

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY
COMMISSION

v.

PENNSYLVANIA ELECTRIC COMPANY :

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:

DOCKET NO. R-2014-2428743

DIRECT TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

VOLUME 1

NOVEMBER 24, 2014

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ATTACHMENTS

RCS-1, Background and Qualifications

EXHIBITS:

LA-ME-1, Schedules showing Revenue Requirement, Rate Base, Net Operating Income and Adjustments for Metropolitan Edison Company

LA-PN-1, Schedules showing Revenue Requirement, Rate Base, Net Operating Income and Adjustments for the Pennsylvania Electric Company

LA-PP-1, Schedules showing Revenue Requirement, Rate Base, Net Operating Income and Adjustments for the Pennsylvania Power Company

LA-WP-1, Schedules showing Revenue Requirement, Rate Base, Net Operating Income and Adjustments for the West Penn Power Company

LA-2, Selected Non-Confidential Documents Referenced in the Testimony and Exhibits LA-ME-1, LA-PN-1, LA-PP-1 and LA-WP-1

LA-3, Selected Confidential FirstEnergy Responses to Interrogatory Requests and Other Documents Referenced in the Testimony and Exhibits LA-ME-1, LA-PN-1, LA-PP-1 and LA-WP-1

Note: These Exhibits are contained in Volume 2 (non-proprietary) and Volume 3 (proprietary) of Mr. Smith's Direct Testimony for each individual electric distribution company.

1 **I. STATEMENT OF QUALIFICATIONS**

2 **Q. Please state your name, position and business address.**

3 A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates,
4 PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

5
6 **Q. Please describe Larkin & Associates.**

7 A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting
8 firm. The firm performs independent regulatory consulting primarily for public
9 service/utility commission staffs and consumer interest groups (public counsels,
10 public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates
11 has extensive experience in the utility regulatory field as expert witnesses in over
12 600 regulatory proceedings including numerous telephone, water and sewer, gas, and
13 electric matters.

14
15 **Q. Mr. Smith, please summarize your educational background.**

16 A. I received a Bachelor of Science degree in Business Administration (Accounting
17 Major) with distinction from the University of Michigan - Dearborn, in April 1979.
18 I passed all parts of the Certified Public Accountant ("C.P.A.") examination in my
19 first sitting in 1979, received my CPA license in 1981, and received a certified
20 financial planning certificate in 1983. I also have a Master of Science in Taxation
21 from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State
22 University, 1986. In addition, I have attended a variety of continuing education
23 courses in conjunction with maintaining my accountancy license. I am a licensed

1 C.P.A. and attorney in the State of Michigan. I am also a Certified Financial
2 Planner™ professional and a Certified Rate of Return Analyst (“CRRRA”). Since
3 1981, I have been a member of the Michigan Association of Certified Public
4 Accountants. I am also a member of the Michigan Bar Association and the Society
5 of Utility and Regulatory Financial Analysts (“SURFA”). I have also been a
6 member of the American Bar Association (“ABA”), and the ABA sections on Public
7 Utility Law and Taxation.

8
9 **Q. Please summarize your professional experience.**

10 **A.** Subsequent to graduation from the University of Michigan, and after a short period
11 of installing a computerized accounting system for a Southfield, Michigan realty
12 management firm, I accepted a position as an auditor with the predecessor CPA firm
13 to Larkin & Associates in July 1979. Before becoming involved in utility regulation
14 where the majority of my time for the past 