the Power Ascension [*56] Program extended, work scheduled at 12 or 18 month intervals became due. These tasks were not included in the original schedule and were to be accomplished after completion of the Power Ascension Program. Besides the periodic testing, preventive maintenance work was required. As noted earlier, the inspection of the MSIVs came due during the Power Ascension Program (DLC St. 40/Penn Power St. 15, pp. 11-12).

Mr. Leidich then proceeded to provide detailed examples of equipment modifications performed during the Power Ascension Program. He then provided his opinion concerning assertions made by Mr. Bridenbaugh:

Q. Do you agree with Mr. Bridenbaugh's conclusion on page 27, lines 5-8; "equipment modifications led to delay but much of the delay should have or could have been avoided"?

A. No. First Mr. Bridenbaugh makes this statement yet does not support it with any examples except for the allegations concerning the RCIC system and MSIVs. Even considering these few equipment modifications, he does not supply how or why these could have been avoided in either this direct testimony or cross examination.

The concept of avoiding equipment modifications is inconceivable. The purpose [*57] of performing the power ascension program is to stress the various components that makeup the Perry Nuclear Power Plant to demonstrate that the plant functions as designed and operates safely. Even Mr. Bridenbaugh agrees that this is the purpose of the power ascension program [Direct Testimony, page 6, lines 9-11; Duquesne Light Transcript page 3034, lines 18-25 & page 3035, lines 1-7]. And everyone agrees that equipment modifications will occur [Direct Testimony, page 27, lines 1-3]. Further, everyone agrees that equipment modifications cannot be predicted in regards of when they will occur [Duquesne Light Transcript, page 3070, lines 23-25] or how many will occur [Duquesne Light Transcript, page 3070, lines 15-21]. So the statement made by Mr. Bridenbaugh that "unplanned delay periods such as that resulting from the Court Stay should have been utilized to reduce the potential expanded works scope" [Direct Testimony, page 27, lines 15-17] as support for "much . . . of the delay could have been avoided" is in direct contradiction with his cross examination. How was CEI to utilize the delay due to the Court Stay to prevent an equipment modification if operation above 5% power [*58] had not identified the need yet.

Q19. Do you agree with Mr. Bridenbaugh's conclusion on page 26, lines 11-13; "Thus, since the number of open items was reduced to a very low level before fuel load the work scope after fuel load should have been shorter."?

A. No. Because the NRC had required such a low number of open items prior to fuel load, management prepared the power ascension schedule with very little contingency for bulk work scope items identified during plant testing and operations. This was consistent with our philosophy of tight but achievable scheduling. When any change or modification was required, the probability of any single expanded work scope item or equipment modification impacting the critical path of the schedule was high. This was discussed extensively by Mr. Kaplan in his Penn Power Testimony (Statement No. 8) on pages 15-16.

Q.20. Do equipment modifications in and of themselves indicate management imprudence?

A. Absolutely not. The testing of a plant as large and complex as a nuclear powered generating station, involves thousands of components interacting and working together. Operation of that equipment is in accordance with tens of thousands [*59] of pages of instructions and procedures. The power ascension period is the first opportunity to operate, stress, and utilize all of the equipment and systems working together. It is difficult to anticipate what changes and adjustments might be required and when they might be required. (Emphasis in original)

DLC St. 40/Penn Power St. 15, pp. 12-18.

Ms. Eileen Buzzelli, whose testimony was referenced earlier, provided rebuttal testimony on increased regulatory involvement by the NRC at Perry. She cited examples of the NRC referring to problems at other plants as reasons for imposing a closer scrutiny and an "extra" regulatory involvement at Perry. As a result of heightened NRC review, CEI has taken a cautious approach with the goal of avoiding penalties and maintaining credibility with the NRC. She explained the abnormal event or condition reporting program, as noted earlier. Finally she recounted that the NRC has found and stated that CEI has avoided repetitiveness in personnel error problems and has been conservative in reporting problems and events (DLC St. 36/Penn Power ST. 11, pp. 1-7).

Ms. Eileen M. Mulroy, an Associate Rates and Technical Studies Analyst for the [*60] Centerior Service Company, provided rebuttal testimony on the quantification of delay costs. She also sponsored Joint Utility Cross Examination Exhibits A through J. First, she described how the \$2.01 million per day was developed; essentially, budget data for the period May, 1987, through September, 1987, including capital, expense and AFUDC were summed and divided by 153 days. The resulting figure represents the average projected costs to run the Perry plant during the period selected (DLC St. 33/Perry Power St. 10, pp. 2-4, Appendix 1).

Ms. Mulroy then criticized the figure as representing costs that would have been incurred whether Perry was operating commercially or not; the figure does not quantify the cost of any delay that occurred. She asserted that any event deemed imprudent should be quantified in terms of the actual additional costs incurred as a result. She provided specific calculations of additional costs incurred as a result of the "charcoal event", \$411,137.00; the "RCIC system failure", \$119,448.00; and the MSIVs Problems, \$819,689.00 (DLC St. 33/Penn Power Ct. 10, pp. 3-7).

Ms. Mulroy then provided revised versions of Joint Utility Cross Exhibits A through [*61] J. She provided references to the sources of the documents. The documents demonstrate the effect

on statistics and conclusions resulting from using different groupings of other nuclear plants. She concluded by opining that comparative analyses is inappropriate to use for evaluating management prudence (DLC St. 33/Penn Power St. 10, pp. 5-8).

Mr. Bridenbaugh responded briefly to the rebuttal testimony reviewed above. He complained that the examples presented by Mr. Leidich of equipment modification and expanded work scope were not disclosed by Mr. Kaplan or during discovery. However, he stated that he continues to maintain that some equipment failures were repetitive and should or could have been avoided by prudent management (OCA St. 7-1, pp. 11-13).

Mr. Bridenbaugh found fault with Ms. Buzzelli for stating the obvious regarding NRC regulation and continued to fault CEI for not being better prepared to deal with the NRC reviews. He apparently believes that the institution of the Systematic Assessment of License Performance program by the NRC in 1980 should have put CEI on notice to prepare for increased regulatory involvement. As to his position that repetitive personnel [*62] and procedural errors occurred and evidenced imprudence, he found no counter-weight in Ms. Buzzelli's rebuttal. He again reviewed his statistical sampling of reported events from other plants as support for his proposal 3 1/2 month delay disallowance (OCA St. 7-1, pp. 13-17).

As to Ms. Luciano's testimony, Mr. Bridenbaugh noted that her statement that Test Conditions 7 and 8 added 24 days was close to his estimate of three weeks. These three weeks were part of the total of two months of delay, including the stay of the full power license, that he found unavoidable (OC St. 7-1, p. 17; OCA St. 7, pp. 46-47).

On cross-examination Mr. Bridenbaugh agreed that he now accepted that radiant heaters did not cause the second combustion event and that no significant amount of heat was applied prior to or during the second event (Tr. 4683-4685; 383P-385P). He agreed that Attachment 2 to OCA Ex. 7 and Ms. Luciano's testimony listed the 67 days of delay he found resulting from the charcoal events on June 23 and July 6, 1986, but asserted no reasons for the time spent are given. He agreed that the work listed was performed (had to be performed) and that it took the time listed, but countered [*63] that the amount of time used was not explained (Tr. 4685-4687; 383P-387P).

Further on cross-examination, following a discussion of previously related issues, Mr. Bridenbaugh stated that Ms. Luciano's testimony confirmed a 60 some day delay attributable to MSIV work. He agreed, he went through her testimony and pulled out every reference to MSIVs to reach a total of 63 days. He agreed that the 18 month test was included in the total, and would have had to be performed (Tr. 4705-4709; 405P-409P).

Cross-examination then covered Mr. Bridenbaugh's use of LERs and other information obtained from the NRC. He agreed that work orders and other documents prepared for the Power Ascension Programs would number in the thousands. He agreed that he knew problems had arisen at operating Fermi 2 after the NRC granted a license and that the NRC was determined not to be embarrassed again. He was unsure of the exact dates and sequence of events, but the problems began in 1985, and Fermi 2 had not yet loaded fuel. Following a series of questions on the effect of scheduling decisions, the following discussion ensued:

Q. Let's go back to my original question. Whether we are talking about Ms. [*64] Luciano or not, how would you schedule for what you have called regulatory evolution?

A. I think that whether or not I schedule for it or put it in the reference schedule is not the issue. I find no fault in the company adopting an optimistic schedule or trying to meet an optimistic schedule. I think that is a very desirable thing to do.

But I do not find fault with after the fact looking at a start-up that has been delayed by at least six months, ten months, or whatever -- at least ten months, or whatever the time period has turned out to be -- I guess it's approximately ten months -- and then saying that the reason it was delayed because of regulatory matters that were entirely outside the control of the company.

I think the company is obligated to foresee such things as the change in emphasis that the NRC is going to make as more and more plants become operational and as more and more operational experience is obtained and to act aggressively to prevent or forestall such activities from stretching their program out.

Q. How are we going to forestall the NRC from anything?

A. By being ahead of them, if you will, by anticipating what they are going to want to see and [*65] by trying to take action to be able to answer the questions that they have.

Q. It's not easy, is it?

A. It's not easy. Definitely not. But some people do it.

Q. Who, for example?

A. Well, I can think of recently, the Hope Creek plant was started up in less than what had originally been estimated in terms of their start-up test program completion.

Q. That is the case off New Jersey where you testified that the company's proposed schedule was overly optimistic, isn't it?

A. That's correct. And they surprised me. They pulled it off.

Q. Would you agree with me that it's better to attempt to make a tight and optimistic schedule than to go to the craft union and say we hope you can get it done in the next few years?

A. I would agree. (Emphasis Added)

Tr. 4719-4721; 419P-421P.

The cross-examination then pursued the selection of plants to compare to Perry. Mr. Bridenbaugh agreed that omitting a month's worth of data could change the date but not change the results. He stated his unwillingness to accept Ms. Buzzelli's report or her analysis without additional support. He agreed that reviewing all the LERs could be onerous and that supporting documentation [*66] could fill the room (Tr. 4722-4728; 422P-428P).

(f) Recommendation of the ALJ

Following is the recommendation of the ALJ:

The initial presentation of the companies included the two statements of Mr. Kaplan and the partial critical path analysis provided to OCA on discovery. Although brief, the statements of Mr. Kaplan present a remarkably complete review of the period under review and provide an accurate summary and assignment of events and causes for the length of the Power Ascension Program.

As reviewed earlier, OCA has targeted three equipment or hardware areas for close scrutiny. It was concluded earlier that no quantification of delay could be assigned to the "charcoal combustion events", "RCIC problems," and "MSIV problems". The personnel and procedural errors area presents somewhat different considerations.

By comparisons with the experience at other plants, OCA has sought to portray CEI's management as laggard and not able to adequately anticipate problems. Further, CEI has been portrayed as prone to repeat mistakes due to inadequate management. Treating the second matter first, the regulatory agency closest to the scene has rendered a different judgement on the [*67] matter. In its SALP 7 report the NRC concluded that CEI has avoided repetitiveness of personnel errors. As to the former matter the NRC found CEI to be "conservative" in reporting problems (DLC St. 36/Penn Power St. 11, pp. 6-7).

The problem with making comparisons always amounts to what exemplar does one choose as the model. Without delving into the details, the record here demonstrates that the selection process clearly affects the data that results. It is not suggested that a comparison standard could or should never be used in a prudence review. It is stressed that data used for comparison purposes must be developed to a point of being truly comparable. For example, the record is silent as to the NRC's assessment of the reporting philosophy of the managements of units cited for comparison purposes. No attempt is made on this record to develop in some detail the similarities (or lack thereof) in schedule, start-up procedures, stage of completion or any number of other specific areas to the comparison plants beyond a very gross classification by time frame, plant type and licensing stage.

As this Commission agreed in the last cases, and it bears repeating:

Prudence is [*68] not perfection. Imprudence cannot be inferred because the achieved result fell short of expectations. Pa. P.U.C. v. Penn Power Co., 85 PUR 4th at 335.

The standard, then, is not perfect foresight and perfect performance. One test ought to be, and the one the OCA properly applied, is that when mistakes occur, has CEI (and the companies) demonstrated the ability to learn from the mistakes and take steps to avoid repeating them. The record here, contrary to the assertions of OCA, demonstrates that CEI managed its errors quite well.

The record here also establishes that the level of NRC scrutiny increased over the period in question. Surely a number of reasons were present. Problems at another plant, Fermi 2, which had embarrassed the agency. Public concern over the safety of Perry. The increased attention occurred. CEI chose to take non-adversarial approach and made a priority of addressing each and

every NRC concern. Whether this approach lengthened or ultimately shortened the amount of time consumed is a speculative question. It is an approach which even Mr. Bridenbaugh does not fault; he faults CEI for not doing a better job of anticipating NRC concerns. However, CEI [*69] tried to anticipate, and tried to head off problems as they arose. It is difficult to conceive as to how such conduct can be deemed to be imprudent.

Public fears were manifested in the litigation that resulted in a federal court staying the issuance of a full power license by the NRC. The result was that CEI could not exceed a 5% power level for an extended period of time. It is difficult to quantify the effect that stay had on operations; it was surely more than the month granted by Mr. Bridenbaugh. Part of the difficulty was not in knowing when or if the stay would be lifted (Tr. 1894-1897; 55P-58P). The 5% power limitation was formally in effect from September 4, 1986, to December 23, 1986. The federal court order in CEI's favor was not entered until March 17, 1987 (OCA Ex. 7A, Attachment 3, pp. 7-11). Again, it is difficult to ascertain the effect such uncertainty has on a project as complex as that at Perry.

The conservatism of CEI in testing at Perry is evidenced also by its decision not to consider the full power testing in June, 1987, as the warranty run. It might also be remarked, as has not been by any party here, that apparently no significant event or failure [*70] resulted when an earthquake of significant force occurred on July 13, 1987, about 20 miles from Perry.

Both the Companies and the OCA (which as shouldered the task for Complainants) are somewhat hampered in their respective presentations by a lack of updates to the prodigious studies produced by Pickard, Lowe & Garrick and the Touche Ross group in the prior cases. That lack is somewhat mitigated by the facts that the period being considered is somewhat shorter and covers only one phase of Perry's construction.

The ALJ concluded:

The question presented, then, is whether the companies on the record here developed have satisfied their statutory obligation to adequately explain the difference between the original cost estimate and the final one. It is recommended that this Commission conclude that the burden has been met and, as a result, make no prudence [sic] adjustment.

We concur with the recommendation of the ALJ that no prudence adjustment should be made.

B. Excess Capacity

In a prudence review, the focus of the inquiry is on the reasonableness of a utility's decision at the time and in the context when the decisions were made. In resolving the question of excess [*71] capacity, light is shed upon the utility's existing, available capacity in relationship to its present and future load requirements. In this regard, an adjustment based on a determination that a utility has excess capacity is proper, even though all or part of the cost of constructing the plant (s) which result in excess capacity have been deemed to have been prudently incurred. *PECO v. Pa. P.U.C.*, 61 Pa. Cmmwth. Ct. 325, 433 A.2d 620 (1981); *PP&L v. Pa. P.U.C.*, Pa. Cmmwth. Ct. , 516 A.2d 426 (1986).

In resolving the question of whether a utility has excess capacity, there are certain legal standards to be applied. We shall review these standards prior to discussing the evidence on this issue.

1. Legal Standards for Determining Excess Capacity

The legal standards applicable to an excess capacity adjustment are codified in Section 1323 of the Code, 66 Pa. C.S. § 1323. In pertinent part, this Section provides:

(a) Excess capacity costs -- Whenever a public utility claims the costs of an electric generating unit in its rates for the first time and the Commission finds that the unit results in the utility having excess capacity, the Commission shall disallow from the [*72] utility's rates, in the same proportion as found to be excess capacity:

- (1) the return on a specific unit or units of any excess generating reserve;
- (2) the return on the average net original cost per megawatt of the utility's generating capacity; or
- (3) the equity investment in the new unit.

In addition to the disallowances set forth in this subsection, the Commission may disallow any other costs of the unit or units which the Commission deems appropriate. For the purposes of this section, a rebuttal presumption is created that a unit or units or portion thereof shall be determined to be excess unless found to be needed to meet the utility's customer demand plus a reasonable reserve margin in the test year or, if it is a base load unit, it is also found to produce annual economic benefits which will exceed the total annual cost of the plant during the test year or within a reasonable period following the test year.

The statute and its application have been interpreted to require, basically, a three step procedure on the part of the Commission where a utility has requested rate base treatment of new base load units. First, the Commission must determine whether the additional [*73] new unit will create excess physical capacity. The test used for excess physical capacity is defined as the statutory presumption, supra, that the new unit is excess unless found to be needed to meet the utility's customer demand plus a reasonable reserve margin.

If the first test is passed, then the Commission must determine if the new baseload unit will result in excess economic capacity. The test for excess economic capacity is whether the new base load plant is found to produce annual economic benefits which will exceed the total annual cost of the plant during the test year or within a reasonable period following the test year.

The third step in the process requires the Commission to impose remedies found in Section 1323 (a) (1), (2) or (3) if the new plant results in excess physical or economic capacity.

2. Excess Physical Capacity

As stated above, the test for excess physical capacity requires the utility to rebut the presumption that the new plant is not required to meet the utility's customer demand plus a reasonable reserve margin. In this regard, the analysis requires: (1) determining a reasonable reserve margin; (2) specifying which plants or parts of plants [*74] are to be counted in computing installed or available capacity; and (3) determining whether all the installed or available capacity is needed

to meet the utility's (peak) customer demand plus a reasonable reserve margin in the test year or the year following the test year. Pa. P.U.C. v. Duquesne Light Co., R-860378.

The Company proposed that a reasonable reserve margin for its system consisted of a range between 25% to 35%. This range was determined by evaluating Penn Power's projected load growth, large industrial load, high load factor, variation in months and hours of peak loads, the size of generating units compared to total capacity, generation mix and transmission capabilities.

The Office of Trial staff (OTS) witness concluded that a 23% to 34.5% range constituted a reasonable reserve margin for Penn Power. The witness deemed this range of reasonable reserve margin appropriate because the Company's load growth occurs in relatively small annual increments while capacity additions result in larger, lumpier increments.

The Office of Consumer Advocate (OCA) witness stated that a review of the Ohio Edison reliability model confirmed his own modeling results and argued for [*75] a reasonable reserve margin range of 15-19%. The OCA's position is that the Company does not require a reserve margin in excess of 20% in order to provide reliable service.

The ALJ recommended that, for the purpose of this case, the Commission adopt a reasonable reserve margin of 34% for Penn Power.

The second portion of our analysis requires the determination of the Company's installed or available capacity. In this regard, the Company claimed a total net dependable generating capacity from jointly or solely owned plant of 907 MW. For the excess capacity determination, the Company reflected the impacts of seasonal deratings and several sale and purchase power arrangements.


Two sales arrangements, with the Potomac Edison Power Company (PEPCO) and General Public Utilities Corp. (GPU), totaling 49 Mw, have been included in the Company's load forecast. Additional sales to PEPCO under a firm, long term contract, starting with 28 Mw presently, increasing by 14 Mw on January 1, 1989, and 21 Mw on June 1, 1989, have been "removed" from all claims in this proceeding. Additionally, on an annual basis, Penn Power enters into sale and purchase of power arrangements with its parent, [*76] Ohio Edison.

The Company's position on peak loads, peak reserves and reserve margins can most easily be grasped by presenting two tables from the filing, updated and slightly annotated. The first table presents the Company's calculation of its net capacity for the years 1987 through 1996. The heading NDC represents net dependable capacity. The column headed OVEC indicates anticipated purchases from the Ohio Valley Electric Cooperative (See PP St. 1, p. 16). The next column, seasonal derating, adjusts when the Company's peaks occur. The next two columns reflect adjustments for sales to Ohio Edison and PEPCO.

PENNSYLVANIA POWER COMPANY

Generating Capacity

At Time of Peak

Year	NDC	OVEC	Seasonal Derating	OE Sale	PEPCO	Net Capacity
1987	844	17	(16)	(38)	(28)	779
1988	907	11	(15)	*  (21)	(28)	854
1989	907	5	(15)	(26)	(63)	808
1990	907	5	(15)	(30)	(63)	804
1991	907	5	(15)	(32)	(63)	802
1992	907	5	(15)	(35)	(63)	799
1993	907	5	(15)	(37)	(63)	797

PENNSYLVANIA POWER COMPANY

Generating Capacity

At Time of Peak

Year	NDC	OVEC	Seasonal Derating	OE Sale	PEPCO	Net Capacity
1994	907	5	(15)	(43)	(63)	791
1995	907	5	(15)	(47)	(63)	787
1996	907	5	(15)	(53)	(63)	781

[*77]

The next table sets forth the Company's calculation of peak reserve in Mw and percentage. It also presents a calculation of the reserve margin, i.e., the reserve, expressed in Mw, 4th Column, divided by the peak load, expressed in Mw:

PENNSYLVANIA POWER COMPANY

Reserve calculations

Year	Peak Load	Projected	Reserve on Peak		Reserve Margin
		Capability	Mw	% Capability	
1987	* 660	779	119	15.3	18.0
1988	* 667	854	187	21.9	28.0
1989	** 653	808	155	19.2	23.7
1990	** 660	804	144	17.9	21.8
1991	** 667	802	135	16.8	20.2
1992	** 674	799	125	15.6	18.5
1993	653	797	144	18.1	22.1
1994	660	791	131	16.6	19.8

PENNSYLVANIA POWER COMPANY

Reserve calculations

Year	Peak Load	Projected	Reserve on Peak		Reserve Margin
		Capability	Mw	% Capability	
1995	667	787	120	15.2	18.0
1996	674	781	107	13.7	15.9

The OTS objected to reducing Penn Power's net dependable capacity by the PEPCO and Ohio Edison power sales, for the purpose of excess physical capacity calculations. They argued that the power sales are being made at a system average cost while ratepayers [*78] are being asked to pay the high costs associated with Perry 1. By ignoring all sales to the other utilities and accepting Penn Power's load forecast, the OTS concluded that the Company would have 76 Mw of excess physical capacity until 1999.

The ALJ recommended that the Commission adhere to its prior precedent of not including firm capacity (PEPCO sale) contractually committed to another party for purposes of excess capacity considerations. Pa. P.U.C. v. Penn Power, 85 PUR 4th at 403-405.

Therefore, the ALJ concluded that all of Penn Power's capacity is needed to meet the utility's customer demand plus a 34% reasonable reserve margin in 1987 (18% reserve margin) and 1988 (28% reserve margin). The ALJ thus recommended that the Commission find that the Company's addition of Perry 1 to rate base in this proceeding does not result in excess physical capacity.

The OCA filed exceptions to the ALJ's recommendation that adding Perry 1's 63 Mw's to rate base did not result in excess physical capacity. The OCA argued that if the ALJ had properly considered the facts that Penn Power was able to meet its record peak load without interrupting 14 Mw of interruptible load, without utilizing [*79] 24 Mw of reserved plant, and without interrupting 49 Mw of non-firm power sales to other utilities, then he would have found that the Company's reserve margin at the time of its summer peak - without Perry 1 in service - would have been 34.5%. The OCA concluded that Perry 1 was obviously not needed in order for Penn Power to provide reliable service to its customers.

The OTS' exceptions focused on the distinctions between Penn Power's last rate case and the present one regarding the proper effect of the firm off-system sales to PEPCO. OTS argued that the 64 Mw of expensive Perry 1 capacity contrasted unfavorably with the 18 MW of system-wide capacity that was disposed of in the Company's prior rate case. The OTS said that similar Commission treatment will allow the Company to charge ratepayers the high costs associated with nuclear power generation from Perry Unit 1 while simultaneously authorizing the Company to charge the cost of generation of inexpensive system-wide capacity to PEPCO. The OTS stated that Penn Power sells the slice-of-system capacity to PEPCO for approximately \$660/Kw while charging Pennsylvania ratepayers new Perry 1 capacity at about \$4400/Kw.

For these [*80] reasons, the OTS urged the Commission to discount the off-system sales agreements for the excess physical capacity calculations. The OTS calculated that Penn Power's 907 Mw of net dependable capacity together with its projected native load plus a 34% reserve margin results in 76 Mw of excess physical capacity. Therefore, the OTS concluded that all of the capacity represented by Perry Unit 1 constituted excess physical capacity.

The Company's Reply to Exceptions argued that Penn Power's ratepayers have derived substantial benefits in the past due to its conscientious efforts to keep its reserve margin within reasonable bounds, by way of its off-system sales agreements. The Company pointed to its innovative PEPCO Credit Rider as another ratepayer benefit of its off-system sales. The Company further noted that the OTS' Exceptions disregarded 13 Mw of generation unavailability due to seasonal deratings, 21 Mw of BV1 capacity sold to Ohio Edison which ratepayers are not charged for, the costs for 28 Mw of capacity associated with sales to PEPCO which have been removed from rates, and revenue from 49 Mw of capacity sold to GPU and PEPCO which is flowed back to ratepayers through Penn [*81] Power's ECR.

The Company responded to OCA's exceptions by noting that the cold reserve capacity alluded to could not be considered a current source of reliable power. The Company stated that the OCA's witness included interruptible load in his analysis and that proceeds from off-system sales to GPU and PEPCO are passed back to ratepayers as ECR credits.

We conclude that in this case it is proper to include power sales agreements for excess physical capacity determinations due to their benefits to the ratepayers. The Company's calculations indicate a reserve margin of 28% for 1988, which is the year following the test year, and that for the ten-year period 1987 through 1996, the Company projects an average reserve margin of slightly more than 20%.

The method employed by the Company to determine its actual and projected reserve margins is essentially the same as the method employed by the Consumer Advocate and used by the Commission in the last Penn Power rate case where excess capacity was a fully litigated issue. 58 Pa. P.U.C. 305, 60 P.U.R. 593 (1985). For these reasons, we find that 20 percent to 28 percent is an appropriate reserve margin for Penn Power. We, therefore, [*82] conclude that including Penn Power's portion of Perry 1 in rate base will not result in excess physical capacity, as defined in 66 Pa. C.S. § 1323. We, therefore, deny the OCA's and OTS' exceptions on this issue.

3. Excess Economic Capacity

The 63 Mw of Perry 1 sought to be included in rate base by the Company represents baseload nuclear plant. As such, 66 Pa. C.S. § 1323 requires that the Commission make a determination as to whether Perry 1 will produce annual economic benefits which will exceed the total annual costs of Perry 1 during the test year or within a reasonable period following the test year.

The Company contended that Perry 1 will produce net annual economic benefits by 1996. Penn Power's witness compared the costs of Perry 1 to the cost of a hypothetical baseload coal generating plant whose construction did not start until after the completion of Perry 1. We concluded that Perry 1 would have lower total annual costs than the hypothetical new coal plant in 1996. The Company argued that the eight years it took to reach net economic benefits satisfied the "reasonable period following the test year" requirement of Section 1323.

The Office of Consumer Advocate [*83] presented two analyses which concluded that ratepayers would assume huge lifetime losses for Perry 1 and that the plant would never produce any annual economic benefits. First, the OCA witness performed calculations to determine if the cumulative present value of annual economic benefits was positive over the projected lifetime of Perry 1. We found that it was not. Secondly, he compared the cost of a new hypothetical coal baseload plant to Perry 1. He found that Perry 1 would never produce one year of net annual economic benefits to ratepayers over its projected useful life. He stated that even if Perry 1 had a zero capital cost, it would not be economical for Penn Power to own a share of it.

The ALJ was persuaded that the methodology employed by the Company's witness was a more reasoned and appropriate approach in determining excess economic capacity than the assumptions utilized by OCA's witness. The ALJ concluded that waiting until 1996 for Perry 1 to provide a net annual economic benefit (according to the Company's analysis) was a reasonable time "following the test year" for purposes of Section 1323. He reasoned that this was a reasonable period of time due to the uncertainties [*84] inherent in load growth projections and in planning for and constructing baseload capacity. The ALJ cited a previous Commission decision, Pa. P.U.C. v. PECO, 61 Pa. P.U.C. 589 (1986) for the proposition that life cycle analysis of nuclear base load generating plants is irrelevant for purposes of determining excess economic capacity under Section 1323. The ALJ thus recommended that no excess economic capacity adjustment be made in this case.

The OCA excepted to the ALJ's recommended decision. OCA argued that: (1) under either Section 1323 of the Public Utility Code or any rational standard, a plant which produces enormous losses for each of the next eight years and then shows a meager benefit in the ninth (according to the Company's analysis) is not economical; (2) using Penn Power's own analysis, the losses caused by Perry 1 exceed \$45 million per year for the next eight years; (3) at the end of this eight year period, the total losses from Perry 1 exceed \$400 million; and (4) in 1996, under the Company's assumptions, Perry 1 produces economic benefits of less than \$10 million. The OCA also stated that these figures constitute the Company's 'best case' scenario for Perry 1. [*85] OCA asserted that, based on the evidence, the only rational conclusion is that Perry 1 is uneconomical and must not be fully included in rates.

The Company's reply to the OCA's exceptions stated that errors in the OCA's analysis, if corrected, would eliminate over 78% of Perry 1's alleged losses. The Company pointed to theoretical and methodological errors in OCA's analysis which rendered it, in the Company's opinion, of little, if any, probative value. The Company cited Pa. P.U.C. v. PECO, Docket No. R-850152 (Orders entered June 27, 1986 and July 25, 1986) as support for its analysis. Penn Power argued that in the PECO case, supra, the Commission found that eight years was a reasonable period of time to wait for net annual economic benefits. The Company found significant the fact that its witness' analysis demonstrated that Perry 1 would generate net annual economic benefits by 1996, or eight years from now. The Company urged the Commission to adopt the ALJ's recommended decision and refrain from making an excess economic capacity adjustment.

In this regard, we are persuaded by the Company's analysis that Perry 1 will produce annual economic benefits within a reasonable [*86] period following the test year. We, therefore, deny OCA's exception and decline to make any excess capacity adjustment in this case, pertaining to the addition of Penn Power's share of Perry 1 to rate base.

C. Perry I Common Plant

The Company presented a claim for inclusion in rate base of all of its share of the costs of the common facilities associated with Perry 1. This constituted a departure from prior Commission precedent because this Commission has previously authorized rate base inclusion of only one-half of common facilities costs where a dual-unit generating station is being built. A second generating unit, Perry 2, is scheduled to be built at the same location. For this reason, the OCA objected to this claim, and proposed rate base inclusion of only 50% of the costs associated with the common plant, consistent with prior precedent.

The ALJ concluded that since work on Perry 2 had been suspended due to a co-owner's refusal to grant construction authority, it is highly unlikely that the second unit will be built and, therefore, recommended that the OCA's adjustment be denied.

In its exceptions to the ALJ's recommendations, the OCA points out that Penn Power's [*87] own statements entered into the record prove that the co-owner's "decision was independently made and does not represent a decision on the part of the Company [Penn Power] to abandon Unit 2 for rate making or any other purpose." (Emphasis supplied) OCA Ex. p. 12.

The Reply Exceptions filed by the Company argue that Penn Power submitted substantial uncontested evidence which demonstrated that virtually all of the common facilities at issue are currently required for Perry 1's operation.

The Company argues that the co-owner's request for rate base treatment of similar costs was granted by the Commission. Penn Power acknowledges that the co-owner had withdrawn from participation in Perry 2. The OCA points out that until Penn Power formally abandons Perry 2, the non-participating co-owner's share could be sold to another concern and construction commenced.

In this regard, we are of the opinion that consistent with our prior decisions, Penn Power should include only one-half of common plant in rate base until the Company formally withdraws from

the Perry 2 program. We, therefore, grant OCA's exceptions on this issue, and reduce the Company's claimed rate base by \$36,412.

[*88] D. Beaver Valley Common Plant

The Company presented a claim for \$32,120,000 which is the amount associated with Penn Power's portion of Beaver Valley Unit 2 ("BV2").

The Company argued that these common facilities were required in order for BV1 to achieve its planned useful life, and would have been built even if BV2 had never been constructed. This allocable share of common plant was required in order to comply with important safety and regulatory requirements, according to the Company. The ALJ agreed.

The OCA excepted and indicated that the evidence on the record clearly demonstrated that: BV1 has operated at full capacity in compliance with all safety requirements for ten years; the expansion of existing BV1 facilities did not benefit that unit but were caused by BV2 construction; and that if BV2 had not been built then these additional common plant facilities would not have been necessary. Since Penn Power has no ownership interest in BV2, the OCA argues that Penn Power's ratepayers should not pay for these additional common plant costs.

The ALJ was persuaded by the Company's witness that BV1 had initially been constructed with the minimum required amount of supporting [*89] facilities, e.g., radioactive waste storage facilities, auxiliary steam systems, etc. Therefore, the additions to common plant were necessary to extend the operating life of the unit and to increase the safety and efficiency of the unit. We concur and, thus, deny the OCA's exception.

E. Plant Held for Future Use

Various land holdings denominated as being held for future transmission and substation sites were initially claimed by the Company in rate base. The Company deleted this claim for rate base treatment of \$554,540 when the Pennsylvania Supreme Court denied such claims in *Barasch v. PUC, Pa. , 532 A.2d 325 (1987)*.

Until the property is placed in service, Penn Power requested permission to accrue an allowance for funds used during construction (AFUDC) on its investment and to include such capitalized interest charges in rate base at the appropriate time. No party objected and the ALJ recommended approval of it as a reasonable request. No exceptions were filed with regard to this methodology. We concur and adopt the ALJ's recommended decision as our own.

F. Depreciation

The Penn Power claim for accrued depreciation reflected an operating life extension of [*90] six years of BV1. This depreciation reserve reflects the elimination of the West Lorain peaking facilities from rate base. The claim was supported with detailed calculations and a complete description of the depreciation methodology employed. No objections were made and the ALJ recommended that the Company's rate base claim for accrued depreciation be accepted as filed. No party filed exceptions to the claim. We concur with the reasonableness of the Company's claim and therefore adopt the ALJ's decision.

G. Pollution Control CWIP

The Company requested rate base treatment for two construction projects involving the installation of pollution control facilities at the Bruce Mansfield coal-fired power plant. No party objected and the ALJ recommended granting Penn Power's request.

No party filed exceptions to this recommendation. We agree with the ALJ's recommendation and adopt his decision as our own.

H. Working Capital

1. Coal Inventory

The Company claimed an amount reflecting a 60 day supply of coal valued at an average projected inventory price at each of three coal-burning facilities. The Pennsylvania retail portion is \$7,054,329.

The OCA recommended adjusting [*91] the average cost of coal inventory to reflect recent prices which are considerably lower than the Company's projected prices.

The OTS recommended reducing the amount of coal inventory to a 50-day supply and also revaluing the stock to represent lower current coal prices.

In rebuttal, the Company claimed an additional \$.84 per ton which was to be added to the price of Mansfield coal in order to recoup unrecovered handling charges.

Prior Commission procedure with regard to this issue is reported at Pa. P.U.C. v. Penn Power, 85 PUR 4th 356, wherein the Commission adopted a 60 day supply of coal as a reasonable amount for the Company but adjusted the price as well. The ALJ was persuaded by the Company that a 60 day supply of coal was reasonable as it was developed by a review of actual inventory levels which are, in fact, greater than 60 days. The ALJ adopted the price adjustment sponsored by OTS/OCA to reflect current coal prices but agreed with the Company's handling charges for Mansfield coal.

The OTS excepted to the ALJ's recommendation and stated that the Company's inventory level for ratemaking purposes should be reduced from 60 to 50 days due to enhanced system flexibility [*92] and reliability caused by the addition of a new nuclear power plant, Perry Unit 1.

We concur with the ALJ that prior precedent and the Company's higher than claimed actual inventory levels are persuasive in adopting the Company's claim for a 60 day supply of coal.

We also agree with the ALJ's price adjustment, and adopt his decision as our own. We, therefore, deny the OTS' exception.

2. Cash Working Capital

The Company did not claim any rate base amount for cash working capital ("CWC"). In response to our suspension Order, however, the Company filed an updated lead/lag study as well as

preferred stock dividend and long term debt interest calculations. As these calculations did not demonstrate a CWC need, the Company chose not to make a claim.

The OTS and the OCA presented calculations which supported a negative CWC adjustment. The ALJ was unpersuaded, and recommended rejecting these negative CWC adjustments to rate base. The ALJ further recommended deleting the CWC issue in future rate proceedings.

Both the OTS and the OCA excepted to the ALJ's recommendation and argue that ratepayers supplied capital should be deducted from rate base. The Company excepted, opposing [*93] the ALJ's recommendation of deleting the CWC allowance in future proceedings.

We agree with the ALJ that no rational basis exists for a negative CWC allowance as the Company did not propose any CWC adjustment. We, therefore, deny all exceptions and adopt the ALJ's decision as our own.

I. Miscellaneous Adjustments

Several tax related issues discussed in the section on taxes have rate base implications. These implications are stated herein for convenience sake. For rate base purposes, we concur with the ALJ's recommendation of reducing the Company's claimed rate base in the amount of \$3,552,264 to reflect the adjustment for deferred tax balances. We agree with the ALJ that no adjustment to the Company's claim is appropriate in this case pertaining to either contributions in aid of construction or the alternate minimum tax.

J. Rate Base Conclusion

As a result of our foregoing adjustments to the Company's rate base claims, the net jurisdictional rate base allowance approved herein for Penn Power is \$653,995,000.

V. REVENUES AND EXPENSES

A. Operating Revenues

Penn Power's revised showing regarding its jurisdictional operating revenues under present rates, for [*94] the future test year is \$176,046,055.00 (PP St. 1-R, Schedule 7, p. 2). The development of the revenue forecast and the Company's budgeting process is described in PP St. 1, pp. 7-9. In accord with Commission practice, the estimated future test year revenues were adjusted to eliminate revenues collected through the Company's energy cost rate (ECR) and through the State Tax Adjustment Surcharge (STAS) (PP Ex. 1 Future, p. J5).

Additional adjustments were made: (1) to reflect the rate reduction ordered in the last case (PP St. 1, p. 10); (2) to reflect changes in the number of customers and usage patterns (PP St. 1, p. 11); (3) to eliminate revenues from off-system sales to non-affiliated utilities (PP St. 1, p. 11); and (4) to reflect rental income derived from sales of capacity to Ohio Edison (PP St. 2, p. 4).

The OCA proposed two adjustments to the pro forma future test year jurisdictional operating revenues claimed. The OCA witness, Mr. Knudsen, explained that: the CAPCO companies own jointly (but operate individually) a number of generating stations. Each operating company pays its own expenses and is reimbursed after the fact by other owners. The compensation is

based [*95] on an estimated cost of capital. In the case of Penn Power, as a net provider of capacity, it receives compensation at a rate of return level higher than its cost of capital. Mr. Knudsen was of the opinion that these revenues constitute a windfall arising from "utility operations" and, as such, should belong to ratepayers. The amount at issue is \$165,000.00 (OCA St. 3, pp. 21-22, Ex. TEK-9.)

In response, the Company stated that carrying charges billed by Penn Power to other CAPCO owners, do not arise from the sale of energy from any facilities which the Company owns, or that its ratepayers support in any way. Moreover, that portion of the Mansfield Plant for which the billings are made is owned entirely by the remaining four CAPCO companies and Penn Power has not made rate base claims, operating expense claims, or requested working capital allowances in connection with these facilities. Indeed, continued the Company, only the Company's 5.76% share of the Mansfield Plant and related expenses have been claimed in this proceeding. Since ratepayers have not been assessed the costs or billings which give rise to the carrying charges, no portion of the carrying charges received by [*96] Penn Power should be included in ratemaking revenues (PP St. 3-R, pp. 1-2). The Company also argued that this OCA proposed adjustment is inconsistent with the Commission's treatment of the revenues and expenses of the PEPCO sale, addressed in the section of this Opinion and Order dealing with Excess Capacity (Tr. 810-813).

The ALJ recommended that we reject this OCA - proposed adjustment. He stated that he agreed with the Company that the transaction in question was totally outside of the scope of the present rate proceeding. In the past, continued the ALJ, the Company accounted for the revenues in question under "Rent From Electric Property" and claimed carrying charges in expenses (payments to Duquesne and Ohio Edison) in working capital. In its last two cases, the Company has changed the treatment of this item to that used here, i.e., no revenues or expenses claimed (PP St. 3, pp. 2-3).

No party excepted to the ALJ's recommendation on this matter.

We agree with the ALJ's recommendation and hereby adopt it. As explained by the ALJ, this transaction is outside the scope of this proceeding.

The OCA also proposed a revenue adjustment to reflect a change in the late payment [*97] charge for commercial and industrial customers and an adjustment for historic forfeited discounts (OCA St. 3, pp. 26-27)

As to the first adjustment, the Company concurred only if the Commission approves the requested tariff change. The change would increase the late payment monthly percentage charge from 1.35% to 2%. The ALJ recommended approval of this change in the Rate Structure section of his Recommended Decision.

We adopt this OCA proposed adjustment and, thereby, increase pro forma revenues by \$120,316 (OCA St. 3, p. 27).

As to the proposed adjustment for historic forfeited discounts, the Company's rebuttal testimony established that the data relied on by the OCA contained an unusually high level of forfeited

discounts, and that the level the Company claimed was a more accurate projection of the level likely to be experienced (PP St. 1-R, pp. 5-6).

The ALJ recommended that this OCA proposed adjustment, which would increase pro forma revenues by about \$80,000, be rejected.

The OCA excepted to this recommendation of the ALJ (OCA Exceptions, pp. 20-22). Specifically, the OCA took issue with the ALJ's statement that the Company's claimed level for this item is a more [*98] accurate projection of the level likely to be experienced. The OCA stated that the six months of data referenced in the Company's rebuttal testimony does not and cannot establish that the data relied on by the OCA is unreliable, because that six-month period ended October 1987 and does not include the winter months, when substantial increases in forfeited discounts occur. It is undisputed that the level of forfeited discounts projected by the Company is substantially lower than the Company's actual experience.

In response, the Company stated (Company Reply Exceptions, pp 13-14) that we should adopt the ALJ's recommendation on this issue, since the historic test year data used as the basis for the OCA's adjustment is abnormally high and is, therefore, not reflective of normal conditions. The OCA's reliance on only two months of data from the historic test year (i.e., October and January) as the basis for its argument incorrectly measures the impact of the winter season and fails to reflect other offsetting factors.

Based upon our review of the record as to this matter, we find that we agree with the recommendation of the ALJ and we, therefore, reject the OCA's proposal. As [*99] concluded by the ALJ, the Company's claimed level for forfeited discounts appears to be a more accurate projection of the level likely to be experienced.

In sum, we agree with the recommendations of the ALJ on the issues associated with revenues. We, therefore, accept Penn Power's claimed pro forma jurisdictional revenues at present rates, except for an adjustment to reflect a change in the late payment charge for commercial and industrial customers and an adjustment of \$3,273,000 to reflect credits for capacity sales that will be credited to the Company's Energy Cost Rate instead of base rates.

B. EXPENSES

The Company's revised claim for operation and maintenance expenses totals \$111,169,955.00 (PP Ex. 1 Future, J. Z. Revised, Schedule 7, p. 3).

1. Employment Expenses

(a) Employee Wage Increase

The Company's future test year claim included provisions for a 3.75% pay increase for unionized employees, 4.75% increase for non-union members, and associated benefits, calculated on the basis of a level of employment projected for the end of the future test year (PP St. 2, pp. 5-6; PP Ex. 1 Future, pp. J8 - J10.)

Both the OTS and the OCA proposed to adjust this item of expense [*100] to reflect pay raises for both union and non-union employees of no more than 3.75%, and also to make the appropriate downward adjustments to benefits.

The OCA argued that the management pay increase, a projected average percentage, should be rejected under the Commission's practice of "denying excessive, non-negotiated, discretionary increases" (OCA Main Brief, p. V-22).

The OTS contended that labor management negotiations are conducted at arms' length and are reliable for accurately reflecting changes in productivity, economic conditions, and cost-of-living. The OTS argued further that the Company presented no evidence that its non-union employees have been significantly more productive or more adversely affected by the economic conditions than its union employees (OTS Main Brief, p. 28).

Responding to the arguments of the OCA and the OTS, the Company stated that a non-union employee starts at about 80% of the standard rate for a specific job while a union employee starts at 82% to 90% of the standard rate or maximum. Unionized employees may receive increases every six months and generally reach the standard rate in 18 to 30 months. Non-union employees may receive increases [*101] only on an annual basis and take longer to reach the standard rate. The Company further contended it is treating both classes of employees the same; the difference in percentages is accounted for by timing differences (PP ST. 2-R, pp. 15-17). In its Main Brief, the Company pointed out that the 4.75% increase is at the lower end of the inflation rates projected for 1988 by the rate of return witness for OTS (PP Main Brief, pp. 166-167).

The ALJ recommended that we reject the proposed OCA and OTS adjustments to wage and benefit expenses. The ALJ made this recommendation because he had concluded that the Company had met its burden of proof, and that it had adequately demonstrated that it is treating its union and non-union employees in an equal fashion. In addition, stated the ALJ, this Commission has not established an inflexible rule with regard to tying wage benefits to negotiated contracts. Finally, stated the ALJ, it was difficult for him to accept the characterization of a 1% differential as excessive.

The OCA excepted to the ALJ's recommendation on this issue (OCA Ex. pp. 22-24). The OCA stated that, on this issue, the ALJ had accepted the Company's assertion that its [*102] wage and salary employees are treated differently. The OCA contended that the argument that there is a difference between merit and wage increases has been rejected by Commission numerous times. In the absence of a showing of unique factors or increased productivity, the OCA urges the Commission to follow the practice of using the negotiated union wage increase as a benchmark for salary increases for non-unionized employees. The OCA further stated that there are two reasons supporting the usual Commission practice: (1) union wages are the result of arms-length collective bargaining and are therefore, presumptively, reasonable, and (2) there is no contractual obligation associated with non-unionized employees, so utilities have more control over this expense. The claimed salary expense should, therefore, be reduced by \$359,000.

The OTS also excepted to the ALJ's proposed resolution of this issue (OTS Ex. pp. 15-17). It is the contention of the OTS that the Company failed to meet its burden of proof as to this matter,

having presented no credible evidence that its non-union employees were more productive or more adversely affected by cost of living increases than its union [*103] employees. In contrast to the testimony of the Company witness, union and non-union employees are not being treated equally. The OTS also contests the ALJ's position that a 1% differential is de minimis. The OTS states that the burden of proof to justify expenses is on the Company, and, in this instance, the Company has not justified the expense. Finally, stated the OTS, the Commission considered this same issue in Penn Power's last rate case (at R-850267), and found that, for ratemaking purposes, the level of salary increases for non-union employees should be limited to 3.75%.

The Company responded in its Reply Exceptions (pp. 14-16), stating that the holdings on this issue in the Company's prior rate cases should not be viewed as a "hard and fast" rule, but as based on the specific facts and circumstances presented. The evidence submitted in this case, it is argued, is substantially more compelling than in prior cases, the Company having made an effort to submit a much more detailed and comprehensive description of its salary structure for union and non-union employees than was presented in the last rate proceeding.

On review of the arguments of the parties in their Exceptions [*104] and Reply Exceptions on this issue, we agree with the resolution proposed by the ALJ, and we, therefore, reject the OTS and OCA proposed adjustments for this item. We agree with the ALJ that the Company has demonstrated that it is treating its union and non-union employees in an equal fashion. As pointed out by both the ALJ and the Company, prior determinations on this issue, were limited to the specific facts of those proceedings. Finally, the 4.75% figure is actually at the lower end of the range of inflation projected by the OTS' own rate of return witness for 1988. The fact that the Company's claim is not based on a negotiated agreement is irrelevant and only means that it is similar to any other future test year cost estimate which is not based upon a contract.

(b) Employee Level Adjustment

The OCA asserted that the wage expense claim should be adjusted to reflect a lower level of employees (OCA St. 3, pp. 30-31).

The Company responded that the OCA improperly included temporary and part-time employees in its calculation, who have been excluded from the Company's wage annualization calculation. The number of employees projected for the end of the future test year is [*105] 1,739; the wage annualization was computed on an employment level of 1,740 (PP St. 2-R, p. 18).

The Company used the figure 1,771 as its employee level as the basis for its wage expense claim. For the purpose of annualizing the projected wage increase, the Company used a figure of 1,740 employees (Tr. 120). The figure 1,771 includes the Company's temporary and part-time employees.

The ALJ rejected the OCA proposed adjustment on this item. The ALJ added, however, that the parties should clarify for the Commission just how this claim was calculated, with references to the record. The ALJ further stated that, in the event the Commission concludes that the OCA is correct that the number 1,771 was used to calculate the wage expense claim, then it is recommended that the OCA adjustment be adopted.

The Company responded to this issue in its Exceptions (pp. 11-13). There, the Company stated that the OCA proposed adjustment would have eliminated the annualized labor costs associated with 19 employees, which represent the difference between the average number of employees of 1,771 budgeted during the future test year and the 1,752 employees anticipated at the end of that period (OCA [*106] St. 3, pp. 30-31).

The Company then explained its position; its labor expense claim is in fact based on the 1,771 average number of employees budgeted during the future test year period (PP Ex. II-D-10(a)). That figure includes 1,746 full-time employees and 25 part-time and temporary employees (PP St. 2-R, p. 18). The 1,752 figure anticipated at the end of the future test year consists of 1,739 full-time employees and 13 part-time and temporary employees (PP Ex. II-D-10(a); PP St. 2-4, p. 18). In annualizing for actual and anticipated wage increases, the Company utilized a figure of 1,740 employees, which represents the estimated number of full-time employees at the time of each increase (PP Ex. 1 Future, p. J8). The Company continued, stating that, the fact that there is a 19 employee variance between the test year average and test year end figures does not indicate that the OCA's proposed adjustment is appropriate. In sum, merely because there is projected to be a reduction of 7 full-time employees by the end of the future test year (i.e. 1,746 less 1,739) does not indicate a permanent condition. Because of the variability in the number of full-time, part-time, and temporary [*107] employees during each year, it is more appropriate to utilize an average rather than a year-end level of employees for ratemaking purposes.

In its Exceptions (pp. 22-24), the OCA stated that the ALJ had erred in refusing to recognize as the basis of the wage expense claim the lower employee level projected by the Company to be in place at the end of the future test year. The OCA further stated that the ALJ had recommended rejection of this adjustment because he had misunderstood the nature of the Company's claim. The Company's wage expense claim - not the wage increase claim - is based on the figure of 1,771, the average test year number of employees. The OCA urges that its proposed adjustment to reduce the Company's wage claim by \$286,047 should, therefore, be adopted.

Again in its Reply Exceptions (pp. 10-11), the OCA stated that the arguments made by the Company in its Exceptions on this issue are irrelevant, and cannot be used to support the Company position. The Company has been reducing its work force over the last several years. The wage claim is based on the figure 1,771, the average number of employees during the future test year. Its wage increase annualization [*108] is based on the figure 1,740, the number of full-time permanent workers. Because of the downward trend in the number of employees, the OCA recommends that the future test year end level of employment be used to calculate the wage allowance.

On consideration of the arguments of the parties on this issue, we reject the OCA proposal of a \$286,047 adjustment. We reach this decision because we find, as stated by the Company, that the OCA proposed adjustment would eliminate the annualized labor costs associated with 19 employees. These 19 employees represent the difference between the average number of employees (1,771) budgeted during the future test year, and the 1,752 employees anticipated at the end of that period. The Company has adequately explained its position. Because of the variability in the number of full-time, part-time, and temporary employees during each year, it is

more appropriate to utilize an average rather than a year-end level of employees for ratemaking purposes.

2. Perry I O&M Expenses

Both the OTS and the OCA proposed adjustments to the Company's estimated O&M expenses for Perry 1. The Company had claimed \$8,458,397 for this item, a figure developed from [*109] an estimate provided by Cleveland Electric Illuminating Co. (PP St. 1, pp. 13-14; Ex. 1 Figure, p. J13 (Adjustment 23P)).

The OTS proposed a deduction of \$2,202,000 from the amount that had been claimed. OTS witness L. B. Jones developed two comparison groups of nuclear power plants. The first group was comprised of units located in Pennsylvania, the second group consisted of utilities outside Pennsylvania that have Boiling Water Reactors (BWR) as does Perry. Mr. Jones then developed a cost per Mw and a cost per kilowatt hour for Perry 1 and each barometer group (OTS St. 3, pp. 2-6; Ex. 3, Schedules 1-3).

The Company offered rebuttal in the form of an analysis limited to single BWR's placed in service after the incident at TMI. The result showed an average cost per Mw higher than the amount claimed for Perry 1 (PP St. 1-4, pp. 7-8, Schedule 3).

The ALJ recommended that we reject this proposed OTS adjustment. He made this recommendation on several bases. He noted that OTS had not directly attacked the preparation of the Company estimates. He also noted that ALJ Meehan had considered and rejected a very similar adjustment in the recent Duquesne case, slip op. p. 318. [*110] He noted, finally, that the Pennsylvania data does not necessarily match in two areas, time periods and expenses associated with outages. Both factors could greatly vary the outcome of the analysis (PP St. 1-4, p. 8; Schedule 3).

The ALJ also recommended that we reject the OCA recommendation on this issue. The ALJ stated that, like the OTS, the OCA had not directly attacked the CEI prepared estimate (OCA St. 3, p. 36; OCA St. 2, Ex. RAR-15, Sheet 16 (Table 7)). The ALJ also stated that he believed the OCA analysis was flawed in the same way as the analysis by the OTS, i.e., a lack of comparability.

The OTS excepted to the ALJ's recommendation on this issue, and again proposed that we act to reduce the Company's claimed expenses for this item by \$2,202,000 (OTS Ex., pp. 18-20). The OTS went on to state that the burden of proof is on the Company to justify its expenses, and that the Company has not in this case met its burden to show that the two groups of data presented do not match. Therefore, the OTS urges that the ALJ's recommendation be rejected.

The OCA, although it had originally proposed an adjustment to this item, did not file an exception to the ALJ's recommendation. [*111]

In its Reply to Exceptions, the Company proposed that we reject the OTS argument that the nuclear units in OTS witness Jones' comparison groups are comparable to Perry 1. (Company R. Ex. pp. 16-17)

We agree with the ALJ on this issue and, therefore, we deny the OTS exception. As stated in the Company's Reply to Exceptions, a review of OTS witness Jones' comparisons shows that the data for his Pennsylvania group is not reliable and would probably understate the level of costs likely to be incurred at Perry I. Also, the Company presented a comparison of its own, and this comparison demonstrated that the Company's claim was less than the level of costs experienced at other units. Finally, we rejected an identical OTS adjustment in our recent Duquesne rate proceeding. The rejected adjustment was based on the same type of evidence as presented in this case. With regard to the issue of outage costs as a factor contributing to the lack of comparable data, the OTS was incorrect in its assertion that outage costs should be removed entirely from the analysis.

3. Uncollectible Accounts Expense

In addition to its normal claim for uncollectible account expense, the Company sought [*112] recovery of an amount to reflect a portion of the unpaid balance owed by Sharon Steel, prior to the filing of its current bankruptcy petition. Both the Company and the OCA asserted that the amount claimed for Sharon Steel was \$600,000; the OTS asserted that the amount was \$420,834, as set forth at PP Vol II, Section II-D-1, p. 4, Main Briefs of the Parties.

Both the OTS and the OCA proposed that the write-off for Sharon Steel be denied as speculative. The Company argued in response that its estimated amount was provided as a reasonable estimate of the amount owed which will not be recovered. Should its proposal not be accepted, the Company requested in the alternative that the amount be amortized over four years (PP St. 2-4, pp. 12-14).

The ALJ recommended that we deny this claim, and delete \$600,000 as an allowable expense. He based this recommendation on several factors. First, he stated that he could not find any clear statement of the total amount owed by Sharon Steel. The claim was not for a normal ongoing expense but it is for an amount fixed by the filing of a bankruptcy petition. The ALJ stated that he agreed with the OCA and the OTS that the claim is speculative. [*113]

In addition to the above contentions, the OCA also proposed that the Company eliminate its uncollectible account reserve over four years and, in the future, present its rate case claim on the same basis as it will be filing its federal income tax return; i.e., conform the rate case claim to actual write-offs. In view of the difficulty of presenting actual costs in the context of projecting a future test year, the OCA urged the adoption of a normalized level for uncollectibles.

In response, the Company stated that it adhered to Federal Energy Regulatory Commission directives to use accrual accounting, and that the use of a reserve is appropriate under these principles (PP St. 2R, pp. 14-15).

The ALJ recommended that we reject this second OCA adjustment. He stated in support of this recommendation that the Company's tax witness made it clear that timing differences have always occurred between uncollectibles claimed for rate making purposes (projected) and actual write-offs. While the Tax Reform Act of 1986 required the latter, it did not require the discontinuance of the use of the reserve for book and rate making purposes (PP St. 5R, p. 13).

The Company excepted to the [*114] ALJ's recommendation that \$600,000 be eliminated as an allowable expense (Company Ex., p. 13). The Company's position was that the ALJ recommendation was based on our disallowance of a similar item in Pa. P.U.C. v. Duquesne Light Co., Docket No. R-860378 (March 10, 1987), (R.D., pp. 148-149). The Company referred to the arguments set forth in its Initial Brief (pp. 181-183) and stated that the situation presented in the Duquesne case was distinguishable. The Company further stated that, at a minimum, a four-year amortization of these costs, with appropriate provision for refund, should be allowed.

The OCA also excepted to the ALJ's recommendation on the second component of this issue (OCA Ex. pp. 24-26). The OCA stated that the ALJ had based his recommendation on a misunderstanding of the OCA's position, and, further, that his recommendation was not supported by the record in that the Company was unable to show why it continued to need a reserve for uncollectible accounts in addition to its normalized on-going expense allowance.

The Company replied to the assertions of the OCA in its Reply to Exceptions (Company R. Ex. pp. 18-19). The Company gave several reasons why we should [*115] deny OCA's recommendation on this issue. First, stated the Company, it is irrelevant from a ratemaking standpoint that Philadelphia Electric Company does not employ a reserve and that Penn Power is eliminating the reserve for tax purposes. Second, it is necessary that such a reserve be maintained. Third, the fact that the reserve may contain certain costs which will not be written off until after the future test year is irrelevant, since the reserve itself is not reflected in rates.

The OCA filed Reply Exceptions, in which it stated that, since the Company presented no argument not considered by the ALJ, or any error contained in the Recommended Decision, we should adopt the ALJ's recommendation (OCA R. Ex., pp. 11-12). The Company has argued that the issue is distinguishable from that in Pa. PUC v. Duquesne Light Company, Docket No. R-860378 (Order entered March 10, 1987), in which we disallowed a similar claim associated with the LTV bankruptcy. The OCA again presented its argument that there is no meaningful distinction in the fact that Duquesne included the entire receivable in its claim, while Penn Power is claiming a 75% write-off. The amount of this write-off, if any [*116] should occur, simply is unknown and unknowable at this point in time.

After consideration of the positions of all the parties on this issue, we agree with the resolution proposed by the ALJ. We, therefore, deny the Company's claim for \$600,000 for this item. As explained by the ALJ, this claim is speculative in nature. We also agree with the ALJ with regard to his recommendation concerning the second OCA proposal, i.e., that the Company eliminate its uncollectible account reserve over four years. We find that the OCA has not presented a compelling argument as to why the Company should be required to do this. As stated by the Company, the use of this reserve is appropriate under the principles of the appropriate accrual accounting methods. We, therefore, deny the OCA proposal with regard to the elimination of Penn Power's accumulated uncollectible reserve. Accordingly, we deny the Company's and the OCA's Exceptions.

4. EEI Dues and Media Communications Expense

The Company claimed the amount of \$40,445 for the Edison Electric Institute's Media Communication program and the amount of \$58,872 for EEI membership dues. The claim for the Media Communication program is found [*117] in PP Vol. II, Schedule II-D-7(b).

The OTS proposed to disallow 25% of the dues claimed and all of the Media Communication claim on the basis of a preliminary report of the National Association of Regulatory Commissioners dated October 12, 1983 (OTS ST. 6, p. 3; Ex 6, Sch. 5). The OCA also proposed disallowance of the Media Communication claim based on our past decisions (OCA St. 3, p. 45.)

The ALJ recommended that both the OTS and the OCA adjustments be adopted, which would result in two expense disallowances of about \$15,000 and \$40,000 for a total of \$55,000 (\$51,000 on a Pennsylvania jurisdictional basis). The ALJ made this recommendation because, he stated, the Company had cited the appropriate statutory authority in its Main Brief, pp. 190-193, but had failed to present any testimony to demonstrate compliance with the statutory requirements.

No party excepted to this recommendation.

On review, we adopt the ALJ recommendation on this issue since, as he noted, the Company failed to present any testimony to show compliance with statutory requirements. We, therefore, adopt an expense disallowance of \$51,000 for these two items.

5. Injuries and Damages Expense

The OCA [*118] proposed two adjustments to the Company's claimed injuries and damages expenses, the first a downward adjustment of \$82,000 for this item to an "actual" anticipated level, and also a reduction to the reserve amount (OCA St. 3).

The Company responded to the first OCA contention, i.e., that the claimed level for this expense does not accurately reflect the level expected to be incurred. The Company witness, Mr. Pappas, stated that the Company's claim for this item (budgeted accrual to the injuries and damages reserve) is not related to the level of settlement payments anticipated during the future test year. Instead, it represents the anticipated level of claims and, under accrual accounting principles, is properly reflected as a current expense. The discrepancy between the Company's claim and the anticipated level of settlement payments is attributable to a time difference. A comparison of settlement payments with the corresponding accruals for claims during the period June 1984 to August 1987 reveals that the accruals were actually less than the amounts for which the Company eventually settled the claims.

The OCA further proposed that the Company either eliminate entirely [*119] or drastically reduce the injuries and damages reserve. The OCA suggested that the Company should abandon the concept of accrual accounting and adopt a cash accounting methodology. In response, the Company stated that FERC mandates that a utility keep its accounts on the accrual basis (which requires all known transactions of appreciable amounts to be recognized currently). The Company projects that it will incur \$347,000 in additional claims for injuries and damages in the future test year. Under GAAP, this is the amount which should be reflected as an expense and a

liability on the Company's books. The reserve for injuries and damages does not represent solely ratepayer-supplied funds.

The ALJ recommended that we deny both of these OCA proposed adjustments. He stated as his rationale that the Company had demonstrated the reasonableness of its claim and the methodology behind it. In addition, the Commission rejected a somewhat similar OCA-proposed adjustment in the Company's last rate case.

In its Exceptions, the OCA repeated its arguments that these two adjustments are reasonable and should be adopted (OCA Ex., pp. 26-28). The OCA had recommended that the injuries and [*120] damages accrual be set at a reasonable level based on the payouts projected by the Company, and second, that the accumulated reserve of \$2.4 million be reduced to \$1.0 million over a three-year period (OCA Main Brief at V-34 to 39, Reply Brief at 56-59). The OCA also stated that its proposal should not be rejected merely due to its decision not to file surrebuttal testimony on this issue, arguing that the adjustments proposed are reasonable, the Company's claim for this item is overstated and the reserve is excessive. The OCA also states that the points raised by Company witness Pappas in his rebuttal testimony were addressed completely by the OCA in its briefs, as noted above.

In its Reply to Exceptions, the Company again stated that a review of recent accruals and corresponding settlement payments reveals that the Company actually pays more than it accrues (Company R. Ex. 1, p. 18).

On review of the positions of the parties, we agree with the recommendation of the ALJ. As stated by the Company, (supra) a review of recent accruals and settlement payments reveals that the Company has actually paid more than it has accrued. With respect to its proposed reduction to the reserve, [*121] the OCA ignored the fact that such an adjustment would represent a departure from generally accepted accounting principles and would improperly shift current expenses to future generations of ratepayers. In addition, the OCA failed to recognize that the reserve did not represent the accumulation of overcollections from ratepayers in prior years. We, therefore, reject the OCA proposal with regard to these two items. Accordingly, the exception of the OCA is denied.

6. MAS Task Force

A joint Ohio Edison/Penn/Power Management Accounting Systems Task Force (MAS) is developing an automation system for the Company's general ledger system (accounting) and budgeting process (Tr. 164, 1186-1186). For this item, the Company presented an expense claim of \$241,879 (PP Vol. II, Schedule II-D-7(a)).

The OCA's position on this item was that developmental costs should be capitalized and deferred until the new system is operational or put aside (OCA St. 3, pp. 40-41).

Company witness Mr. Pappas stated that the Company's decision to expense this amount was based on Financial Accounting Standards No. 86, which he furnished (PP 2R, p. 20). He contended that the Company was not covered by [*122] the financial disclosure provisions of FAS No. 86 (Tr. 1188).

The ALJ recommended that we reject this adjustment. He based this recommendation on the fact that the OCA had agreed with the nature of this expenditure, and on his opinion that the Company had shown that its accounting position was justified. The ALJ also stated that the language at p. 13 of FAS No. 86 (under the heading "Scope") supports the Company's position on the proper accounting treatment for these expenditures (PP St. 2-R, Schedule BLP-2R-6, p. 13).

The OCA excepted to this recommendation of the ALJ (OCA Ex., pp. 28-29). The OCA's argument was that reference to the transcript as cited by the ALJ makes it clear that even the Company's own witness believed that the accounting standard at issue here is not applicable. In addition, argued the OCA, the Company did not present any testimony as to the standard accounting treatment utilized in the case of computer programs developed for internal use. Even on its face, concluded the OCA, SFAS 86 (entitled "Accounting for the Costs of Softwares to be Sold, Leased, or Otherwise Marketed") does not apply to the program at issue here.

In response, the Company stated [*123] in its Reply Exceptions (p. 19) that a close review of Mr. Pappas' cross-examination reveals that he stated only that the notice requirements imposed by SFAS No. 86 are inapplicable. The Company further stated that, as explained in the Company's Initial Brief, the accounting requirements of SFAS No. 86 do apply to the Company's claim.

On review of the arguments associated with this issue, we find ourselves in agreement with the course proposed by the ALJ. We reach this decision because we agree with the Company's interpretation of Mr. Pappas' testimony, i.e., that it is the notice requirements imposed by SFAS No. 86 that are inapplicable to the program at issue here. We, therefore, deny the OCA's exception on this issue and adopt the ALJ's recommendation.

7. Rate Case Expense

The Company initially claimed a rate case expense of nearly \$1.3 million (PP Vol. II, Scheudle II-D-6). This claim has been revised downward to a normalized level of \$800,000 (PP St. 1-R, pp. 6, 19; Schedule 7, p. 3 (J2 Revised)).

The OCA proposed a further downward revision to a normalized level of \$500,000. This adjustment assumes no new rate filing for four years, and that the expenses for the [*124] present case will be substantially less than last year's case (OCA St. 3, pp. 34-35).

The Company agreed that current expenses are less, and that they have been recognized in its revised claim. However, the Company also represented that it will expend at least \$800,000 in the present case (PP St. 1R, p. 6). The Company also pointed out that its projection of no new case for four years assumes approval of its requested increase.

The ALJ recommended that we accept the OCA adjustment and reduce the Company's claimed rate case expense by an additional \$300,000. He made this recommendation in view of the allowable revenue level proposed in his Recommended Decision and in view of his recommendation regarding phase-in. He concluded from these considerations that the OCA proposal was reasonable and would result in a normalized allowance permitting recovery of the Company's costs.

No party excepted to the ALJ's recommendation on this item.

We find the ALJ's recommendation on this item to be reasonable; therefore, we reduce the Company's claimed rate case expense by an additional \$300,000. As concluded by the ALJ, the OCA's proposal is reasonable and results in a normalized allowance [*125] permitting recovery of the Company's costs for this item.

C. Perry I Early Window Costs

The Company claimed an amount of nearly \$6 million as an allowance to "permit synchronization of the commercial operation and rate recognition of Perry I." The amount claimed is one-fourth of a total of nearly \$24 million in claimed costs to be amortized over four years (PP St. 2-R, p. 19, PP Ex. 1 Future, p. J17).

The OCA opposed this claim on several bases. One basis was that the Commission has directed that the claimed costs are not to be recovered in the present case (Order adopted January 15, 1988, at P-870238).

The ALJ stated that, consistent with the Commission's Order at P-870238, the Company's claim for one-fourth of the total deferral of \$22,328,048 (or \$5,179,549 on a jurisdictional basis, PP St. 2R, p. 19) would be removed from consideration in his Recommended Decision. The ALJ added that the Company would be free to urge the Commission to reconsider the Order at P-870238 in its Exceptions. The ALJ also added that he expressed no opinion on the propriety of the Company's eventual recovery of all or part of this item of expense. The ALJ referred to ALJ Meehan's recommendation [*126] in the recent Duquesne rate case; ALJ Meehan concluded therein that the claimed costs should be removed and that he would express no opinion on the issues presented. *Pa. PUC v. Duquesne Light Co.*, R-870651, Recommended Decision dated January 26, 1988, slip. op. 22-29.

In its Exceptions (pp. 13-14), the Company objected to the ALJ's recommendation with regard to this issue. The Company again argued that the recovery of these costs is reasonable, and that it is appropriate to adjudicate this matter in this proceeding. It is inequitable, contends the Company, to reject its claim because it is premature and then to deny recovery at the first opportunity that these costs can be claimed because such recovery would constitute retroactive ratemaking.

In its Reply Exceptions (p. 2), the OTS stated that it supported the recommendation of the ALJ with regard to the amortization of deferred Perry I synchronization cost. The OTS also stated that the Company is here again raising an issue the Commission has already decided. The Commission in its November 5, 1987 Order, as well as its January 21, 1988 Order, specifically stated that any claims for the deferred costs of Perry I will be determined [*127] by the Commission in a subsequent proceeding.

The OCA also responded to the Company's Exceptions in its Reply Exceptions (pp. 12-15). The OCA argued that the Company had already had a chance to request the Commission to reconsider its decision on this issue, and that the Commission had refused this request. It also proved that it is improper for a party to seek reconsideration of a Commission Order by means of a collateral attack.

On review of this issue, we agree with the ALJ's recommendation and we shall not consider this item, consistent with our Order at P-870238. Also as noted by OCA, the issue of the recovery of Duquesne's share of the Perry I and Beaver Valley II early window expenses was also deferred until a subsequent proceeding. Pa. PUC v. Duquesne Light Company, Docket No. R-870651, Order entered March 25, 1988, at 15. Accordingly, we deny the Company's exception.

D. CAPCO Cancellation Costs

In its filing, the Company claimed an annual allowance of \$1,495,215 for a ten year amortization of investments in cancelled CAPCO nuclear plants. No return on the investment was sought (PP St. 1, p. 14, Ex. 1 Future, pp. J2-J3).

The ALJ recommended that this item [*128] be rejected. He made this recommendation because the Pennsylvania Supreme Court, in a recent opinion, rejected the recovery of such costs in rates (Barasch v. Pa. P.U.C., 532 A.2d 325 (1987)). The Company has appealed this decision to the U.S. Supreme Court (probable jurisdiction noted, March 7, 1988). The ALJ stated that the Commission is required to follow the direction of the Commonwealth's highest court, and he also noted that ALJ Meehan had reached the same conclusion in his Recommended Decision in the Duquesne case. (Duquesne, supra, R-870651, Recommended Decision dated January 26, 1988, slip op. pp. 334-339). The result of this disallowance would be to reduce claimed expenses by \$1,495,215.

In its Exceptions, the Company excepted to the ALJ's recommendation on this issue (pp. 14-15). The Company noted that it has appealed the Barasch decision to the United States Supreme Court and, as noted, the Supreme Court has agreed to review this decision.

In its Reply Exceptions (pp. 15-16), the OCA stated that, as the Commission has recognized in its most recent Duquesne Order, the Barasch decision is controlling in this jurisdiction unless and until it is set aside or modified [*129] by the U.S. Supreme Court.

On review, we agree with the ALJ's recommendation on this issue, and so we disallow this item of expense. As stated by the OCA, we must follow the direction of the Commonwealth's highest court, unless the decision in Barasch is reversed by the U.S. Supreme Court. We, therefore, reduce the Company's claimed expenses by \$1,495,215 and, accordingly deny the Company's exception.

E. Depreciation Expense

The Company claimed nearly \$27 million for depreciation expense (PP Main Brief, pp. 104-107, 193-194, Appendix 7, p. 2).

The OCA and the OTS proposed adjustments to this item which would flow from their proposed rate base reductions; the three proposals involved the prudence of Perry I, Perry common facilities, and Beaver Valley I common facilities. The ALJ recommended that we reject the underlying OCA and OTS rate base proposals in the Rate Base Section of his Recommended Decision. Accordingly, a specific recommendation regarding associated depreciation expense was unnecessary. He added, however, that should the Commission decide to accept the OCA and

the OTS proposals on the Rate Base issues, then adjustments should be made to depreciation expense. [*130]

On the issue of the prudence of Perry I, no adjustment has been made, as discussed in the Rate Base section of this Opinion and Order. On the issue of Perry I common plant, we have decided to recognize only 50% of the common plant, also as discussed in the Rate Base section. Finally, we have decided to make no adjustments to rate base with regard to the Beaver Valley I common plant. Since we have reached these conclusions, we will make an adjustment for depreciation expense of \$1,221,000 for 50% of the Perry I common plant, as discussed in the Rate Base Section of this Opinion and Order.

F. Decommissioning Expense

The Company claimed the amount of \$229,179 for Beaver Valley I and \$53,485 for Perry I decommissioning expenses. The amount claimed for Beaver Valley I reflects a decrease of over \$93,000, which is due to the approval by the NRC of an extension of the plant's license by six years. The calculations of both amounts were based on studies performed for CAPCO, and these calculations reflect provisions for inflation and include an allowance for interest earned on escrow accounts established for both units (PP St. 3, pp. 3-6).

The OCA proposed an adjustment to this [*131] claim because it included the costs of demolition and the removal of both the radioactive portions and the non-radioactive portions of both plants. The OCA argued that the Commission had, in prior cases, established a policy of allowing decommissioning expense only for the radioactive portion of a nuclear plant (OCA St. 3, p. 39).

The ALJ recommended that we reject the OCA proposal on this issue. He based this recommendation on several bases. One basis was that in this Company's last rate case, Pa. PUC v. Penn Power, 85 PUR 4th, 323 at pp. 371-374, the Commission considered this same issue and decided to approve the Company's entire claim for decommissioning expense. The Commission in particular noted the testimony of a Mr. LaGuardia which stated that there were safety considerations to this issue, and that the removal of contaminated facilities would severely damage a large portion of non-contaminated structures. The ALJ also noted that ALJ Meehan, in the recent Duquesne case (Recommended Decision at R-870651 slip op. pp. 353-358) had reviewed this same proposed adjustment and had recommended that it not be adopted. Finally, stated the ALJ, given current requirements both [*132] in Ohio and Pennsylvania regarding abandoned structures, as well as legitimate concerns regarding safety and liability, the prudent course is to plan for removal of all the structures.

The OCA excepted to the ALJ's recommendation on this issue (pp. 32-33), again urging that an allowance not be made for that portion of the claim associated with the cost of decommissioning the non-radioactive portion of the plants. The OCA states that its argument on this issue was not based solely on its position that the Commission had established a policy of allowing decommissioning expense only for the radioactive portion of a nuclear plant. The OCA's position is, in fact, that the Commission should return to its former policy, as outlined in the case of Penn Sheraton Hotel v. Pa. PUC, 198 Pa. Super 618, 184 A.2d 324 (1962). The OCA further states

that the Commission had consistently recognized, in every decision prior to the last Penn Power case, that the allowance of a decommissioning expense in advance of a plant retirement is a narrowly defined exception to the general prohibition against the prospective recovery of negative net salvage as set forth in Penn Sheraton.

In response, the Company [*133] stated in its Reply Exceptions (pp. 19-20) that the legal argument presented by the OCA was fully addressed in the Company's Initial and Reply Briefs and was, for the reasons discussed in those Briefs, properly rejected by the ALJ. In addition, it states, the OCA's position was considered and rejected in the Company's last rate proceeding and in the recent Duquesne rate proceeding.

On review of this issue, we approve the recommendation of the ALJ, and we, therefore, reject the OCA proposal on this issue. As noted by the ALJ, we approved the full amount claimed for this item in Penn Power's last rate case. As also noted by the ALJ, there are safety considerations associated with this issue. The removal of contaminated facilities would severely damage a large portion of non-contaminated structures. Given current requirements both in Ohio and Pennsylvania regarding abandoned structures, the prudent course is to plan for the removal of all the structures. Accordingly, we deny the OCA's exception.

G. Spent Fuel Disposal Expense

The Company claimed \$1,471,845 to cover the cost of spent fuel (nuclear) disposal. The jurisdictional amount claimed for Perry I was \$285,145 (uncontested), [*134] while the amount claimed for Beaver Valley I was \$1,186,700 (contested).

The OCA proposed an adjustment to the allowance for Beaver Valley I, based on a capacity factor projection for that plant. The OCA witness used a capacity factor of 71%, drawn from the filing in the current Duquesne Light Co. rate case, Schedule I-B-2(a) for a test year ending March 31, 1988. The OCA also derived an 83% capacity factor from the data filed by Penn Power. Apparently the 71% factor was, in part, the result of planned outages for December, 1987 and January, 1988 (OCA St. 3, pp. 28-29).

The Company's witness acknowledged the apparent discrepancy, but he could not explain the derivation of either percentage. He noted that the claim was subject to an adjustment or "true-up" in a subsequent proceeding. He also pointed out that the Company has traditionally undercollected this expense, which is a liability incurred pursuant to a formula established by the U.S. Department of Energy (PP. St. 3-R, pp. 2-3; Tr. 189-194, 1135-1136).

The ALJ recommended that the OCA's proposed adjustment be rejected. He noted that the witness for the OCA could not provide support for his percentage (Tr. 822-825). [*135] The ALJ also rejected the OCA argument that this type of adjustment represents retroactive ratemaking, on the grounds that this position had been rejected by the Commission in the last Penn Power rate case (Pa. PUC v. Penn Power, 85 PUR 4th, supra, at pp. 374-376). Finally, stated the ALJ, the Company's position here appears reasonable and follows a methodology found acceptable by the Commission in the past. The ALJ admitted, however, that the method does potentially result in time period mismatches.

The OCA excepted to the ALJ's recommendation on this issue (OCA Exceptions, pp. 29-32). The OCA stated therein that the Company's spent fuel claim incorporated a capacity factor of 83% for Beaver Valley I, despite the fact that its own witness could not support his factor. The OCA recommended that a more reasonable capacity factor of 71% be used, asserting that there is no support in the record for the 83% capacity factor utilized by the Company. The OCA also argued that its suggested capacity factor of 71% was obtained from the then pending Duquesne proceeding. The ALJ apparently based his decision on the existence of a true-up mechanism. The OCA concludes by stating that [*136] the possibility of a later true-up does not and cannot relieve the Company of the burden of establishing the justness and reasonableness of its claim. There is no valid reason for the Commission to base rates on a capacity factor that is not reasonable.

In response, the Company stated in its Reply to Exceptions (p. 20) that the arguments advanced by the OCA were fully addressed and refuted in the Company's Initial and Reply Briefs. With regard to the OCA's criticisms of the "true-up" mechanism to reconcile over and undercollections of spent fuel costs, the Company stated that this mechanism has been approved in the Company's last two litigated rate proceedings and no party has opposed its continued use in this case. Finally, the Company noted that it has proposed to recover spent fuel costs through its current ECR.

As noted above, the Company has proposed to recover these spent nuclear fuel costs through its ECR filing, which is also pending before us. The Company made this proposal based on an informal recommendation of the Bureau of Audits. We agree that the better course is to allow these costs to be recovered through the ECR because the ECR mechanism is subject to annual [*137] reconciliation.

The incremental level of the Company's spent fuel disposal expense is directly dependent on the amount of energy generated by the Company's nuclear units (i.e. \$1.00/net MWH). The issue in the instant base rate proceeding is the projected level of generation that should be used to estimate the nuclear fuel disposal expense that would be incurred by the Company. By including this claim in the ECR, we can initially act upon the Company's claimed level expenses and then reconcile these expenses if the Company's actual generation levels (and corresponding nuclear fuel expenses) are greater or lesser than anticipated by the Company.

Since we have approved recovery of these spent nuclear fuel disposal expenses through the ECR, an adjustment will be made to remove the Company's claim from its base rate filing.

VI. TAXES

A. Deferred Tax Balances

The Company proposed the amortization of several deferred tax accounts. The Company's proposal is outlined in the following quotation from the prepared testimony of Company witness McDaniel.

Q. Does Penn power's income tax claim reflect any changes which were made as a result of the Commission's Decision at R-850267? [*138]

A. Yes. While the Commission's Decision at Opinion R-850267 is silent, there were three tax accounting changes which were adopted by the Administrative Law Judge in his Recommended Decision which were reflected in the Commission's revenue allowance, as set forth in Table II, to the Commission's Final Order. These changes deal with the treatment of income tax deferrals related to: (1) pension costs; (2) taxes capitalized; and (3) liberalized depreciation.

Q. Please address the Commission's treatment of pension costs.

A. Under pre-TRA86 tax law, the Company was able to take an income tax deduction currently for pension costs which were capitalized on the books of the Company with appropriate deferred taxes being provided TRA86 no longer permits a current deduction for capitalized pension costs. . . . As of April 30, 1987, the end of the historic test year, there was a balance of \$565,812 of deferred income taxes (both state and federal) related to previously capitalized pension costs. These amounts will be written off over a five-year period commencing August 1, 1987. Accordingly, in the future test year calculation, the Company has reflected the amortization [*139] of \$113,162, or one-fifth of the April 30, 1987 balance, as a reduction of income tax expense.

Q. Please comment on taxes capitalized.

A. The same facts that apply to pension costs also apply to taxes capitalized, and they were handled in exactly the same manner. As of April 30, 1987, \$1,092,276 of previously deferred income taxes (both state and federal) relating to capitalized taxes were available for amortization. One-fifth of this amount, or \$218,455, is reflected in the future test year as a reduction of income tax expense.

Q. How were the state liberalized depreciation deferrals handled?

A. After the write-offs of deferred state income taxes included in the Joint Settlement Petition, there remained certain state income tax deferrals relating to liberalized depreciation [T]he OTS recommended that these amounts be written off over a five-year period which adjustment was adopted at R-850267. As of April 30, 1987, \$1,556,955 of state income tax deferrals relating to the ADR benefit remained on Penn Power's books. One-fifth of this amount, or \$311,391, is reflected in the future test year as a reduction of income tax expense. Also, as of April 30, 1987, [*140] \$614,418 of state income tax deferrals relating to the ACRS benefit remained on Penn Power's books. One-fifth of this amount, or \$122,884 is similarly reflected in the future test year as a reduction of income tax expense.

Q. How were the federal liberalized depreciation deferrals handled?

A. The federal income tax deferrals in question relate to the DDB benefit of the 1980 property, which were not completely covered by the Joint Settlement Petition. Consistent with the Commission's decision at R-850267, Penn Power will write-off these deferrals over a five-year period. As of April 30, 1987, the deferred balance was \$1,235,781. One-fifth of this amount, or \$247,156, is included in the future test year as a reduction of income tax expense.

Q. How have these three items of deferred income tax which you just discussed been treated in the measures of value?

A. In light of the fact that these deferred income taxes are being written-off and returned to ratepayers in a short period of time, they have been removed from the measures of value. The net effect of Penn Power's treatment of these three items is a reduction of its revenue requirement. (Emphasis added)

pp St. [*141] 5, pp. 5-8.

Neither the OTS nor the OCA raised any objection to the proposed five year amortization. However, both voiced an objection to the complete removal of the deferred balance from rate base consideration. 2 Both the OTS and OCA proposed that the deferred balances of April 30, 1987 be only partially reduced. 3

The Company, in its Main Brief, argues primarily against a rate base reduction reflecting the entirety of the reserve balances. 4 The Company argues that these reserve balances should not, either in whole or part, be deducted from rate base, as the obverse of the situation where unamortized expense items are denied rate base recognition. The Company apparently has a fall back position which is that only a portion of the unamortized balances should be deducted from rate base, and the Company suggests a mid-point valuation (PP, M.B., p. 147).

[*142]

The ALJ seems to have understood that both the OTS and the OCA had advocated a rate base reduction equal to 80% of the April 30, 1987 deferred balances. 5 This would equate to the balance as of April 30, 1988, the end of the future test period, and reflect the future test year amortization, or one year of the proposed five year amortization.

The ALJ concluded that the 100% exclusion from rate base proposed by the Company was unreasonable. This was based upon the fact that, if completely removed, the Company would earn a return on the amortized balances of the reserves during the amortization period. He also concluded that inclusion in rate base of 80% of the reserve balances, was an equitable resolution of the matter. No party has excepted.

We agree that the Company's proposal is unreasonable. The Company's analogy of the exclusion from rate base of unamortized storm or tornado damage, which it specifically referenced as being experienced, is inappropriate. Our position regarding the exclusion from rate base of unamortized expenses has been repeatedly affirmed by our Appellate [*143] Courts. We would point out that there is no immutable regulatory principle which mandates that we permit amortization of either previously incurred or current one-time expenses. But for our grace on this subject, we would expect that many, if not all, one-time expenses would be expensed in the year of occurrence, as they would normally be treated for financial accounting purposes. 6

While according rate base recognition of 80% of these reserve balances, or the balance of the end of the future test period, is not the only ratemaking treatment which might be accorded these

items, we find that such treatment is clearly within the realm of reason and we adopt the ALJ's recommendation. Accordingly, we shall reduce rate base by \$3,552,264.

B. Alternative Minimum Taxes

The ALJ quoted a passage from the prepared testimony of Company witness McDaniel in order to frame this issue here. We, too, shall do so. McDaniel said that:

One of the more significant changes brought about by TRA86 is the requirement that 50% of the difference [*144] between federal taxable income and book, or reported, income must be treated as a tax preference item. The intent of Congress in enacting this legislation was to require corporations which report positive book income to pay some amount of income tax, even though under a regular tax calculation none would have been due. Penn Power is adversely affected by the AMT due to large amounts of AFUDC which enter into book income, but are not considered to be taxable income under the regular tax calculation. Penn Power is further adversely affected by virtue of large amounts of tax depreciation generated by the Perry 1 nuclear unit. As such, Penn Power is expected to be in an Alternative Minimum Tax position in 1987 and at least until such time as new rates become effective in this case. Further, under the AMT formula, the tax liability is so computed may only be offset to the extent of 25% by investment tax credits. This further reduces the amount of investment tax credit that the Company will actually be able to utilize during the period it is in an AMT position. However, under the provision of TRA86, the "premium" paid in one year as a result of the AMT may be used to offset the regular [*145] tax liability to the extent in excess of the AMT in subsequent years. Thus, if it is assumed that Penn Power's current AMT position is a temporary one, then Penn Power will be able to offset future years' tax liability with the AMT "premium" currently being paid. As such, Penn Power is not making a claim in current tax expense for the AMT premium, but rather is deferring the AMT and including it in rate base. Further, Penn Power's approach is conservative because only the amount of AMT incurred through April 30, 1987, has been included in the measures of value. This additional rate base is \$824,646. In this way, Penn Power will have an opportunity to earn a return on funds they have paid to the federal government but are not claiming currently from its customers. Of course, at some future period when the AMT is utilized, it will be removed from rate base.

PP St. 5, pp. 10-11.

Both the OTS and the OCA urged that we disallow the Company's rate base claims for this item.

The OTS objection is premised upon the assertions that Penn Power's additional Alternative Minimum Tax ("AMT") liability claim is based upon a separate return filing; however, in fact, it files a consolidated [*146] return with Ohio Edison, and on a consolidated return basis no AMT liability is incurred. The OTS further asserts that the Company has submitted no proof that AMT liability will be incurred on a consolidated basis. The OTS continues its argument and states that even if AMT liability is incurred on a consolidated basis, there should be no ratemaking recognition because AMT is temporary and can be utilized to "offset against future tax expense and should, therefore, be normalized for ratemaking purposes." 7

The Company responds and asserts that "the Ohio Edison System will experience AMT liability on a normal ongoing basis beginning in 1988" (Company R. Exc., p. 12).

The OCA asserts that Penn Power will not be in an AMT posture in the post-Future-test-year period. Therefore, says the OCA, it is inappropriate to reach back in order to recognize this one expense. The OCA also raises a question as to whether "this liability in fact will ever be paid" (OCA M.B., p. 11-12). This somewhat confusing statement is explained by stating [*147] that because AMT which is paid and deferred can be used to offset future tax liabilities, it is never paid. Thus, it seems that the issue raised by the OCA is not whether AMT liability will be paid, but whether it will remain paid or whether it will effectively be recovered at some future time. Accordingly, the OCA's concern seems to be the permanency of this deferred tax (asset) item, 8 similar to the OTS' assertion that their deferral was only temporary. However, neither the OTS nor the OCA has advised us regarding "how long" is temporary, in their view. The term temporary is an uncertain and ambiguous term, possibly ranging from a matter of seconds to thousands of years if we are viewing events from the context of the existence of the universe.

We must acknowledge that the balance of an AMT deferred tax amount will probably be very volatile as contrasted with the deferred tax reserve resulting from tax normalization for accelerated depreciation. We can envision situations in which an AMT reserve is built up over several years [*148] and then being zeroed in one year; and conversely, an AMT reserve being created in only a year or two and then being amortized slowly over a period of several years. Almost any scenario which can be imagined seems a possibility.

But the mere fact that an AMT reserve is less stable and less permanent than, for example, the reserve normalizing taxes associated with accelerated depreciation, is not sufficient reason to refuse to recognize its existence for ratemaking purposes. In our view, the permanency and volatility issues can be solved by normalizing the reserve balance in some manner. We shall leave this subject to the creative imagination of the parties in future proceedings. Since it clearly appears that the reserve balance would be approximately \$3.2 million by the end of the future test year, as contrasted with the Company's claim of \$824,646 which represents the balance at the end of the historic test year, it does not appear that any action is necessary to normalize the Company's claim. 9

[*149]

With regard to the matter of a separate return/consolidated return, the OTS has questioned whether on a consolidated return basis, the Ohio Edison System will be in an AMT situation in 1988. Company witness McDaniel testified that, based upon information available to him, the System would be in an AMT position in 1988. 10 We are satisfied that the Ohio Edison System will be in an AMT position in 1988.

The ALJ concluded that the Company's claim was reasonable and recommended that it be approved. Both the OTS and the OCA have excepted.

In its exception the OTS raised the matter of the hearsay nature of Mr. McDaniel's testimony which we have addressed in a footnote above. The OTS reiterated its comments regarding the

"temporary" nature of the AMT tax deferral which we have also addressed and disposed [*150] of above. We find no merit in the two points raised by the OTS in support of its exception and, accordingly, it is denied.

The OCA also reiterated its argument concerning the temporary nature of the AMT deferral. We need not address this matter again. The OCA also raised the issue as to whether the rate relief accorded to Penn Power in this proceeding would be sufficient to remove it from an AMT position. In this regard the OCA suggests that since a major factor underlying the AMT liability is the large amount of AFUDC associated with Perry Unit No. 1, there should be little AFUDC in the post-future test period. The conclusion reached is that "it is unlikely that Penn Power will be in an AMT position in the post-future test year period. It seems that it is the OCA's position that the Company must address the post-future test year period and demonstrate the factual situations which will then obtain. We disagree. We do not view the Company as having a burden of proof beyond the future test year period. It is the burden of other parties, such as the OCA, to demonstrate by a preponderance of the evidence that the facts and circumstances of the future test year will not obtain [*151] beyond that period, if it is to be successful with regard to a post-future test year adjustment. Speculation, which seems to be the extent of the OCA's position on this matter, is sufficient to satisfy its burden to support a post-future test year adjustment.

The OCA also argues that "allowance of the Company's claim will result in a real distortion of the test year expenses and revenues, as Penn power did not request recovery of any AMT liability it may incur in the future test period." (OCA Exc., p. 34). We are uncertain of the specific point being raised here. We do not follow how a rate base claim distorts revenues and expenses. Also, since any claim for AMT recognition must, for the same test period, take the alternative forms of either an expense or rate base item, not both, we fail to see how the Company can be expected to claim an expense to match its rate base claim. Also if there were some distortion by reason of the omission of an expense claim it is to the Company's detriment, not the ratepayers. Is the COA arguing that the Company should be denied a rate base claim because it is failed to make an expense claim?

The OCA also comments that out of period expenses [*152] can be recovered only in certain limited circumstances. We find this comment inappropriate since the Company is not seeking recovery of an expense. 11

We find no merit in the OCA's exception and, accordingly, it is denied. We adopt the ALJ's recommendation and adopt the Company's rate base addition claim in the amount of \$824,646.

C. Contributions in Aid of Construction

Another change in tax law included in the Tax Reform Act of 1986 was the requirement that contributions in aid of construction be included in taxable income. Penn Power, as does most utilities, following our customary ratemaking practice, deducted contributions in aid of construction from rate base, in order to reflect the fact that plant constructed with funds derived from such contributions, represents non-investor constructed plant. Penn Power does not currently recover the increased tax liability associated with such contributions from the contributor of the construction costs. Accordingly, it pays such tax liability from funds available

to it and records [*153] such payments as negative deferred taxes. 12➤ Penn Power proposes that this account, which reflects prepaid income taxes, be added to rate base as being investor supplied capital. 13➤ No party took direct issue with Penn Power's proposal, from either an accounting or ratemaking perspective. However, the OTS proposes that this claim be denied on the basis that it has pending before the Commission a Petition, at Docket No. P-870246, in which it proposes that the increase tax liability associated with contributions in aid of construction be recovered from the party necessitating the construction, with the result that investors would not be required to provide the funds to pay the tax liability associated with the contributions, and also in order that the general body of ratepayers be neither burdened with providing the funds nor providing a return on such funds provided by investors.

[*154]

The ALJ noted the OTS objective and proposal, but stated that "in the absence of a Commission policy statement" on the subject he recommended that the Company's claim be approved (R.D., p. 172).

The OTS has excepted reiterating its position. While we fully appreciate the OTS' position in this matter, the fact is that we have not resolved the issues raised in the OTS Petition, that is, we have not resolved the issue of whether customers necessitating construction in addition to any free construction undertaken by a utility to serve the prospective customers, as provided for in its tariff, should provide some or all of the additional funds necessary to pay the income tax liability associated with the required contributions. Until such time as Penn Power voluntarily institutes or is required to institute a tariff provision providing for the recovery of the increased tax liability from customers providing contributions, it has no choice but to pay the income taxes involved from investor funds.

We do not view the fact that the OTS Petition is pending our action as even a semblance of a basis for denying recognition of events which have already taken place or will take place before [*155] we have an opportunity to act. Accordingly, we deny the OTS exception, and approve the Company's claim.

D. Asset Depreciation Range

The Company's claim in this proceeding included the normalization of the difference in the income tax effect of the Double Declining Balance/Book Lives and the Double Declining Balance/Asset Depreciation Range for assets placed in service in 1971 through 1980. 14➤ This practice was first permitted in the Penn Power 1975 rate case proceeding.

The OTS raised two issues and proposed two adjustments with regard to Penn Power's claim. First, the OTS proposed a disallowance of the income tax expense associated with normalization of the income tax expense, in the amount of \$26,868. Second, the OTS proposed that we require the flow through of the current deferred tax reserve pertaining to the 1971-1980 plant, in the amount of \$7,032,584, over a period of five years, with a reduction to current [*156] income tax expense of \$1,406,517, and a concomitant increase in rate base of the same amount.

The Company argues that the OTS proposals be rejected for two reasons. First, that in a private letter ruling issued to Duquesne Light Company, which is factually pertinent to Penn Power, the Internal Revenue Service made it clear that a requirement to flow through the ADR Benefit would violate the normalization provision of the Internal Revenue Code. Much of the dispute between the Company and the OTS centers upon the significance of private letter rulings in general, and more specifically the lack of significance of one issued to another taxpayer. The ALJ addressed this dispute at some length, as did the parties. We do not feel constrained to address this matter in detail because that controversy has been mooted by the issuance of Revenue Ruling 87-137 on December 23, 1987. In pertinent part that ruling states that:

Once taxpayer adopted the normalization method of accounting section 167(1)(2)(c) of the Code no longer applies. Where taxpayer returned to flow-through accounting, taxpayer could not continue to use an accelerated method of computing depreciation.

In response, [*157] in its Reply Brief, the OTS quotes from a Commission Brief, dated September 29, 1987, to the Commonwealth Court of Pennsylvania in No. 598 C.D. 1986 and No. 599 C.D. 1986. The quoted passage addresses Federal Court decisions holding that Revenue Rulings and Private Letter Rulings can be retroactively revised by the Commission, since such rulings do not have the force and effect of law. The point which the OTS wishes to make through its Reply Brief comments is unclear.

The ALJ comments at page 177 of his Recommended Decision that, taken together, the Duquesne Light Company private letter ruling and the above cited Revenue Ruling establish "the real possibility of the loss of accelerated depreciation should this Commission order Penn Power to change to "flow-through" accounting for pre-1981 assets". We agree.

No one can predict with certainty the action which the IRS would take, were we to order Penn Power to flow through the ADR Benefit, nor can we predict the eventual outcome of court, litigation if it were pursued after adverse IRS action. However, the risk of Penn Power losing its right to utilize accelerated depreciation for income tax purposes is too great a risk for too [*158] small a benefit. The benefit which we are offered by the OTS proposal is an expense reduction for current income taxes of \$26,868 and an offset to current income tax expenses of \$1,406,517, partially offset by the revenue requirement effect of an increased rate base. 15

The Company has also raised the point that the turn around point for these pre-1981 assets is close at hand. This is a second circumstance enunciated by the Court in *Barash v. Pa. P.U.C.*, 547 Pa. 561, 493 A2d 653 (1984); that is, that the turn around point would be reached in the reasonably near future. We can only speculate what prompted the Court to include consideration of the nearness of the turn around point as a justification for normalization. But if it is a rational justification for permitting normalization, which we view it [*159] to be, it constitutes an even greater justification for rejecting amortization of the reserve balance, when the benefit derived from such amortization is a merely transitory short term benefit. 16

The ALJ recommended rejection of the OTS' proposed adjustments. The OTS has excepted. 17 In its exception, the OTS states that the ALJ erroneously and heavily relied upon a false statement by the Company which was that "the Company ultimately was never allowed to

normalize the DDB Benefit" (emphasis in original) (R.D. p. 178). The OTS goes on to describe that Penn Power was allowed to normalize the DDB Benefit in the Commission's Opinion and Order of January 22, 1982 at Docket Nos. R-811510, R-821918, and R-832409. The OTS continues and notes that such normalization continued until October 2, 1986, when, pursuant to a settlement agreement, Penn Power agreed to flow through the deferred Federal Income Tax attributable to the 1980 DDB Benefit. 18 From this, the OTS concludes that the 1980 DDB Benefits [*160] were subject to the same normalization provisions as are the taxes associated with the ADR benefit and the Company is already in violation of the IRS normalization provisions.

It is unclear to us what the OTS is urging us to do with its conclusion. However, our response is that the ALJ's comment that Penn Power was never permitted ultimately to normalize the DDB Benefit, which appears to be misunderstood by the OTS, appears to correctly characterize the sequence of events described by the OTS. The Commission Order in 1982 permitted normalization, the Supreme Court reversed and remanded and the settlement of the proceeding resulted in a refund of the amounts normalized. Thus, ultimately, normalization was not permitted. Whether this factual situation violates the IRS' normalization regulations, only the IRS can say. However, we find the factual situations clearly distinguishable.

We find the OTS argument in support of its exception to be without merit. Accordingly, it is denied. We also find that the Company's arguments in opposition [*161] to the OTS' proposed adjustments have merit. The Company persuaded the ALJ to recommend against the OTS' proposed adjustment, and they have, similarly, persuaded us. Accordingly, we reject the OTS' proposed adjustment.

E. Unprotected Deferred Tax Balances.

The OCA proposed an accelerated flow back of certain deferred tax balances which are "unprotected" under the terms of the Tax Reform Act of 1986. 19 The explanation of the proposed adjustment was set forth by the OCA's witness, as follows:

In preparing its case, the Company recognized for ratemaking only a part of the deferred tax balances arising from utility operations. This is evident when reviewing Schedule II-D-24(c). The largest value recognized is the deferred tax associated with Liberalized Depreciation in Account 282. A substantial number of deferrals were excluded from consideration in setting base rates.

Some of those exclusions are short-term in nature and will reverse quickly; e.g., energy costs. Others will not; e.g., nuclear fuel costs. The issue arises regarding the non-short-term deferrals which have been accrued at 46% levels but will be relieved at the lesser rate of 34%. An excess in deferred [*162] tax balances exist.

Section 203(e) of the Tax Reform Act of 1986 stipulates that excess reserve balances for property depreciation related deferrals cannot be reduced more rapidly or to a greater extent than such reserve would be reduced under the average rate assumption method; i.e., the remaining life

of the asset. All of the other deferrals on Schedule II-D-24(c) be flowed back at rates the Commission decides are appropriate

OCA St. 3, pp. 48-49

The Company's witness responds as follows:

. . . . A review of Witness Knudsen's testimony, coupled with the transcript of his cross-examination, does not reveal which specific items of deferred taxes he has in mind. Apparently he is referring to some or all of the income tax deferrals shown on Schedule II-D-24(c) except those which are "protected" under Section 203(e) of the Tax Reform Act of 1986 or those deferred taxes which may be included in [*163] Accounts 190 and 283. Witness Knudsen's proposal to, in effect, write down these deferred items to reflect the prospective 34% federal corporate income tax rate is inappropriate because the events which gave rise to these deferred income taxes are not recognized in Penn Power's cost of service. For example, deferred income taxes relating to deferred fuel costs result from the fact that fuel costs may be deducted for income tax purposes currently but are deferred on the Company's balance sheet for future recovery through the levelized energy adjustment clause. This creates a timing difference for which deferred income taxes are recorded. It would be unfair to immediately give the customer any portion of the income tax benefit without charging him with the fuel costs which gave rise to the benefit in the first place. For the most part, these income tax deferrals relate to balance sheet transactions which do not affect cost of service and which are not included in rate base.

Further, as I testified on cross-examination, the accounting profession has not yet decided on the disposition of deferred income tax balances, which historically have been provided at rates higher than 34%. [*164] Under the "liability method" being considered, companies would have the opportunity to immediately write-down their reserve to reflect the 34% liability. Under the alternative method under consideration, the deferred income tax balances would be preserved at their current level for future disposition. However, in this case, it makes no difference which of the two methods is finally adopted because the deferred tax items in question do not affect Penn Power's cost of service in any way.

PP St. 5R, pp. 4-5.

In its Main Brief, the OCA commented that its witness excluded items associated with the energy clause. The OCA also asserts that it is neither appropriate or practical for this Commission to refrain from making adjustments merely because the accounting profession has not issued guidance. The OCA closes by stating that "the Commission should direct that the unprotected deferred tax balances resulting from the reduction in the federal increase tax rate be returned to ratepayers over a three-year period" (OCA M.B., p. VI.-11). The line following this statement states that the calculation of the adjustment is shown on Table II of Appendix A and Sch. TEK-5 of Appendix B to [*165] the brief. No such calculation appears at the references provided. The information provided at Schedule TEK-5 says: "to be determined upon FASB ruling in December".

Although this subject is addressed in the OCA's Reply Brief, nothing additional of substance is provided.

In this posture of the OCA's proposal the ALJ stated that "given a certain lack of clarity and focus in the proposed adjustment, it is recommended that the OCA proposal not be adopted" (R.D., p. 180).

The OCA has excepted. Although of some considerable length, we think it appropriate to set forth the OCA's exceptions in haec verba.

The OCA proposed that the excess deferred tax balances not addressed by the Tax Reform Act of 1986 be returned to ratepayers over a three-year period. OCA Main Brief at VI-9 to 11, Reply Brief at 64. The Administrative Law Judge rejected this proposed adjustment, citing a ". . . certain lack of clarity and focus. . ." R.D. at 180. The OCA excepts.

The issue involves certain non-short term deferrals which had accrued at the 46% tax rate but which will be relieved at the lower rate of 34%. Because TRA86 specifies that excess reserve balances for property depreciation cannot [*166] be reduced less than ratably, the OCA limited its adjustment to the long-term, non-property related deferrals shown on Penn Power Sch. II-D-24(c).

That schedule lists the accounts which comprise the OCA's adjustment. As Mr. Knudsen stated on cross-examination, his adjustment includes all non-property, non-fuel related balances not reflected in the sixth column shown there, "Deferred Tax Balance Per Measure of Value":

"I want everything that is not property related, basically everything that is not in the 282 account viewed as a potential benefit, . . ."

Tr. 860; See also Tr. 857-61. In addition, OCA Exh. 12, the Company's response to OCA VIII-16, lists the various deferred tax balances. On cross-examination, Penn Power's witness agreed that all of these items, except those relating to depreciation, were unprotected in terms of TRA86. Tr. 440. Thus, there can be no doubt as to what accounts are included in the OCA's adjustment.

The OCA at the time of filing its brief was unable to quantify its recommendation, because the Company stated that it was awaiting guidance from the accounting profession as to how these balances would be treated.

Q. So, is the company going to [*167] comply with whatever FASB comes out with in December of 1987?

A. That is my understanding; that whatever FASB finally rules, the company will follow, I assume, to avoid their auditors taking exception to their final statements in 1987.

Q. And what would be done in the context of this proceeding?

A. I think it's likely to occur before this proceeding is over, yes.

Tr. 444, Cross-examination of Penn Power witness McDaniel. As Penn Power has not updated its filing to reflect any changes to these balances, all accounts, except those relating to depreciation and short-term items as testified to by Mr. Knudsen should be included in the adjustment.

Regardless of what the accounting profession ultimately decides the fact is that these balances are not subject to TRA86 restrictions (Tr. 440). Ratepayers paid the underlying expenses that gave rise to these deferrals and thus should receive the benefit of the reduction in the federal rate, as was done when excess balances resulted from the change in rate from 48% to 46%.

Therefore, the Administrative Law Judge's rejection of this adjustment should be reversed.

OCA Exc., pp. 35-37.

Although the Financial Accounting Standard [*168] Board issued its Statement of Financial Accounting Standards (SFAS) No. 96, Accounting for Income Taxes, dated December 1987, the OCA appears to have chosen not to address that Standard, even though the OCA had indicated that it was awaiting publication of the ruling in order to quantify its proposed adjustment.

We have examined the OCA's cited references, namely Penn Power Schedule II-D-24(c) and OCA Exh. 12. Based upon our examination of these exhibits we cannot determine precisely which accounts and balances the OCA witness was focusing upon, if indeed the proposal had been definitized which appears to us may not have been the case. Additionally, we are unable to determine what portion of the balances set forth represent the excess, i.e., the amount over and above a deferral at a 34% tax rate.

We do note, however, that the provisions of SFAS No. 96 requires regulated enterprises to reclassify a portion (the excess) of the deferred income tax balances as a regulatory liability. The assumption underlying such classification is that the regulatory intent and/or requirement is to provide for the benefit of reduced tax rates in future periods' rates. Such is our intent. Accordingly, [*169] although we shall not make provision for the amortization of excess deferred balances in this proceeding, because of the lack of specificity of the accounts and amounts involved, we hereby direct the Respondent to freeze the regulatory liabilities which the provisions of SFAS No. 96 provide be established, until further order of this Commission.

Consistent with the above discussion, we deny the OCA's exception.

F. Bad Debt Reserve

Prior to the Tax Reform Act of 1986 (TRA86), the Company was allowed to deduct for income tax purposes a provision for bad debt expenses, in an amount unrelated, in a given year, to actual bad debt write-offs. TRA86 provides that only the amount actually written-off within a given year is deductible for income tax purposes. TRA86 further provides that the income tax reserve for bad debts, i.e., the amount deducted in prior years and not written-off, must be added to taxable income over a period not to exceed four years, commencing January 1, 1987.

Accordingly, the Company adjusted its future test year to include in taxable income, the amount of \$98,071 (one-fourth of the December 31, 1986 reserve of \$393,284). This has the effect of

increasing [*170] current income tax expense (State and Federal) by \$38,846. The OTS proposes to disallow the Company's adjustment for the amortization of the bad debt reserve to taxable income, on the basis that ratepayers have already paid income taxes related to the amounts in the reserve. The OTS also asserts that the reserve for bad debts has been funded by ratepayers (OTS M.B., p. 49). The presumed relevance of this fact is not clear. However, the OTS also states that the Company has also made a claim in its cost of service showing for bad debts. From this fact, the OTS concludes that, therefore, ratepayers are entitled to a refund for the Tax Reserve for Bad Debts." (OTS M.B., p. 50). We are not certain of the reasoning (which the OTS has not supplied), which leads to this conclusion.

For its conclusion that ratepayers have previously paid the income taxes which would have been associated with prior ratemaking provisions for uncollectibles the OTS relies upon the testimony of its witness (OTS St. No. 9, pp. 21 & 26). However, that witness admitted, on cross-examination, that he had not researched and analyzed prior rate filings and Commission Orders to verify his conclusion (TR. 909-910). [*171]

Company witness McDaniel had stated in his prepared testimony, however, that:

This treatment is appropriate for ratemaking purposes because in prior years when the reserve for bad debts was being built up, it was treated as a good income tax deduction (which it was) for accounting and ratemaking purposes. Thus, the customers received the income tax benefit of the build-up in the reserve for uncollectibles. Now, under TRA86, Penn Power has to "pay it back" over a four-year period. It is only fair that those who received the benefit in the past bear the burden under TRA86. (Emphasis added)

PP St. 5, p. 5.

The OTS, in its Reply Brief, quoted testimony of Company witness McDaniel. That testimony, from transcript pages 407-408, and 417-418, appears at pages 40-42 of the OTS Reply Brief.

In his Recommended Decision, the ALJ provides the following quotations from the McDaniel testimony, at page 182.

. . . You are correct that the allowance for bad debts is a component of cost of service, and it is treated on a net of tax basis; that is, the customers, receive the benefit of the tax deductions associated with the provision. (Emphasis added)

Tr. 407-408

They paid the expense, [*172] but they also enjoyed the tax benefit. If it had not been tax deductible at the time, they would have paid more. (Emphasis added)

Tr. 418

They paid dollar for dollar because it was treated as a good tax deduction. If it weren't a good tax deduction and the tax reserve had been built up with post-tax dollars, then we wouldn't propose this adjustment. (Emphasis added)

Tr. 418-419

The ALJ concluded that the Company had supported its claim as being reasonable.

The OTS has excepted. 20🚩 We find nothing in support of such exception which has not been adequately addressed above.

Having reviewed the testimony both referenced and quoted above, we conclude that the Company has supported its claim, in that it has demonstrated that the ratepayers have not previously paid sums representing the income tax liability associated with the funds provided for and constituting the existing reserve for bad debts, which must now be included in taxable income. Accordingly, there will be no duplication of ratepayer supplied monies. Our evaluation of the testimony presented by the OTS is that it constitutes nothing more than conjecture [*173] and speculation, which warrants little evidentiary weight.

We have been remiss in the past in not commenting upon the disservice which is done to the ratemaking process when testimony is presented which is totally devoid of factual foundation. 21 🚩 The necessity for Administrative Law Judges and ourselves to sort through the ploys and gamesmanship of the parties does nothing but further complicate our already difficult and complicated process. 22🚩

Having concluded that the Company has supported its claim by the requisite degree of proof, it is appropriate that we deny the OTS exception.

G. Research Tax Credit

In its Main Brief, the OTS states that the Company claimed "the Credit for Increasing Research for actual income tax purposes" (OTS M.B., p. 50). The OTS then argues [*174] that fairness dictates that ratepayers should be given the benefit of at least part of such credits in the ratemaking process. The OTS also cites the ratemaking principle of matching revenues, expenses, rate base and taxes, and claims that this principle will be violated in this proceeding if credit is not given.

The OTS also claims that the "Credit for Increasing Research Activities expires at the end of 1988. 23🚩 From this the OTS opines that it is unlikely that an adjustment would be made in a future proceeding. We do not agree. If the Company becomes able to use the accrued and unutilized credits at some future time, we believe that ratemaking recognition would be appropriate, unless there is a valid impediment which we do not currently have in mind.

In its Main Brief the Company quotes the testimony of witness McDaniel which recites, at PPC St. 5-R, p. 15, that Sections 38(b) and (d) of the Internal Revenue Code specify the priority for the utilization of tax credits in following order: [*175] (1) investment tax credit; (2) targeted jobs credit; (3) alcohol fuels credit; (4) research credit; and (5) low income housing credit. Mr. McDaniel also stated that as of December 31, 1986, the Company had \$15,168,491 of unused investment tax credit and that it was estimated that as of December 31, 1988, the balance of unused investment tax credits would be \$11,464,491. He also opined that there was no possibility that the research credits earned in 1986 or 1987 could be used before 1989 at the earliest and that this would not be finally determined until September 1990 when the 1989 return will be finalized.

In its Reply Brief, the Company framed the issue in terms of whether the Company can take advantage of the research tax credits on a current or near term future basis, and concludes that the un rebutted evidence is that it cannot. The Company also characterizes that OTS' position as urging an adjustment notwithstanding the inability of Penn Power to utilize the credits.

The OTS did not make any substantive comments in its Reply Brief.

The ALJ, with little discussion, stated that since the credits "will not be actually used to reduce tax expense in the near future it is [*176] recommended that the OTS adjustment not be accepted" (R.D., p. 183). The OTS excepted by merely referencing the comments in its Main Brief. 24📌 Similarly, the Company's Reply to Exceptions merely references its Main and Reply Briefs.

We see little rationale for reducing current tax expense by reason of research tax credits which cannot be utilized under current tax law, other than that it would benefit the ratepayer. While there are many fictions indulged in during the ratemaking process, they have some rationale to support them. What the OTS urges here seems to be a complete departure from the reality of tax law, with no rationale to support it, other than that the ratepayers provided the funds with which to conduct research. Were we to take this step, the next would be to rewrite the tax law to suit ourselves, and provide for tax deductions which do not exist, merely because they benefit ratepayers, or abolish tax timing differences because they are inconsistent with our view of what would be beneficial to ratemaking procedures.

We view this subject as very similar to the amortization or utilization of investment [*177] tax credits. We have never utilized levels of investment tax credits in ratemaking, greater than those which can be utilized. 25📌 Similarly, we are not satisfied that there is a viable rationale for adopting the OTS' proposed adjustment and, accordingly, we conclude that it is inappropriate to utilize research tax credits to offset income taxes, which cannot be utilized on either an actual or ratemaking taxes basis. Therefore, we deny the OTS' exception.

H. Taxes Capitalized Under Transitional Rules

Another change occasioned by TRA86 is the non-deductibility of capitalized taxes for income tax purposes. As with many other changes, there are transitional rules. In the instance of Perry Unit No. 1, capitalized taxes qualify as a deduction for income tax purposes.

In its filing in this proceeding, the Company based its claim upon the premise that Perry Unit No. 1 qualifies for transitional rule treatment, for the purposes [*178] of depreciation expense and investment tax credits, but the company did not provide for the deduction of capitalized taxes.

The OTS proposed an adjustment to recognize the deductibility of capitalized taxes in the amount of \$114,867 without State Tax Adjustment Surcharge (STAS) rolled into base rates, and in the amount of \$117,858 with STAS rolled into base rates.

In its Main Brief, the Company did not oppose adoption of this proposed adjustment in the amount of \$117,858 (PP M.B., p. 222).

The ALJ recommended adoption of an adjustment reducing income tax expense in the amount of \$117,858. No party has excepted.

Having reviewed this matter, we agree with the comments and positions of the OTS and the Company, and the recommendation of the ALJ. We shall make an adjustment to income tax expense to reflect the deductibility of capitalized taxes pertaining to Perry Unit No. 1.

I. Investment Tax Utilization

In his direct testimony, OCA witness Knudsen recommended that the amortization of previously earned investment tax credits (ITCs) carried forward from prior years, be increased and to recognize the fact that as revenues increase, a greater amount of investment tax credits [*179] can be deducted from current tax expense.

Company witness McDaniel admitted that his calculation reflecting the proper deduction of investment tax credits, did not reflect any rate relief, i.e., increased operating revenues and taxable income.

In this regard the OCA draws our attention to the adjustments made in the proceedings at Pa. P.U.C. v. Pennsylvania Power and Light Co., 57 Pa. P.U.C. 559, 611 (1983) and Pa. P.U.C. v. Philadelphia Electric Co., 58 Pa. P.U.C. 7, 52 (1983). The Company did not comment upon this subject in either its Main or Reply Brief.

The ALJ recommended that we make an appropriate adjustment to reflect the revenue increase granted in this proceeding. No party has excepted.

We conclude that an appropriate adjustment to the amount of investment tax credits used as an offset to current taxes, reflecting the revenue increase authorized in this proceeding, should be made in this proceeding. Our Tables attached to this Opinion and Order will reflect an appropriate adjustment in the amount of \$428,000.

J. State Tax Adjustment Surcharge ("STAS") Roll-In.

As was noted by the ALJ, both the Company and the OTS propose the roll-in of the STAS into base [*180] rates, after the determination of the allowable revenue level in our Opinion and Order in this proceeding. 26

The ALJ recommended that the STAS be rolled into the base rates to be established at the conclusion of this proceeding. No party has excepted to this recommendation.

By Order entered on September 21, 1987, at Docket No. L-830092, we adopted final regulations pertaining to the Inclusion of State Taxes and Gross Receipts Taxes in Base Rates (52 Pa. Code § 69.51 et seq.). These regulations were published in the Pennsylvania Bulletin of January 8, 1988, and became effective upon publication. Section 69.55(1) provides that:

(1) Rate Case Method. If a utility has on file a State Tax Adjustment Surcharge or Gross Receipts Tax Rider at a rate other than zero, the State Tax Adjustment Surcharge and Gross Receipts Tax Rider shall be zeroed and the tax expense recovered by the surcharge and rider shall be rolled into base rates in the next general rate increase filed by the utility. If the utility

files a cost of service study with its proposed rate increase, the tax expense previously recovered through the surcharge [*181] and rider shall be allocated to the various classes of service in a manner consistent with the cost of service study. If a cost of service study is not provided with the rate filing, the surcharge and rider revenues shall be rolled into base rates by applying the same percentage rate to each class of service in order that there will be no effective change in total revenues recovered from each service classification as a result of the roll-in.

The amount of revenue to be rolled into base rates cannot be determined until the conclusion of this proceeding, because of the revenue sensitive nature of the Gross Receipts Tax and the Corporate Net Income Tax. It should be noted that our Table I, attached hereto, does not reflect the revenues associated with STAS in either the column headed "Pro Forma Present Rates", or in the column headed "Total Revenue". In the absence of a specific methodology to accomplish the roll-in, we shall provide the following procedure to be followed by the Company: (1) to roll existing STAS expense, based upon revenues at present rates, into existing base rates; (2) to determine future rates, based upon the incremental increase in operating revenues found [*182] reasonable in this proceeding; and (3) roll the incremental STAS revenue requirement, applicable to the incremental increase in operating revenues found reasonable in this proceeding, into base rates.

We caution Penn Power that we shall expect it to supply, in conjunction with its compliance tariff filing, detailed information establishing the correctness of its results at each step of the process. More specifically, Penn Power shall supply:

1. The details of the calculation of the STAS factor and revenue requirement, stated in total dollars, at present rates;
2. The details of the calculation of the STAS factor and revenue requirement, stated in total dollars, applicable to the incremental revenue requirement; and
3. A proof of revenues demonstrating that revenues at future rates do not exceed the sum of: (a) revenues at present rates; (b) the STAS revenue requirement at present rates; (c) the STAS revenue requirement application to the incremental revenue requirement; and (d) the incremental increase in operating revenues found reasonable in this proceeding.

VII. RATE OF RETURN

A. Introduction

Before commencing a discussion of the evidence before us regarding [*183] the appropriate cost of common equity, we shall engage in our customary review of the legal standards which are relevant to such determination.

A public utility is entitled to an opportunity to earn a fair rate of return on the fair value of its property. *Pennsylvania Gas & Water Co. v. Pa. P.U.C.*, 19 Pa. Commonwealth Ct. 214, 341 A.2d 239 (1975); *Keystone Water Company White Deer District v. Pa. P.U.C.*, 19 Pa. Commonwealth Ct. 293, 302, 330 A.2d 873, 877 (1975); *Riverton Consolidated Water Co. v. Pa. P.U.C.*, 186 Pa. Superior Ct. 1, 140 A.2d 114 (1958). Rate of return can be defined as:

. . . the amount of money a utility earns, over and above operating expenses, depreciation expense, and taxes, expressed as a percentage of the legally established net valuation of utility property, the rate base. Included in the 'return' are interest on long-term debt, dividends on preferred stock, and earnings on common equity. In other words, the return is the money earned from operations which is available for distribution among the various classes of contributors of money capital.

Public Utility Economics, Paul J. Garfield and Wallace F. Lovejoy (1964), at 116. The return authorized [*184] must not be confiscatory, and must be based upon the evidence presented. *Pittsburgh v. Pa. P.U.C.*, 165 Pa. Superior Ct. 519, 69 A.2d 844 (1949).

Although it is acknowledged that the fair rate of return and cost of capital are not always synonymous, we consider the "cost of capital" approach to be one of the important bases upon which a fair rate of return is determined. *Lower Paxton Twp. v. Pa. P.U.C.*, 13 Pa. Commonwealth Ct. 135, 317 A.2d 917 (1974); *Pa. P.U.C. v. Duquesne Light Company*, 54 Pa. PUC 695 (1981). In availing ourselves of this generally accepted method of arriving at a fair rate of return, we, the ratemaking authority, first examine the utility's capital structure to identify the sources of the utility's capital and accompanying ratios. We then ascertain the cost of each component; namely, the cost of debt, determined essentially by the annual interest requirement of the utility's bonds, the cost of preferred stock, and the cost of common stock (common equity), determined by the return required to sell such stock upon reasonable terms in the market. *Pa. P.U.C. v. The Bell Telephone Company of Pennsylvania*, 57 Pa. P.U.C. 639 (1983); *Pa. P.U.C. v. Pennsylvania Power Company*, 55 Pa. P.U.C. 552 (1982).

Regardless of the procedure employed in determining fair rate of return, we must exercise "informed judgement". As we stated in *Pennsylvania Power*:

The return finding should consider the financial costs being incurred, so that the utility has the opportunity to recover its present cost of capital or to attract needed capital at reasonable cost. A fair rate of return for a public utility, however, is not a matter which is to be determined by the application of a mathematical formula. It requires the exercise of informed judgement based upon an evaluation of the particular facts presented in each proceeding. There is no one precise answer to the question as to what constitutes a proper rate of return. The interests of the company and its investors are to be considered along with those of the customers, all to the end of assuring adequate service to the public at the least cost, while at the same time maintaining the financial integrity of the utility involved. (Emphasis supplied).

Id. at 579. Moreover, we must adhere to the legal constraints which guide our decision.

In the landmark case of *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923), the United States Supreme Court addressed the issue of fair rate of return for a public utility. In *Bluefield*, the Court stated:

What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgement, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the

property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country in investments in other business undertakings which are attended by corresponding risk and uncertainties; but it has no constitutional rights to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate [*187] of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business generally.

Id. at 692-693.

In establishing the standards to be applied in implementing the Federal Natural Gas Act, the United States Supreme Court, in *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), said:

The rate-making process, under the Act, i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interest . . . "[R]egulation does not insure that the business shall produce net revenues." (Citations omitted)

But such considerations aside, the investor interest has legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. The return, moreover, [*188] should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Id. at 603.

As noted in these cases, we are required to approve as just and reasonable, rates which will produce revenue sufficient to enable the utility to recover all reasonable operating and maintenance expenses, depreciation and taxes. Additionally, the utility is entitled to have an opportunity to earn a fair rate of return on the capital invested in the enterprise. *Pa. P.U.C. v. North Penn Gas Company*, 55 Pa. P.U.C. 425 (1981). We stated in *Pa. P.U.C. v. Philadelphia Electric Co.*, 52 Pa. P.U.C. 772 (1978):

Among the factors to be considered in determining a fair return are (1) the earnings which are necessary to assure confidence in the financial integrity of the utility and to maintain its credit standing; (2) the payment of dividends and interest; and (3) the amount of the investment, the size and nature of the utility, its business and financial risks, and the circumstances attending its origin, development and operation.

Id. at 808.

Finally, we must engage in an appropriate balancing of the rates charged to the customers, [*189] for the services provided, with the return to which investors in the enterprise are entitled to have an opportunity to earn.

B. Capital Structure

The Company proposed a capital structure of: (1) 48.4% debt; (2) 14.2% preferred stock; and (3) 37.4% common stock, which represents its estimated capital structure as of April 30, 1988, the end of the future test year. No party took issue with the Company's proposal. The ALJ recommended its adoption.

We find the proposed capital structure to be reasonable and economical and, therefore, perceiving no reason to consider the use of a hypothetical capital structure, we adopt such capital structure for the purpose of determining a fair rate of return in this proceeding.

C. Cost of Debt

The Company claimed an estimated April 30, 1988, debt cost rate of 10.15%. No party took issue with this claim. The ALJ recommended that we adopt the Company's proposed cost rate. We find the Company's projected cost rate of 10.15% to be reasonable and, accordingly, adopt it for use in this proceeding.

D. Cost of Preferred Stock




The Company claimed a projected preferred stock cost rate of 9.89%, as of April 30, 1988. No party took issue [*190] with this claim. The ALJ recommended that we adopt the Company's proposed cost rate. We find that the Company's projected cost of rate of 9.89% to be reasonable and, accordingly, adopt it for use in this proceeding.

E. Cost of Common Equity

Testimony on the subject of the cost of common equity was presented by Paul R. Moul, Vice-President, Associated Utility Services, Inc., on behalf of the Company; Dr. Matityahu Marcus, Professor of Economics, Rutgers University, on behalf of the Office of Consumer Advocate; and Mr. John J. Steslow, Supervisor, Rate of Return Section, Office of Trial Staff, on behalf of that office.

When addressing the issue of the cost of equity, we have come to expect a wide range of cost estimates. Therefore, the controversy which is present here is to be expected. Due to the extensive record developed on this issue, we shall not be able to note or comment on every point, observation, supporting argument or criticism presented by the parties. However, this does not mean that we have not considered material which is not specifically addressed in the discussion below.

The following table and footnotes, provided by the ALJ at page 14 of his Recommended [*191] Decision, Summarize the methodologies, conclusions and recommendations of the various witnesses:

	Penn		
Methodology	Power 1 	OCA 2 	OTS 3 
	%	%	%
Discounted Cash Flow	14.25	12.25	11.65-12.5
Risk Premium	15.25		
Capital Asset Pricing			
Model			13.05
Earnings/price ratio			12.5 -13.5
Recommendation	14.75	12.25	12.5 -13.0

* Penn Power, OCA and OTS have all adjusted the dividend yields of their respective DCF calculations to reflect next period growth (Penn Power Statement 4, p. 40; OCA Statement 1, p. 20; and OTS Statement 1, pp. 12-13). Penn Power adjusted its DCF by 25 basis points to reflect investment risk differences (Penn Power St. 4, p. 56). OTS adjusted the dividend yield component of its DCF calculation to reflect market pressure and selling expense (OTS St. 1, p. 13).

1. Comparison Companies or Groups

Mr. Moul employed a barometer group [*192] of five companies, based upon the following criteria:

1. SIC Code of 4911 (electric service) or 4931 (electric and other services combined);
2. actively traded common stock;
3. have not reduced or eliminated dividends on common stock;
4. operate in Pennsylvania, Ohio, or New York;
5. have at least 85% of their 1986 operating revenues from electric sales; and
6. have a major generating plant construction program.

These criteria yield the following five companies: Centerion Energy Corp.; Central Hudson Gas & Electric Corp.; New York State Electric & Gas Corp.; Ohio Edison Company; and

Philadelphia Electric Company. Mr. Moul also looked to certain data pertaining to the Standard & Poor's 21 Electrics and Standard & Poor's 40 Public Utilities.

OTS witness Steslow utilized a barometer group of 6 electric utilities, consisting of: Centerion Energy Corp.; Central Hudson Gas & Electric Corp.; Duquesne Light Company; New York State Electric & Gas Corp.; Niagara Mohawk Power Corp.; and Philadelphia Electric Company. The primary consideration in Mr. Steslow's selection of his barometer group was "involvement in nuclear power generation to some degree since Penn Power's [*193] partial ownership of Perry 1 has had a major impact in its cost of capital" (OTS St. No. 1, p. 8). Mr. Steslow also noted that comparability of the six companies with Ohio Edison was demonstrated by the fact that the average of the company betas is .75, identical to that of Ohio Edison. He additionally noted that Value Line's average ranking for the six companies is 4/4 while the Ohio Edison ranking is 3/4 (OTS St. No. 1, p. 9).

Dr. Marcus utilized a group of 79 electric utilities consisting of "all electric utilities listed on the New York Stock Exchange which are also covered by Value Line, excluding utilities which have reduced or eliminated their common stock dividends" (OCA St. No. 1, p. 8). 27 Dr. Marcus utilized a large group because he is of the view that there is no agreement for identifying utilities which can be deemed of equal risk and, as a consequence, selection criteria which are formulated for a particular proceeding may produce a biased group.

2. Discounted Cash Flow

In this proceeding all three analysts have performed analyses utilizing the discounted cash flow methodology. The basic formula is: [*194] $k = D / p + g$, where k is the investors capitalization rate (or cost of capital), D is the current dividend, P is the current market price, and g is the anticipated future growth rate of dividends.

The DCF analysis is a market-based technique which is founded upon the principle that the amount an investor will pay for a share of common stock is based upon the present value of anticipated future dividends and appreciation in market price. Pa. P.U.C. v. Dauphin Consolidated Water Supply, 55 Pa. P.U.C. 44 (1981); Pa. P.U.C. v. Pennsylvania Power Company, 55 Pa. P.U.C. 552 (1982). In theory, the DCF method analyzes what an investor expects to receive, as opposed to what he would like to receive, as a return on the investment made.

The DCF methodology is not without its infirmities. The Market price of a stock reflects both the current and future investor expectations regarding growth in earnings, and, hence dividends. Therefore, a separate consideration of growth rates, either in earnings, dividends, or book value (reflective of earnings retention) could result in the duplication of a growth estimate which is already reflected, in part at least, in market price. Moreover, normally [*195] market price will also reflect present inflation and an assumption regarding future inflation. Pa. P.U.C. v. Pennsylvania Power Company, supra.

It should also be noted at the outset that there are a number of implicit assumptions in this methodology. First, that the payout ratio will remain constant over time, in order that the rate of

growth of dividends will track or equal the growth of earnings. Second, that the price/earnings ratios will remain constant, or at least be the same at the time of sale as the time of purchase.

a. Mr. Moul

Mr. Moul developed a five year (1982-1986) average dividend yield for his barometer group of 12.1%. The 12 month yield for the period ending June 1987 was 9.8%. Mr. Moul adjusted this yield by one-half of his derived growth rate (or 2%) and derived an adjusted yield of 10.0% ($9.8 \times 1.02 = 10.0\%$). 28

[*196]

In order to develop a growth rate Mr. Moul looked to Value Line and the Institutional Brokers Estimate System ("IBES") a service of Lynch, James & Ryan, a New York Stock Exchange member securities broker service. IBES provides data on consensus earnings per share forecasts and five year earnings growth rate estimates. Mr. Moul's growth rate estimates appear in his Schedule 11 and the averages for his barometer group are as follows: (1) IBES mean (1.15%), median (1.98%); and (2) Value Line's dividends per share average of (-0.7%) and percentage retained to common equity of +2.8%. With regard to his barometer group Mr. Moul also looked at five-year average compound growth rates in dividends per share of +4.1% (Schedule 12).

By a process which is far from clear to us, Mr. Moul settled upon a 4% growth rate to use in his DCF analysis, for a DCF indicated cost of capital of 14.0%.

Mr. Moul, however, was not finished. He advocated an upward adjustment of his 14.0% result, by 25 basis points to account for Penn Power's substantially lower common equity ratio and, hence, its significantly greater financial risk. Thus the result of his DCF analysis was, in fact, 14.25%.

Mr. [*197] Moul later stated that, between the time that his direct testimony was prepared in July 1987, and the time of his cross examination in October 1987, the cost of capital increased substantially, and that if conditions remained the same he would be inclined to raise his original equity recommendation by a full percentage point (TR., p. 7).

During the rebuttal phase, by merely updating his dividend yield to reflect the then most recent 12 month period for the barometer group, he produced a DCF indicated cost of common equity of 15.0%, before the 25 basis point adjustment for the cost associated with Penn Power's lower equity rates. This resulted in a 15.25% DCF indicated cost of common equity determination by Mr. Moul.

b. Mr. Steslow

Mr. Steslow developed dividend yields for the 12 months ending September 30, 1987 and a spot yield as of the date for both his barometer group and for Ohio Edison. These were as follows:

	12 months	Spot
Barometer Group Average	10.3	10.08
Ohio Edison	9.4	9.5

Mr. Steslow utilized the 12 month average yields in his DCF analysis. When adjusted by one-half of his adopted growth rate, the yields for the barometer group and Ohio Edison [*198] became 10.4% and 9.5%, respectively.

Mr. Steslow also adjusted the dividend yields by 1.5% to reflect market pressure and selling expense and the yields, thus, became 10.56% (10.40 divided by .985 = 10.56%) and 9.64% (9.50 divided by .985 = 9.64%), respectively.

In order to determine an appropriate growth rate Mr. Steslow looked to Value Line for both historic and projected growth rates for the barometer companies and for Ohio Edison. He also looked at the five year growth forecasts of earnings by IBES. With regard to future growth, Value Line estimates that the average earnings of the barometer group will grow at a negative 1.4% rate and the average dividends will grow at a negative 1.5% rate for the period 1984-86 to 1990-92. Similar data for Ohio Edison is an earnings growth rate of 1.5% and a dividend growth rate of 2.0%. The IBES estimates an average growth in earnings for the barometer group of 1.07% and for Ohio Edison of 1.55%. 29

Based upon an average forecast of an IBES growth rate in earnings of 1.07% for the barometer group, and an average historic 10 year growth rate in earnings of 3.7% and an average historic [*199] 10 year growth rate in dividends of 3.9%, he settled upon a growth in dividend rate of 2.0%. 30

Combining his adjusted dividend yield of 10.56% for the barometer group with his adopted growth in dividend rate of 2.0%, yielded a DCF indicated cost of common equity for the barometer group of 12.56%.

Using Ohio Edison as a proxy for Penn Power, Mr. Steslow combined his adjusted dividend yield of 9.64% with a growth in dividend rate of 2.0%, resulting in a DCF indicated cost of common equity for Ohio Edison of 11.64%.

c. Dr. Marcus

With regard to Ohio Edison Dr. Marcus found a 9.4% dividend yield for the 12 months ending September 1987. He also indicated that the yield could increase by 0.1% if the October 1987 dividend yield were included. He adjusted this yield by one-half of his adopted growth rate to 9.62% (9.5% x 1.013 = 9.62%), in order to reflect the projected increase in dividends in the first year.

With respect to an appropriate growth rate Dr. Marcus chose not to rely upon historic trends but, rather, focused upon retained [*200] earnings growth and industry analysts' growth projections.

Based upon the period 1981-1986, Dr. Marcus found an average earnings on common equity of 14.7% for Ohio Edison. Combining this with an average retention rate of 0.22, yielded a retained earnings indicated growth rate of 3.23%. During the same period, the average earnings, on common equity for the industry as a whole was 14.2%, which, when combined with a retention rate of 0.29, resulted in a retained earnings indicated growth rate of 4.12% (Schedule MM-16). The 1986 growth rates for Ohio Edison and the industry were 3.28% and 3.95%, respectively.

Turning to analysts' growth projections for Ohio Edison, Dr. Marcus found that IBES consensus forecast for September 1987 was 1.5%, which reflects the estimates of 14 individual analysts.

Considering the retained earnings growth rate range of 3.2% to 3.8% and the IBES projection of 1.5%, Dr. Marcus settled upon a growth rate of 2.6%. Combining his adjusted dividend yield of 9.62% and his adopted growth rate of 2.6%, resulted in a DCF indicated cost of common equity of 12.22%, which Dr. Marcus rounded to 12.25%.

Dr. Marcus conducted a similar analysis for the electric industry [*201] as a whole and determined at a cost of 12.0%. In doing so, he utilized an adjusted dividend yield for the 12 months ending September 1987 of 7.5%. Using the same methodology employed for Ohio Edison, he settled upon a growth rate of 4.5%. The combination of these two inputs total 12.0%.

Giving Penn Power the benefit of the highest of his two inputs, Dr. Marcus recommended a common equity cost rate of 12.25%.

3. Risk Premium

There are a variety of methods of conducting a risk premium analysis. Some analysts attempt to quantify a risk premium associated with an equity investment, over a risk free investment, such as a Treasury Bond. Other analysts quantify a risk premium associated with an equity investment over and above a fixed income security such as a utility bond. Mr. Moul, the witness for the Company, used the latter approach. He observed that for the 12 month and 1 month periods ending June 30, 1987, the yields on A-rated public utility bonds were 9.31% and 10.02% respectively. Mr. Moul also states that the forecast yield on A-rated public utility bonds for the 3rd and 4th quarter 1987 and the first three quarters of 1988 was approximately 10.0%, according to the [*202] July 1, 1987 Blue Chip Financial Forecasts. Mr. Moul also demonstrated (Exhibit 4A, Schedule 8, page 5) that the 12 month average bond yield of his barometer group for the period ending June 1987, was 9.72%.

Mr. Moul concludes that the long term borrowing rate for Penn Power would be about 50 basis points higher, taking into consideration its lower bond rating (S&P -- BBB, Moody's -- Baa3). 31✚ Accordingly, he selected a bond yield of 10.5% to use in his risk premium analysis.

In order to determine the risk premium, Mr. Moul examined studies performed by Ibbotson and Singuefield. This review revealed that the spread between the return on electric utility common stocks and long term public utility bonds was 3.42%, on a geometric mean [*203] basis; 6.34% on a median basis; with the mid-point of that range being 4.88%. This analysis encompassed the years 1928 through 1985. Utilizing a shorter period, that is, the years 1952-1985, the differential is 5.52%, on a geometric mean basis; 6.68% on a median basis; with a mid-point of that range of

6.60%. After looking at the S&P 40 Public Utilities, whose premium, on an arithmetic mean basis, is 5.37%, and electric utilities whose premium, on an arithmetic mean basis, is 5.78% 32, Mr. Moul concluded that an appropriate risk premium for Penn Power is 4.75%. Combining this risk premium with a prospective bond yield of 10.50%, determined as indicated above, Mr. Moul arrived at his 15.25% risk premium determined cost of common equity for Penn Power.

Subsequently, in his rebuttal testimony (PP St. 4-R, pp. 22-23), Mr. Moul noted that if more recent debt cost projections were used, i.e., December 1987, the comparable risk analysis would yield a cost of common equity for Penn Power of approximately 15.75%.

4. Capital Asset Pricing Model ("CAPM").

An additional analysis performed by OTS witness Steslow utilized the Capital Asset [*204] Pricing Model. Reduced to simple terms, the theory states that the expected return on equity is equal to the risk-free return, plus a premium for bearing risk. This description sounds almost identical to the theory underlying Mr. Moul's risk premium method. However, there is a difference in approach in determining the risk premium. First, rather than utilizing a segment of the market in measuring the premium of an equity return over a fixed income security such as a corporate bond, the risk premium under the CAPM method measures the risk premium of a well diversified portfolio (consisting of at least one share of all stocks traded in the market) over and above a risk free return (Treasury security), rather than a corporate bond. The second step is to adjust the result by the beta of the firm under consideration. 33

The formula for CAPM may be stated as follows: $COEC = N + (B \times RP)$, [*205] where "N" is the riskless rate of return, B is the beta (in Mr. Steslow's presentation the average beta of his comparison group is .75), 34 and RP is the risk premium (in Mr. Steslow's analysis, the risk premium developed in the Ibbotson-Singuefield studies for the period 1926-1986).

Mr. Steslow chose not to use long term treasury bonds of 20 years as the riskless rate, because to do so suggests that the investment horizon for most investors is 20 years. Noting that Ibbotson's yearbook designates the U.S. Treasury bill return as the risk free rate, he used the highest projected interest rate of six quarters of T-Bills ending with the December 1988 quarter, as projected by Standard & Poor's in their Outlook, dated August 1987. This rate is 6.60%. Mr. Steslow then developed a risk premium of 8.6% by subtracting the 3.5% arithmetic mean annual return for U.S. Treasury Bills from the 12.1% arithmetic mean annual return on common stocks (S&P 500) for the period 1926-1986. The CAPM formula is then solved as follows: $6.6\% + .75(8.6\%) = 13.05\%$, resulting in Mr. Steslow's [*206] CAPM derived cost of common equity for Penn Power of that level.

5. Earnings/ Price Ratios

It has been a long time since we have had a cost of capital witness present an earnings/ price ratio analysis. Mr. Steslow quoted from an article in the March 12, 1979 issue of Fortune titled, "The Stock Market Should Be Twice As High As It Is", by way of explanation of the theory of earnings/ price ratios.

The market price of any stock is supposed to be equal to the present value of the future stream of the company's earnings. In essence, present value is determined by dividing current earnings by the capitalization rate -- or rate of return -- that seems appropriate. In effect, the capitalization rate is the reciprocal of the earnings multiple. A company that has a record of highly stable earnings may succeed in getting investors to accept a capitalization rate of, say, 8 percent. If that company earned a dollar a share, its stock would then sell at around \$12.50 -- twelve and a half times earnings. Another company whose earnings outlook was riskier might find investors investing on a capitalization rate of, say, 20 percent. Its earnings would therefore command a multiple of only [*207] five in the marketplace.

Mr. Steslow set forth on his Schedule 7, p. 2, of OTS Ex. No. 1-A, a ten year historical comparison of the earnings price ratios of Ohio Edison and the six company barometer group for the years 1977 to 1986. He concluded from the earnings/ price ratios shown there that investors have capitalized Ohio Edison somewhat more favorably than the barometer group (average), except for the years 1984 and 1985, where the barometer group average was 17.2% in 1984, and 15.5% in 1985, contrasted with 20.8% and 16.4% for Ohio Edison for those years. In 1986 the average was 12.6%, contrasted with 12.8% for Ohio Edison.

Mr. Steslow then prepared a schedule in which he undertook to discern the direction with investors have taken in their assessment of electric utility investments, as reflected in the barometer group and Ohio Edison (OTS Ex. No. 1-A, Sch. 7, p. 7). There he demonstrated that the 1986 earnings/ price ratios varied, on average, from 17.6 to 10.6% for the barometer group, based on the 1986 price range and earnings. For Ohio Edison the range of earnings/ price ratios was 15.5 to 11.0%. Based upon September 30, 1987 closing price and earnings for the 12 months [*208] ending June 30, 1987, the barometer group average price/earnings ratio was 15.4%, while that of Ohio Edison was 12.5%. A similar calculation using the September 30, 1987, closing price, and the 1987 earnings estimate of Salomon Brothers produced an average price/earnings ratio for the barometer group of 12.1%.

From his array of data Mr. Steslow arrives at a price/earnings ratio indicated cost of common equity, although he has not provided a rationale between his data and his conclusion.

Mr. Steslow advocated an adjustment to his earnings/ price ratio conclusion, one percent for market pressure and one-half for selling expenses, even though knowledge of a new issue year in advance. 35 This allowance has already been included by Mr. Steslow in his 12.5% to 13.5% earnings/ price ratio conclusion.

Having reached the following indication of the cost of common equity:

DCF	11.65 - 12.50%
CAPM	13.05%
E/P Ratio	12.50 - 13.50

Mr. Steslow arrived at a cost of common equity [*209] conclusion for Ohio Edison of 12.50-13.00%.

6. Discussion

Much of the briefing of the parties as well as the direct (in some instances) and the rebuttal testimony of the witnesses is devoted to critiques and criticisms of the evidentiary presentations of other parties. Based upon our review of these critiques, both as to the inherent flaws of various analytical methodologies, as well as to the particular method of application by a witness, we conclude that many of the criticisms are valid. We do not find it necessary, however, to review and comment upon these criticisms; if we were to do so, and reject all the evidence with is flawed in some manner, we could well find ourselves with no "unflawed evidence" to consider. We do assure the parties, however, that criticisms and critiques, whether contained in the briefs of the parties or in witness testimony have been reviewed in great detail, and where found to have merit, we have accorded the evidence in question only such weight as we deem it deserving.

a. Discounted Cash Flow

The ALJ provided a table which summarized the DCF conclusions reached by Mr. Moul, Mr. Steslow and Dr. Marcus. We shall set forth this table below. [*210]

	Penn Power 1 📌	OCA 2 📌	OTS 3 📌
	%	%	%
Dividend Yield	9.8	9.5	9.4-10.3
Growth Rate	4.0	2.6	2.0
DCF Finding	13.8	12.1	11.4-12.2

The dividend yields set forth by the ALJ are the yields calculated by each analyst, without adjustment for one-half of his determined growth rate. All three analysts adjusted [*211] the dividend yield by one-half of his individually determined growth rate, to reflect the investor's anticipation of an increase in dividends and also to recognize the periodicity of dividends. In most, if not all, recent general rate increase proceedings, we have routinely adjusted dividend yields. This adjustment is, in effect, a refinement of the basic DCF formula, which we have set forth and described above, which is referred to as the "Gordon" model, so named for Myron J. Gordon, one of its ardent proponents in the mid-1950's.

The adjusted dividend yields determined by the analysts are: (1) Mr. Moul -- 10.0%; Mr. Steslow -- 9.5%-10.4%; and Dr. Marcus -- 9.62%. Dr. Marcus' 9.62% and Mr. Steslow's lower 9.5% figure, were both derived from data pertaining to Ohio Edison. We are inclined here to rely more upon a broader segment of the market as represented by Mr. Moul and Mr. Steslow's barometer groups, since there is a degree of circularity in determining a cost of common equity for Penn Power by only relying upon cost data applicable to its parent. We believe that an appropriately adjusted dividend yield to utilize in this proceeding, is in the range of 10.0%-10.4%. [*212]

For a growth factor we have a wide range from Mr. Steslow's 2.0% to Mr. Moul's 4.0% with Dr. Marcus toward the lower end of that range at 2.6%.

All of the analysts looked at historic growth rates and either IBES or Value Line projections, or both. In the case of Dr. Marcus, he calculated historic growth rates as indicated by retained earnings.

From an array of figures it seems that each analyst leaped to a growth rate conclusion, since no rationale leading from the data to a conclusion has been provided. Perhaps they were as confused as we, as to why, with historic growth approaching 4.0%, the IBES and Value Line forecasts reflect negative growth. We conclude that the forecasts reflect problems which the barometer group companies are expected to encounter, which is not apparent from the data furnished. With regard to Penn Power, with its nuclear construction program completed and the expectation that its future construction will be accomplished entirely with internally generated funds, we believe that an investor growth expectation in the range of 2.4%-2.6% is reasonable.

Accordingly, we find a DCF indicated cost of common equity in the range of 12.4%-13.0% to be reasonable. [*213] 36

b. Risk Premium & CAPM

Although Mr. Moul's risk premium and Mr. Steslow's CAPM analyses are different, they do have similarities, in that they both quantify the premium earned [*214] by an equity investment, over a fixed income investment, during an historic period, and then add that premium to the current return on a similar fixed income investment. In the instance of Mr. Moul, the fixed income investment was an A-rated utility bond. In the instance of Mr. Steslow, the fixed income investment was a T-Bill. Because of the difference in risk involved in these two fixed income investments, the premiums derived varied greatly, Mr. Moul's was 4.75%, while that of Mr. Steslow was 8.6%. The CAPM method does have the added attribute of adjusting the risk by the beta of the enterprise for which one is attempting to determine a cost of capital.

However, there are two objections which are shared by each methodology which we find to be an insurmountable impediment to placing much, if any, weight upon the results. They are: first, we cannot accept that historic experienced earnings reflect the cost of capital. We know of no reputable analyst who would seriously argue that experienced earnings represent the cost of capital, except by pure happenstance. But, such is the inherent assumption of each methodology. Second, we cannot accept, even assuming that historic [*215] experienced earnings represented the cost of capital, that the average premium of an equity investment over a fixed income

investment, over a period as long as 50 years, represents the investor required premium in today's and tomorrow's market.

Accordingly, we conclude that we can place little credence in the results of these methodologies.

c. Earnings/ Price Ratios

As noted above, it has been quite some time since we have been presented with an earnings/ price ratio analysis. We do find some conflict in theory between it and the DCF method. The DCF theory tells us that the investor is influenced by his expectation of appreciation in his investment, which is quantified by the growth in dividend element in the DCF formula. The earnings/ price ratio analysis suggests that we can determine investor's expectation without attempting to directly quantify the investor's appreciation expectation. This aside, it does seem that the earnings/ price ratio analysis has some value.

In this instance, Mr. Steslow's conclusion was an earnings requirement in the range of 12.5% to 13.5%. Since this range is somewhat broader and somewhat higher than our DCF indicated result, we are inclined [*216] toward a somewhat higher conclusion than we might reach, relying upon the DCF analysis alone.

We note that although the ALJ analyzed the evidence before him significantly differently than we have done, he arrived at a conclusion of 12.91%. This is toward the upper end of our DCF range and near the mid-point of our earnings/ price ratio conclusion. Accordingly, we shall adopt his conclusion of 12.91%.

F. Conclusion

Based upon the foregoing, our allowable rate of return determination in this proceedings is 11.14%, as illustrated in the following table:

Capital		Cost	Weighted
Structure	Ratios	Rates	Cost
	%	%	%
Debt	48.4	10.15	4.91
Preferred	14.2	9.89	1.40

Capital		Cost	Weighted
Structure	Ratios	Rates	Cost
	%	%	%
Equity	37.4	12.91	4.83
Total	100		11.14

VIII. RATE STRUCTURE

The Company has stated that the rates set forth in its Supplement No. 69 were designed to: (1) reflect, to the maximum extent practical, the cost of providing service; and (2) avoid any disruptive changes in the design of rates, which would unduly affect any customer or customer class.

A. Cost of Service

The OCA took issue with the Company's cost of service studies. The ALJ reported upon that dispute and recommended as [*217] follows:

The Company conducted its cost of service studies to allocate or directly assign plant investment and expenses in a manner which reflects each class' contribution to the incurrence of those costs. In preparing his cost of service studies, Mr. Harris employed the same methods and procedures involved in the functionalization, classification, and allocation of costs which have been reviewed and repeatedly approved by the Commission in prior Company rate proceedings. Those methods are also consistent with the standards set forth in the NARUC Electric Utility Cost Allocation Manual, and with generally accepted industry standards. The development of the Company's cost of service studies is described in detail in Mr. Harris' direct testimony (Penn Power Statement No. 7).

Only one party, the OCA, challenged the Company's cost of service studies in this proceeding. OCA witness Steven W. Ruback took issue with two aspects of the Company's studies: (1) the allocation of power supply costs, and (2) the classification of mass distribution costs. Each of these matters will be discussed briefly herein.

With respect to power supply costs, Penn Power has relied upon the average [*218] and excess method or allocating these costs among the rate classes. According to this method, the costs are apportioned partly on the basis of system average demand, and partly on the basis of the excess over the average demand of each of the rate classes. The average demand portion is allocated according to energy usage, while the excess demand portion is allocated according to the excess

of the individual class non-coincident peak demands over the average demand. Mr. Harris has pointed out that Penn Power has a rather flat load profile and relatively high system load factor due to the diversity of load on the system. According to him, the average and excess method recognizes this diversity and achieves an equitable distribution of the benefits of diversity among the customer classes. Furthermore, this method recognizes energy consumption through the average demand portion of production costs which, according to Mr. Harris, is consistent with the Company's use primarily of base load units as opposed to peaking units.

The OCA has advocated the use of the peak and average method in allocating power production costs. This method, like the average and excess method, allocates [*219] a portion of the costs on the basis of average demand. However, the remainder of the cost is allocated according to the average of twelve monthly coincident peak demands rather than the excess of non-coincident peak demands over average demand. This method, according to Mr. Ruback, is more reflective of cost causation than the average and excess demand method because capacity is designed to meet system demands and not the sum of class non-coincident peak demands. Mr. Ruback also contends that the use of twelve monthly peaks avoids allocation aberrations caused by non-representative contributions to a single peak by a particular class, and recognizes the effect of monthly peaks on capacity requirements relating to maintenance scheduling.

Company witness Harris has criticized the OCA's peak and average method because it does not properly allocate the benefits of diversity, and because it does not provide stable results in the face of shifting system peaks. Furthermore, Mr. Harris contends that the peak and average methods results in a double-counting of the average demand components, which adversely affects high load factor customers.

With regard to Penn Power's mass distribution [*220] costs, the Company has classified these items as both demand and customer-related. Mr. Harris has effected this classification by utilizing the so-called modified zero-intercept method, wherein it is assumed that the materials portion of the mass distribution costs is demand-related, and the labor portion of the costs is customer-related. According to Mr. Harris, this method recognizes as cost factors the geographical dispersion of customers, as well as class contribution to peak demand. As part of its justification for the use of this method, the Company refers to a study performed by Mr. Harris pursuant to a settlement stipulation in the rate proceeding at Docket No. R-842740. According to the Company, this study confirmed the propriety of the modified zero-intercept method and was reviewed and accepted by the Commission in the Company's most recent rate proceeding at Docket No. R-850267.

The OCA rejects the Company's modified zero-intercept method, contending that distribution systems are built to meet demand and should not be considered to contain a customer component. For this reason, Mr. Ruback classifies mass distribution costs as being solely demand-related, and includes [*221] no customer component in his classification and allocation of these costs.

It must be pointed out here that although the OCA has opposed the Company's methods concerning the allocation of power supply costs and the classification of mass distribution

system costs, it has not vigorously urged the total rejection of the Company's cost of service studies in favor of its own, due to the limited extent to which the Company has utilized its studies for the allocation of the revenue requirement among the customer classes (see below). For this reason the OCA has demonstrated a willingness to accept the results of the Company's study for this limited purpose, despite its disagreement regarding the issues just discussed.

As this Commission has repeatedly pointed out, the results of a class cost of service study are but one factor, albeit an important one, in establishing just and reasonable rates. As stated by the Commission in *Pa. P.U.C. v. Duquesne Light Co.*, Docket No. R-821945, p. 73 (Order entered January 28, 1983):

A cost of service study is one of the most subjective elements in any rate case. The methods used for classifying items of plant and expense between demand, customer [*222] and energy components are far from being an exact science. Cost of service studies are more accurately characterized as engineering art

This Commission has historically recognized the cost of service study for what it is: a useful tool for testing the reasonableness of the proposed allocation of the revenue requirement. Rarely, if ever, is revenue requirement allocated strictly on the basis of cost of service results.

In consideration of the foregoing, and of the fact that the results of the Company's cost of service studies have remained essentially unchallenged in this proceeding, I find no reason to specifically address either of the issues raised by the OCA as discussed above. Although there may be merit in the arguments put forth by both the Company and the OCA with respect to these issues, it is more appropriate in this case to judge the overall reasonableness of the Company's cost of service studies for ratemaking purposes, without particular regard for the specific issues concerning their development. Accordingly, it is recommended that the Company's class cost of service studies be found to be valid for the limited purpose for which they were used.

R.D., [*223] pp. 185-190.

No party has excepted to the ALJ's recommendation. We find that the cost of service studies are adequate for use in this proceeding. We would also comment with regard to the issue raised by the OCA pertaining to classification of a portion of distribution system costs as customer related, that we have, on numerous occasions, approved the classification of a portion of distribution as a customer cost, on both the zero intercept and other methodologies.

B. Class Revenue Allocation

The ALJ reported upon the Company's proposed revenue increase allocation to customer classes and recommended as follows:

Based upon the results of its cost of service studies, and upon the current and proposed rate structure, the Company has decided that a purely cost-of-service based allocation of the proposed revenue requirement would have a potentially disruptive impact on certain customer classes. For this reason the Company has proposed to distribute the increase on a relatively uniform basis, and in a manner which maintains as closely as possible the individual class rates of return as

indexed with the system average rate of return. This amounts to the following percentage increases [*224] for the customers [sic] classes.

Class	% Increase
Residential	
RS	51.4
WS	51.6
Total Resid.	51.4
Commercial/Industrial	
GS	51.6
GM	51.6
GP	47.8
GT 23 kv	50.9
GT 69 kv	50.7
GT 138 kv	54.4

A summary of the class rates of return at present and proposed rates is as follows:

	Before Increase		After Increase	
Rate	Return	Indexed Return	Return	Indexed Return
RS	4.19	0.97	12.17	1.03
GS	6.62	1.53	15.47	1.31
GM	5.62	1.30	13.11	1.11
GP	6.40	1.48	14.25	1.20
GT	3.00	0.69	9.58	0.81
St. Ltg.	8.06	1.87	18.64	1.58
Total				
Retail	4.32		11.83	

The Company's revenue collection scheme appears reasonable, and was not opposed by any party in this proceeding. I therefore recommend its adoption, subject to any necessary proportional adjustments in accordance with the actual amount of the increase allowed.

R.D., pp. 191-192.

No party has excepted to the ALJ's recommendation. We agree with the ALJ's conclusion. We note that the Company's proposal has the effect of moving all class rates of return closer to the system average rate of return and we agree with the ALJ that the Company's proposal is

reasonable. [*225] Since we have not granted the entirety of the Company's requested revenue increase, it will be necessary for the Company to proportionately scale back the proposed increase to the various customer classes, when filing its compliance tariff(s). In this regard the Company shall file as supporting documentation for its compliance tariff(s) a table in the form set forth immediately above and also indicate the percentage increases to each rate schedule, as is shown on the table preceding the one immediately above.

C. Intra-Tariff Rate Design

1. Energy Block Increases

The ALJ reports upon the matter of the Company's proposal regarding the individual tariff rate structure increases and recommends as follows:

The Company has proposed an intra-tariff rate design which allocates a greater portion of the revenue increase to the demand charges and earlier energy charge blocks, and a lesser amount of the increase to the tail blocks for each of the customer classes. This, according to the Company, is in keeping with its load factor philosophy of designing rates. This philosophy indicates that rates be designed in such a fashion as to promote the increased and efficient use of service, [*226] thus improving system load factor. It is the Company's position that lower tail block charges will encourage higher energy use resulting in improved customer load factors.

Such improved customer load factors will lead to an improvement in the overall system load factor which, according to the Company, will help defer the installation of additional generating capacity over time and the associated costs. Furthermore, the Company asserts that its tail block rates are important for competitive reasons, and that increasing these rates above the level proposed by the Company in this proceeding will result in the loss of incremental load to alternative fuels.

The OCA has strongly objected to the Company's intra-tariff rate design proposal, and has recommended instead that the increase be allocated on an even percentage basis to all rate blocks for each rate schedule. The OCA's objection applies particularly with respect to the rates for residential customers, and is made on several grounds.

First, it is the OCA's belief that the Company's rate design unfairly benefits large users while harming smaller ones. The OCA maintains that by placing most of the increase in the earlier energy [*227] blocks and little or none in the tail blocks, Penn Power is creating a situation in which the smaller customers must pay a disproportionate share of the Company's fixed costs, and are thereby subsidizing the larger customers. In this regard the OCA makes note of the fact that the last two energy blocks in the residential rate schedule are available only to those customers who are equipped with load meters. The OCA sees this as a further barrier to the participation in the benefits of the Company's rate design by the smaller users, since it is normally only the larger customers that qualify for load meters.

Secondly, the OCA does not believe the Company's rate design to be cost justified. OCA witness Ruback asserts that since most of the rate increase in this case is related to the addition of the Perry 1 unit, and since Perry's primary purpose is to provide low cost energy as opposed to peak

capacity, the rates should be designed to reflect this energy function. According to Mr. Ruback, this is accomplished by the OCA's across-the-board revenue allocation with respect to the energy blocks in each rate schedule.

A third reason for the OCA's rejection of the Company's rate design [*228] proposal is that such a proposal shifts the risk of sales declines from the Company to the ratepayers. It is Mr. Ruback's position that, under the Company's proposal, the customers are made to pay most of the fixing costs "up front" as it were, thus insulating the Company from the possibility of the underrecovery of fixed costs relating to the loss of sales in the tail blocks. Mr. Ruback believes that the Company's shareholders should bear a greater proportion of the risk of such underrecovery through a more even distribution of costs among the rate blocks, as it is proposed by the OCA.

Finally, the OCA rejects the Company's argument concerning the need to limit the increase to the tail block rates for competitive reasons. While agreeing that a greater increase in the tail block rates could have undesirable consequences for the Company concerning its competitive position relative to alternative fuels, the OCA does not believe this to be a valid reason for accepting the Company's rate design proposal. According to Mr. Ruback, the real reason for the threat to Penn Power's competitive position is to be found in the magnitude of the overall rate increase proposal, and the Company [*229] should not be allowed to mitigate the competitive effects of this proposal through an inequitable rate design.

The Company opposes the OCA's rate design position for several reasons. Besides maintaining that its own proposal is superior to that of the OCA due to its adherence to a load factor philosophy and its maintenance of the Company's competitive position with respect to alternative fuels, Penn Power believes the OCA's arguments against this proposal are flawed. Specifically, Penn Power rejects the OCA's assertions that the Company's rate design proposal unfairly shifts the risk of fixed cost recovery and penalizes customers with low energy usage. As the Company has stated in its reply brief (Penn Power Reply Brief, p.95).

This argument misrepresents the overall impact of the Company's rate design proposal. What the OCA continues to ignore is that all customers, including high energy users, must pass through the lower energy blocks and thus pay the same level of increase and contribution to fixed costs prior to reaching the tail blocks. Stated differently, the lower tail block rates will apply only to incremental sales and do not affect the obligation of any customer [*230] to first pay the higher charges in the earlier energy blocks.

Finally, the Company has pointed out that under its current and proposed rate designs, all Rate GT customers receive service under a single rate schedule which includes varying levels of discounts corresponding to the different voltage levels at which the Rate GT customers receive service. However, under the OCA's rate design proposal, Rate GT customers at different voltage levels would receive different increases, which would disrupt the Company's single rate schedule design for these customers. This would require the implementation of three separate rate schedules for Rate GT which, according to Mr. Pazak, represents a drastic change in rate design that would not be appropriate without a thorough analysis of the potential impact on the

customers and the need for future rate increases. Such an analysis has not been offered by the OCA.

Although there may be some validity in the OCA's equal percentage allocation of the revenue increase among the energy blocks for each rate schedule, the Company's rate design proposal is more justifiable from an economic standpoint. Regardless of the fact that the proposed increase [*231] is related primarily to Company investment in plant designed to produce low cost energy, such investment represents mostly fixed costs which should not be spread evenly among rate blocks, but should be allocated in such a way as to allow their timely recovery by the Company. In this regard the Company's intra-tariff revenue distribution seems most appropriate. Such a rate design is reflective of the decreasing nature of the fixed costs with increasing energy use, and will promote such increased usage, providing, as the Company has noted, a greater base from which to recover fixed costs.

Penn Power's rate design proposal appears to be particularly appropriate in view of the Company's load factor philosophy. Given the existing load factor design of Penn Power's rate schedules, the Company's proposed rate design will serve to promote not only increased energy use, but more efficient use of the Company's system. While it may be true that the Company's load factor design in its residential rate schedule prevents smaller users from taking service under the last two energy blocks as pointed out by the OCA, these blocks exist precisely for the purpose of encouraging greater efficiency [*232] among the consistently higher energy users, whose greater use renders such encouragement more critical in this regard. Such greater efficiency in the high energy users will promote a better system load factor which will benefit all customers. I therefore disagree with the OCA's believe that the smaller residential customers cannot benefit from the last two energy blocks in the residential rate schedule.

I do not concur with the OCA that the Company's rate design proposal will protect large users at the expense of smaller one, or that it is an attempt to shift the risk of fixed cost recovery from the Company to the ratepayers. As the Company has argued, all customers, whether they be high or low energy users must pass through the early energy blocks and pay the same level of contribution to the recovery of the fixed costs. The Company's rate design represents a reasonable approach to the recovery of fixed costs which adequately reflects cost causation, and I find no reason to sacrifice this sound approach for one which arbitrarily assigns a greater measure of risk to the Company in order to serve the notion that Penn Power should bear more of the risk as a matter of principle. [*233]

Finally, I agree with Penn Power that assigning a greater portion of the increase to the tail blocks than was proposed by the Company may be harmful to the Company's competitive position., The pricing of incremental load at noncompetitive rates may assure a decline in sales for the Company, and a consequent underrecovery of fixed costs, to the detriment of all customers. For this reason and those stated above, I recommend that the Company's rate design be found to be just, reasonable, and in the public interest, and I recommend the adoption of the Company's proposal, subject to any necessary proportional adjustments in accordance with the amount of revenue requirement actually allowed.

R.D., pp. 192-199.

The OCA has excepted to the ALJ's recommendation. The entirety of the OCA's exception is devoted to the subject of the Company's proposed increase to the energy blocks of the residential rate, where the existing rate for the initial energy block charge is approximately 300% of the rate for the terminal block. Additionally, the rates for the second and third energy blocks are approximately 240% and 200%, respectively, of the rate for the terminal block. Under the Company's [*234] proposal with unequal increases in the residential energy blocks, the decline of the rates will be further increased. While the Company has justified its proposal as an attempt to improve the system load factor, the OCA notes that Penn Power has one of the highest load factors of any electric utility in the Commonwealth. Additionally, we are not satisfied that tariff block pricing in order to improve the residential class load factor is efficacious. We also believe that the diurnal pattern of residential life is such that it is unlikely to be significantly influenced by energy pricing. Additionally, if the residential customer class has little opportunity to respond and change its usage of electricity, the Company's proposal becomes little more than an unwarranted punishment. Accordingly, we shall grant the OCA's exception.

We adopt the Company's proposed rate block increases with regard to all classes of service except those pertaining to residential services. With regard to the residential tariffs we hereby direct that the class increase be applied to each energy block on an equal percentage increase basis. 37👇

[*235]

2. PEPCO Credit Rider

The ALJ's report and recommendation on this subject, is as follows:

Penn Power's proposed rates reflect the sale of 28 MW of capacity to the Potomac Edison Power Company (PEPCO). On January 1, 1989, and June 1, 1989, the Company plans to make additional sales of capacity to PEPCO amounting to 14 MW and 21 MW respectively. The January 1 sale will result in the elimination of \$3,567,827 in revenue requirement from base rates, while the June 1 sale will cause a reduction of \$5,053,947 in base rates. The Company has proposed to implement these reductions in revenue requirement through the use of a PEPCO Credit Rider. This rider sets forth proposed reductions to each rate block in the Company's rate schedules corresponding to each level of sale to PEPCO. These reductions are designed to effect the overall reduction in revenue requirement associated with each sale.

While not opposed to the use of the PEPCO Credit Rider in principle, the OCA has taken issue with certain aspects of the Company's design of the rider. Specifically, the OCA objects to the fact that the rider reflects no credit in the tail blocks of Rates RS and GT. The OCA argues that since [*236] company witness Pazak has characterized the capacity sales to PEPCO as representing a "slice of the system" (Tr. 364), such sales would include costs associated with all of the Company's generating units, and should thus be reflected in all rate blocks designed to recover these costs. Furthermore, the OCA asserts that if its intra-tariff rate design proposal to increase the tail block rates is adopted, then the PEPCO Credit Rider should provide for credits

in the tail blocks of these rates. Accordingly, the OCA proposed that the rider be modified to include such credits.

Penn Power rejects the proposal of the OCA stating that the Company's treatment of the Rate RS and Rate GT tail block is fully cost justified. As expressed by Mr. Pazak in his rebuttal testimony (Penn Power Statement No. 1-R, p. 13):

The Company believes that no increase is appropriate in the tail block of Rate RS and, therefore, no credit is appropriate for the PEPCO sales. This is consistent and fair since PEPCO sales are based on average embedded costs and the Company is using the tail block of Rate RS to sell additional kilowatt-hours at incremental Kwh costs. Only a small increase is proposed by the Company [*237] in the last block of Rate GT to achieve the cost of service supported charge of 1.76 per Kwh. No PEPCO credit is necessary since this rate is fully cost justified. In any event, adding a credit to these tail blocks would contribute to the reduction in energy revenues and under-recovery of fixed costs.

The Company, therefore, sees no reason to modify its proposed PEPCO Credit Rider.

Both the Company and OCA agree that if the OCA proposal to extend recovery of the revenue increase into the tail blocks is accepted, then it would be appropriate to likewise extend the PEPCO Credit Rider into the tail blocks. OCA Main Brief, pp. VIII-17-VIII-18; Tr. 1117.

As the OCA revenue recovery proposal has not been recommended, it is further recommended that the OCA proposal regarding extending the PEPCO credit to the tail blocks not be adopted. R.D., pp. 199-201.

No party has excepted to the ALJ's recommendation. However, as noted by the ALJ, since we have adopted the OCA's proposal to extend the increase to the terminal block of the residential rate schedule, it will be necessary for the Company to appropriately modify the PEPCO rider to make it applicable to the terminal blocks [*238] of the residential tariffs. 38. The Company is directed to accomplish such a modification in conjunction with its compliance tariff filing.

D. Miscellaneous Tariff Changes

Penn Power has proposed a number of changes to various tariff rules and provisions. The Company has itemized and described the changes in its Main Brief as follows:

- a. In the Company's rate proceeding at Docket No. R-850267, the word "customer" , on the second line of Rule 1, was changed to "applicant." The Company is proposing similar changes throughout the remaining lines of this Rule for purposes of consistency and clarification.
- b. In Rule 13, the following additional sentence is proposed: "In addition, the Company shall not be liable for implied warranties of merchantability [sic] and fitness for particular purpose except and unless required by law as being excludible by contract."
- c. Minor modifications to Item 2 in Rule 24 are also proposed for purposes of clarification.
- D. In Rule 25, Item F, the reference to "Rule 26" has been corrected and changed to "Rule 24".

e. The Company [*239] is proposing that the late payment charge for industrial and commercial customers be increased from 1.35% to 2%, in order to bring this charge in line with the practice of most other Pennsylvania utilities.

f. Finally, the word "wholehouse" has been added to Provision (b) under the Company's Optional Controlled Service Rider. This change is needed to limit the scope of this provision to wholehouse load control devices and exclude the use of individual appliance load control devices.

M.B., pp. 271-272.

No party opposed these proposed changes. The ALJ recommended that they be approved and no party has excepted to that recommendation. Having reviewed these minor changes and finding them to be reasonable, they are, hereby, approved.

IX. PHASE-IN PROPOSAL

The Company has voluntarily proposed to phase-in the increase granted in this proceeding, over a four-year period, by delaying the billing and collection of a portion of the increase. The Company stated that its phase-in proposal was designed to mitigate the impact on the ratepayers and the economy of its service area. The plan, as described in its Main Brief, is as follows:

The Company's proposed phase-in will be [*240] implemented in four steps, with revenue recovery deferred during the first two years to be collected over a second two-year period. A carrying charge rate of 6% will be applied to the deferred revenues in order to compensate the Company for the lost time value of money resulting from the proposed revenue deferrals (PPC St. 1, p. 27). When offset in future years by credits associated with the additional sales of power to PEPCO in January and June 1989, as more fully discussed below, the Company's proposal will result in a total increase over the four-year period of approximately 46.6%, or an average of 17.2% on an annual basis (PPC Ex. 1-A). 77 As explained by Mr. Pazak, the Company's willingness to phase-in the increase over four years is based upon the granting of the full amount requested (PPC St. 1, p. 28).

Under the Company's proposal, revenue would be deferred through application of a Deferred Revenue Collection Rider to each rate schedule (PPC St. 1, p. 27). At the end of the case, the total rate increase allowed by the Company would be filed together with adjustment factors for each rate block of each rate to reflect the phase-in. Assuming approval of a four-year phase-in, [*241] the adjustment factors would be used to compute customers' bills during that four-year period. The full increase would be billed during the third year. (PPC St. 1, p. 28).

The Company will compute each month for each rate schedule the difference between the amount the customer would have been billed under the approved tariff rate, including the appropriate interest, and the amount actually billed by application of the rate adjustment factor. During the first two years of the plan, this difference will be recorded as deferred revenue and will be carried on the balance sheet in FERC Account No. 186 as a deferred debit. A separate entry will be set up for each rate classification so the unrecovered amount can be collected from the appropriate rate classification (PPC St. 1, pp. 28-29).

Collection of the unrecovered revenue will begin in the third year with application of the specific deferred revenue factors to each rate block. The collection of this deferred revenue will continue for each rate class until all the revenue in Account 186 for that class has been collected including the appropriate interest (PPC St. 1, p. 29).

The Company will precisely track the recovery of [*242] revenue from each rate class and cease the application of the recovery factors when recovery is complete. Due to sales differences, the precise recovery period will vary from class to class and may occur in more or less than four years. In addition, the Company proposed to review the recovery factors annually and to adjust the factors, as necessary, to permit recovery over a four-year period (PPC St. 1, p. 29).

M.B., pp. 272-275.

The ALJ explored this proposal and recommended modification to the Company's proposal. We shall set forth this discussion in full.

The OTS has objected to the Company's phase-in plan, stating that no phase-in would be necessary if the OTS recommended increase were allowed. If a greater increase is granted the Company, the OTS would agree to a phase-in plan involving no more than two years, depending upon the size of the increase. In any event, the OTS believes that under no circumstances [*243] should the Company be permitted to collect carrying charges on the deferred revenue, and gives several reasons for this. OTS Main Brief, pp. 68-71.

First, the OTS contends that customers should not have to pay carrying charges on deferred revenues related to what the OTS believes to be unnecessary expenses. Such expenses, according to the OTS, are the result of excess capacity represented by the addition of the Perry 1, unit. Second, the OTS asserts that the Company has given no financial justification for the need to impose carrying charges. Although the Company has claimed that the denial of carrying charges would be recorded as a reduction to plant-in-service, the OTS sees this as being only a temporary write-off for financial reporting purposes, which would be restored during the course of the phase-in. Furthermore, the OTS claims that the Financial Accounting Standards Board Statement No. 92 (FASB No. 92) on which the Company has based its accounting position in this matter has no authority with regard to the Commission's power concerning phase-in carrying charges. A third reason for the OTS recommendation to deny carrying charges is its opinion that such carrying charges [*244] would contribute to the "rate shock" problem which the Company is attempting to avoid in the first place. Finally, the OTS cites two other cases (Pa. P.U.C. v. Pennsylvania Power & Light Company, Docket NO. R-842561 and Pa. P.U.C. v. Philadelphia Electric Company, Docket No. R-850152) in which the utility companies involved proposed phase-in plans without requesting to recover carrying charges, suggesting that Penn Power likewise should not have made such a request.

The Company opposes the OTS position as presented above. With respect to the OTS argument concerning unnecessary expense related to the Perry 1 unit, the Company claims that the record in this case demonstrates that Perry 1 does not constitute excess capacity. Also, the Company points out that the carrying charges would only be applied to that amount of the increase finally allowed by the Commission. With regard to the OTS position concerning the financial impact of

denying carrying charges, the Company maintains that the write-offs of deferred revenues would not be temporary, but would result in a permanent economic loss to the Company. Concerning the OTS argument that carrying charges would contribute to rate [*245] shock, Penn Power has stated that the imposition of carrying charges is designed to make the Company whole for the costs it incurs in reducing rate shock to ratepayers. Furthermore, the Company asserts that OTS witness Weakly, during cross-examination, recognized that ratepayers would fare better under phase-in with carrying charges than if the Company-proposed increase or the OTS-recommended increase were implemented all at once. Finally, the Company dismisses as irrelevant the cases cited by the OTS involving utility companies that proposed phase-in plans without requesting recovery of carrying charges.

It should be noted here that the OCA has contended that the allowance of carrying charges constitutes an additional reason for adopting a lower return on equity for Penn Power. However, the Company opposes this position, stating that carrying charges are completely unrelated to the equity return allowance. The Company also points out that such a position is inconsistent with the OCA's own assertion that other rate issues should be addressed independently of the phase-in proposal. Which leads to the final point that, in essence, OCA has taken no position on the phase-in proposal. [*246] However, OCA has pointed out the phase-in proposal benefits the Company by virtually assuring recovery of the level of revenue allowed in this proceeding. OCA Main Brief, pp. VII-1-VII-2. Also see Tr. 495-508.

It is appropriate to note at this juncture that Penn Power offered the testimony of Mr. Benjamin A. McKnight in rebuttal to the proposals to make disallowances for Perry 1 imprudency, for Perry 1 "early-window" expenses, for Perry 1 common facilities, for excess capacity and to deny any interest on deferred revenues under the Company's phase-in proposal. Mr. McKnight is well qualified to offer an expert opinion on these issues as he is a CPA and partner with Arthur Andersen & Co., in the position of Accounting and Audit Coordinator in the firm's Utilities and Telecommunications Industries Program. His responsibilities include monitoring all activities of the Financial Accounting Standards Board (FASB) which concern regulated enterprises. PP St. 18-R, pp. 1-3. Tr. 1351-1355.

In his testimony dealing specifically with the phase-in proposal he described the financial accounting implications as follows:

A. SFAS No. 92 deals with accounting for phase-in plans.

Specifically, [*247] paragraphs 21 through 24 deal with a phase-in plan where no return on amounts deferred under the plan is allowed. Such a disallowance of return on investment for the deferred amount is considered to be an indirect disallowance.

Q. What is the appropriate accounting treatment for such an indirect disallowance?

A. Pursuant to paragraph 22 of SFAS No. 92, the amount recoverable under the phase-in plan would be discounted to reflect its present value, using a discount rate equal to Penn Power's weighted average overall cost of capital. This discounted amount would be compared to the estimated receivables that would periodically be recorded on the balance sheet each year of the

phase-in plan. The excess of the estimated receivables over the discounted present value thereof would be recognized as a loss currently.

Q. What are the accounting implications if the Company's request for an interest rate of 6% applied to the deferred amounts is granted?

A. As noted above, paragraph 22 of SFAS No. 92 requires that the amount to be recovered are to be discounted using the utility's weighted average overall cost of capital. If the overall cost of capital exceeds the 6% interest rate [*248] requested, the Company would recognize a loss. The accounting would be similar to that described in my answer to question 24, above. However, provision for a 6% carrying charge rate would at least serve to mitigate the loss.

PP. St. 18-R, pp. 12-13.

On cross-examination, Mr. McKnight was asked whether, under the phase-in proposal, if no carrying charge was allowed and a loss recognized, a loss would be stated in the Company's financial statements. He stated that the loss should be reflected in the income statement. If significant enough, the loss would be the subject of a note. He agreed that the loss would result in a reduction to plant in service which in turn would reduce depreciation expense. However, he disagreed in a full recovery of its expenses by the Company.

Q. I'm asking you essentially that at the end of the phase-in period whether the company's financial position with respect to, say, the plant and the retained earnings, would be the same whether the Commission allowed carrying charge or not.

A. No, that wouldn't be correct because presumable if all the -- if a return had been provided and capitalized on the costs deferred in connection with the phase-in [*249] plan and they were recovered in connection with the phase-in plan, it would be additional shareholders' equity.

The fact that there is this difference in shareholders' equity, shareholders' equity is a lower amount, just substantiates the fact that an economic loss has been incurred.

Q. But isn't that offset some by the depreciation expense?

A. Depreciation expense is just sort of a timing thing. That depreciation expense is written off on the front end, but the fact remains economically that that depreciation expense did not get and will not be recovered in rates, so a loss has occurred.

Tr. 1350.

Thus Penn Power, in proposing that 6% interest be added to deferred revenues rather than its embedded cost of capital, is accepting a loss, at least for accounting purposes. However, the point made by OCA is certainly valid. Under the Company's proposal it will be recovering all of the revenue level permitted by this Commission. No provision is made to the best of my knowledge to provide for any deviation in the sales level provided for in the future test year projection. Thus the risk of a reduction in sales volume is passed to the Company's ratepayers. If this conclusion [*250] is in error, the Company should so state in its exceptions and provide specific record citations.

It is inconceivable to me that an increase of the magnitude contemplated here would fail to result in a lower sales level than would have occurred under present rates. It is axiomatic that increases in price lessen demand. This very problem is raised in the background notes (Appendix C) to FASB Statement No. 92, alluded to in a dissent, but not dealt with in regard to any resolution.

It is recommended that the Company be directed to modify its phase-in proposal to base its revenue recovery on the future test year sales projections. In the event sales on a rate class basis should fall below the projected level the resulting revenue deficiency would not be deferred for later collection nor would the deficiency be added to the balance which would be used for computing the 6% interest. The result would be to have the normal business risk of maintaining sales levels continue to be in the Company as is usually the case. Additionally, should sales levels increase above the established base sales level, the additional revenues should be applied to decrease the deferred balances and associate [*251] interest charges. Such a provision would serve to further soften the "rate shock" effect. This recommendation assumes adoption of the phase-in proposal. The Company's willingness to undergo a phase-in will, I am sure, be influenced by the revenue level ultimately allowed.

From a rate base design perspective, the Company's Deferred Revenue Collection Rider is a valid mechanism for implementing the Company's proposed phase-in plan. No party has opposed the specific design of this rider, although it must be noted that such a design is necessarily based upon the Company's intra-tariff rate design proposal for the requested increase without a phase-in, as described above. As such, it would not be directly adaptable to another rate design scheme such as that proposed by the OCA. However, given the recommended acceptance of the Company's rate design proposal apart from the phase-in, it is recommended that the Deferred Revenue Collection Rider be adopted as proposed but as modified above and subject to any proportional adjustments necessary in light of the amount of the increase and the specific terms of the phase-in allowed.

R.D., pp. 205-212.

The Company has excepted to [*252] the ALJ's proposed modifications to its proposal (Co. Ex., pp. 15-18). The OTS has opposed the Company's exception.

The substance of the Company's exception is as follows:

The ALJ has recommended that the Company's proposal to phase-in the increase over four years, with carrying charges at 6%, be implemented with the following three modifications: (1) revenue recovery under the plan should be based on future test year sales projections; (2) if sales in a given year for a particular rate class fell below the future test year projections, the revenue deficiency should not be deferred for later recovery or used to calculate a carrying charge; and (3) if sales exceed the projections, the additional revenues should be used to reduce the balance of deferred revenues and associated carrying charges (R.D., pp. 210-212). The ALJ's recommendation reflects a misunderstanding of the Company's proposed phase-in. Specifically, the first two suggested modifications are already incorporated in the Company's plan. The third modification, on the other hand, is clearly unreasonable and should be rejected.

* * * * *

As the above example demonstrates, the first two modifications are proposed [*253] by the ALJ are already reflected in the Company's proposed phase-in plan. Revenue recovery is, in fact, established on the basis of future test year sales levels since it is these projections which will be used to calculate the specific rates that would be charged both with and without the phase-in. If sales decline below the projected levels, the revenue deficiency will not be deferred or used in the calculation of carrying charges. Rather, that deficiency will be absorbed by the Company as is normally the case after any rate proceeding.

Only the ALJ's third modification, which would reduce deferred revenues to the extent that sales exceed future test year projections, is not reflected in the Company's phase-in plan. As noted above, under the Company's proposal, deferred revenues would increase if actual sales are greater than the projections. The ALJ's recommended modification would effectively penalize the Company for voluntarily electing to phase-in the increase rather than implementing it immediately. As shown in Scenario 4 in Appendix A, by reducing the balance of deferred revenues, the ALJ would reduce the total amount of revenues collected under the phase-in (column [*254] D) below the level that the Company would otherwise receive if the rate increase were implemented in full at the end of this case (column B). In other words, this modification would disallow a portion of the rate increase granted in this proceeding. Moreover, under the ALJ's proposal, the Company would be required to absorb the risk of declining sales levels but would not receive any of the benefits if sales increase above the future test year projections. Such a result is obviously inequitable and should, therefore, not be adopted by the Commission.

Co. Exc., pp. 15-18

The OTS' position is that the Company's position is totally unacceptable. We do not agree. Under the Company's proposal we do not see that it faces either more or less risk with regard to the collection of its revenue requirement than if the entirety of the increase went into effect immediately. We note, in this regard, that no party took issue in any way with the Company's sales estimates, which is, after all, the critical factor with regard to the collection of its revenue requirement. We do find merit to the Company's exception and no need to adopt the ALJ's proposed third modification to the Company's [*255] exception and approve the phase-in proposal as proposed by the Company.

X. CONCLUSION

We have concluded that the Pennsylvania Power Company is entitled to an opportunity to earn income available for return of \$72,855,000, based upon its Pennsylvania jurisdictional operations. The Pennsylvania Power Company is authorized to establish intrastate rates designed to produce \$240,010,000 in annual electric operating revenues. The increase in annual operating revenues herein authorized is \$67,117,000 with said increase to be phased in over a four-year period under the plan set forth within this Opinion and Order; THEREFORE,

IT IS ORDERED:

1. That the Pennsylvania Power Company shall not place into effect the rates contained in Supplement No. 69 to its Tariff Electric-Pa. P.U.C. No. 33, the same having been found to be unjust, unreasonable, and therefore, unlawful.
2. That the Pennsylvania Power Company is, hereby, directed to file tariff(s) or tariff supplement(s) containing rates, rules, and regulations, consistent with our findings herein, designed to produce no more than \$240,010,000 in Pennsylvania jurisdictional annual operating revenues, exclusive of revenues normally derived [*256] from the State Tax Adjustment Surcharge.
3. That the \$67,117,000 annual operating revenue increase authorized herein shall be phased-in over a four year period.
4. That the tariff(s) or tariff supplement(s) to be filed may be filed on less than statutory notice and, pursuant to the provisions of 52 Pa. Code §§ 53.31 and 53.101, may be filed to be effective for service on and after the date of entry of this Opinion and Order.
5. That in support of such tariff(s) or tariff supplement(s) there shall accompany such filing(s) a proof of revenue, in the form and manner customarily filed in support of compliance tariffs and, additionally, calculations supporting the roll-in of the State Tax Adjustment Surcharge as described in the body of this Opinion and Order.
6. That the Pennsylvania Power Company shall comply with all other directives contained in the body of this Opinion and Order, which are not subject of an individual Ordering Paragraph, as fully as if they were the subject of a specific Ordering Paragraph.
7. That, except to the extent granted herein, specifically or by implication, the exceptions of all parties to the Recommended Decision of the Administrative Law [*257] Judge are, hereby, denied.
8. That upon Commission acceptance and approval of the tariff(s) or tariff supplement(s), directed to be filed herein, the Commission investigation at this docket shall be terminated and the file marked closed.

TABLE I

PENNSYLVANIA POWER COMPANY

INCOME SUMMARY

(000)

	Pro Forma	Commission	Adjusted	Commission	Total
	Present	Adjustments	Present	Increase	Revenue
	Rates		Rates		
Operating Revenue	\$176,046	(\$3,153)	\$172,893	\$67,117	\$240,010
Deductions					
O&M Expenses	+ \$112,948	(\$9,342)	\$103,606		\$103,606
Depreciation	\$26,937	(\$1,221)	\$25,716		\$25,716
Taxes					
State	(\$1,963)	\$909	(\$1,054)	\$4,589	\$3,535
Federal	(\$9,424)	(\$5,363)	(\$14,787)	\$20,803	\$6,016
Other	\$11,612	\$2	\$11,614	\$1,342	\$12,956
Net Deferred *⬆️	\$6,972	\$8,353	\$15,325		\$15,325

PENNSYLVANIA POWER COMPANY

INCOME SUMMARY

(000)

	Pro Forma	Commission	Adjusted	Commission	Total
	Present	Adjustments	Present	Increase	Revenue
	Rates		Rates		
Total Deductions	\$147,082	(\$6,662)	\$140,420	\$26,734	\$167,154
Income for Return	\$28,964	\$3,509	\$32,473	\$40,382	\$72,855
Rate Base	\$694,449	(\$40,454)	\$653,995		
Commission Return			11.14%		
[*258]					

Commission Return

	Capital		Weighted
	Structure	Cost	Cost
Long-Term Debt	48.40%	10.15%	4.91%
Short-Term Debt	0.00%	0.00%	0.00%
Preferred Stock	14.20%	9.89%	1.40%
Common Equity	37.40%	12.91%	4.83%
Total	100.00%		11.14%

TABLE II

PENNSYLVANIA POWER COMPANY

SUMMARY OF ADJUSTMENTS

(000)

	Rate			Taxes-
	Base	Revenue	Expense	Depreciation
				Other
				2.000%
Perry Common Plant	(\$36,412)			(\$1,221)
Deferred Tax Balances	(\$3,552)			
Coal Inventory	(\$318)			
Forfeited Discounts		\$120		\$2
Uncollectible Accounts			(\$600)	
CAPCO Cancellation Costs			(\$1,495)	
Spent Fuel Disposal Expense	(\$172)		(\$1,472)	
Rate Case Expense			(\$300)	
EEI Dues and Advertising			(\$51)	
Perry I Early Window			(\$5,180)	

PENNSYLVANIA POWER COMPANY

SUMMARY OF ADJUSTMENTS

(000)

	Rate				Taxes-
	Base	Revenue	Expense	Depreciation	Other
					2.000%
Capitalized Taxes					
Credits for Capacity Sales		(\$3,273)	(\$244)		
ITC Deferral					
ITC Amortization					
Interest Expense *📌					
	(\$40,454)	(\$3,153)	(\$9,342)	(\$1,221)	\$2
	State	Federal		Net	
	Tax	Tax		Deferred	Return
	6.97674%	34.00%		Tax	

PENNSYLVANIA POWER COMPANY

SUMMARY OF ADJUSTMENTS

(000)

	Rate			Taxes-
	Base	Revenue	Expense	Depreciation
				Other
				2.000%
Perry Common Plan	\$198	\$900		(\$758)
Deferred Tax Balances				\$881
Coal Inventory				
Forfeited Discounts	\$8	\$37		\$73
Uncollectible Accounts	\$42	\$190		\$368
CAPCO Cancellation Costs	\$104	\$473		\$918
Spent Fuel Disposal Expense	\$103	\$465		\$172
Rate Case Expense	\$21	\$95		\$732
EEI Dues and Advertising	\$4	\$16		\$184
Perry I Early Window	\$361	\$1,638		\$31
				\$3,181

PENNSYLVANIA POWER COMPANY

SUMMARY OF ADJUSTMENTS

(000)

	Rate			Taxes-	
	Base	Revenue	Expense	Depreciation	Other
					2.000%
Capitalized Taxes		(\$115)			\$115
Credits for Capacity Sales	(\$211)	(\$958)			(\$1,860)
ITC Deferral		(\$9,367)		\$9,367	
ITC Amortization				(\$428)	\$428
Interest Expense	\$279	\$1,263			(\$1,542)
	\$909	(\$5,363)		\$8,353	\$3,509

[*259]

Footnotes

1

Ohio Edison, a registered holding company under the Public Utility Holding Act of 1935, provides electric service throughout a 7,500 square mile area in central and northeastern Ohio.

2

Other members of CAPCO include Ohio Edison, Duquesne Light Company, Cleveland Electric Illuminating Company, and Toledo Edison Company. In the aggregate, the CAPCO companies service an area of 14,000 square miles in western Pennsylvania and northern and central Ohio with a population of approximately 7 million.

*¶

Down from 25 Mw due to change in agreement. Source: PP St. 1, Schedule 2, Table 3 with the revision noted.

**¶

Includes 28 Mw of sales to non-associated utilities. Source: PP St. 1, Schedule 2, Table 4, annotated and revised.

3¶

The OTS is proposing a rate base reduction of \$3,552,264. The OCA proposed a reduction of \$2.18 million.

4¶

It appears that the OTS' and the OCA's positions expressed in their respective Main Briefs are moderated from the positions espoused during the hearings.

5¶

The \$2.18 million adjustment proposed by the OCA is substantially less than an 80% level.

6¶

In saying this we recognize that the Tax Reform Act of 1986 is requiring the capitalization of items which might formerly have been expensed.

7¶

The OTS has not set forth its reasoning in a syllogistic form and it seems to us that several pieces in a line of reasoning have been omitted.

8¶

As was the situation with the income tax liability associated with Contributions in Aid of Construction, this amounts to a prepaid tax item.

9¶

We also note that we approved the concept of such a rate base claim in our Opinion and Order in the proceeding at Pa. P.U.C. v. Duquesne Light Company, R-860378 (March 10, 1987).

10¶

In its Exceptions, the OTS characterized this statement as second hand information, unsupported by other evidence. Since the OTS did not have this statement stricken, we are entitled to consider it for what it is worth. We note that we frequently must rely on evidence or testimony inherently less reliable than this statement, in resolving issues in rate proceedings.

11

We also point out that any reserve account which receives rate base recognition was created over a term of years prior to the test period.

12

This is a deferred tax asset account as distinguished from the deferred tax liability account used to reflect the normalization of deferred taxes, as a result of accelerated depreciation. The deferred tax asset account can also be described as one reflecting prepaid taxes. This term may be more comfortable to those not totally familiar with the intricacies of accounting and its terminology.

13

The amount involved is \$43,049.

14

The latter method employs shorter depreciation lives and, hence, creates greater income tax related depreciation expense, lowering current income taxes below the level which they would be utilizing book lives. We shall refer to this as the ADR Benefit.

15

Since this amortization of this portion of the deferred tax reserve will be replaced in the relatively near future by an increased revenue requirement to pay the deferred, increased income tax expense, the benefit is a temporary benefit, which would be more properly represented by the result of a present value calculation, rather than the principal amount of \$1.4 million.

16

Thus, OTS proposal is akin to spending your "rainy day fund" because you are assured that it won't be needed for a few years, only to suffer the discomfort of saving it up again.

17

The OCA has not taken a position on this subject.

18

Approved by Commission Order entered September 29, 1986 at those same dockets.

19

The term "unprotected" indicates that TRA86 does not specify the manner in which the accruals in excess of the current corporate tax rate, are to be amortized. Accordingly, a decision regarding the manner of amortization is solely a regulatory and accounting decision.

20

The OCA has taken no position on this issue.

21

We should also comment that testimony found in part to be devoid of a factual basis, casts grave doubt upon the value if not reliability of the witness' remaining testimony.

22

We hasten to add that we do not intend to single out OTS witnesses as the sole offenders in this regard. All parties to past proceedings have, at times, presented testimony of a quality which is unworthy of the parties.

23

The OTS appears to be referring to the termination of the creation of new credits, rather than the abolition of previously accrued credits, which may still be carried forward.

24

The OCA did not take any position on this issue.

25

There may have been differences, in some instances, between actual taxes and ratemaking taxes. In these instances, the criterion was the level of investment tax credits which can be utilized to offset the tax allowances for ratemaking purposes.

26

The STAS clause will be retained and set at zero.

27

Dr. Marcus set forth the list in his Schedule MM-10.

28

We have, in several cases, recognized the periodicity of dividends and adjusted the dividend yield by one-half of the growth rate. Cited by the Company are: Pa. P.U.C. v. Western Pa. Water Co., R-842621 (January 28, 1985); Pa. P.U.C. v. Riverton Cons. Water Co., R-842675, (March 21, 1985); and Pa. P.U.C. v. Phila. Sub. Water Co., R-842592 (December 10, 1984).

29

IBES does not forecast dividend growth rates.

30

Similar data for Ohio Edison is an IBES growth rate of 1.55%, and 10 year earnings and dividend growth rates of 2.5% and 1.5%, respectively.

31

With regard to Mr. Moul's additional 50 basis points added for the additional risk associated with Penn Power's lower bond rating, we note that in his Exhibit 4A, Schedule 8, page 5, Mr. Moul displays a 12 month average yield for Penn Power only 7 basis points above the barometer group average of 9.72%, or 9.79%,. Similarly the June 1987 premium for Penn Power was only 2 basis points above the barometer group average of 10.14%, or 10.16%.

32

Calculated for the years 1928-1985.

33

Beta is a measure of the volatility of the return on an individual security relative to a market as a whole. The theory being that a beta value less than one is considered to be a defensive security and less risky, and, correspondingly, the less the cost of capital, all else being equal.

34

In this instance the beta for Mr. Steslow's barometer group of .75 is identical to that of Ohio Edison.

35

By this comment we assume that Mr. Steslow is acknowledging that when information regarding a new issue is known in advance, that fact has already been reflected in the market price of the stock.

36

Mr. Steslow proposed an adjustment to the dividend yield to account for market pressure and the cost of flotation. We have routinely rejected such proposals. Such proposals have been universally opposed by the OCA and generally opposed by the Staff. We have never been satisfied that such an allowance is necessary, although we do recognize that market pressure and flotation costs exist. We have never been persuaded that the market does not already reflect investors' expectations with regard to such costs and that a separate allowance is necessary. We have not been satisfied here that such a separate and distinct allowance is necessary. We should also note that we have never led investors to expect such an allowance. Accordingly, we make no specific provision for market pressure and flotation in our allowance in this proceeding. Additionally, we reject Mr. Moul's provision of a 25 basis point allowance to account for the additional risk associated with Penn Power's lower common equity ratio.

37

This also applies to the special provision of Rate Schedule GS applicable to Volunteer Fire Companies and Senior Citizen Centers, which shall continue to mirror Rate Schedule RS.

38

This includes the special Volunteer Fire Company and Senior Citizen Center provision of the GS Schedule.

77

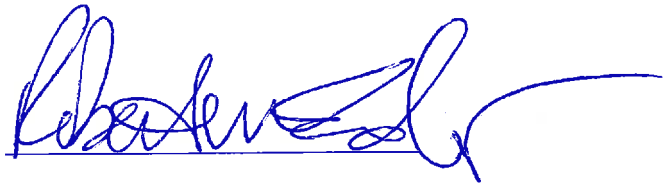
During the discovery process, two errors were detected in the numerical depiction of the Company's proposed phase-in plan as originally set forth in Mr. Pazak's direct testimony (Tr. 447-480). The figures referenced above reflect the correction of these errors.

**AFFIRMATION
OF
ROBERT M. ENDRIS,
FIRSTENERGY CORPORATION**

I, Robert M. Endris, do affirm as follows:

1. My name is Robert M. Endris. I serve as an Attorney at FirstEnergy Corporation (“FirstEnergy”); and
2. I attest that the information identified in FirstEnergy’s Responses to Complainants Verizon Pennsylvania LLC and Verizon North LLC’s First Set of Interrogatories was gathered under my supervision.

Executed on January 20, 2020



Robert M. Endris
Attorney
FirstEnergy Corporation

CERTIFICATE OF SERVICE

I, Timothy A. Doughty, hereby certify that on this 20th day of January 2020, a true and authorized copy of Metropolitan Edison Company, Pennsylvania Electric Company, and Penn Power Company's Responses to the Complainants' First Set of Interrogatories was served on the parties listed below via electronic mail and was filed with the Commission via ECFS.

Marlene J. Dortch, Secretary
Federal Communications Commission
Office of the Secretary
445 12th Street SW
Washington, DC 20554
ecfs@fcc.gov
(By ECFS Only)

Rosemary McEnery
Federal Communications Commission
Enforcement Bureau
445 12th Street SW
Washington, DC 20554
Rosemary.McEnery@fcc.gov

Anthony DeLaurentis
Federal Communications Commission
Enforcement Bureau
445 12th Street SW
Washington, DC 20554
Anthony.DeLaurentis@fcc.gov

Curtis L. Groves
Verizon
1300 I Street, NW
Suite 500 East
Washington, DC 20005
Curtis.groves@verizon.com

Christopher S. Huther
Wiley Rein LLP
1776 K Street, NW
Washington, DC 20006
chuther@wileyrein.com

Claire J. Evans
Wiley Rein LLP
1776 K Street, NW
Washington, DC 20006
cevans@wileyrein.com

/s/ _____
Timothy A. Doughty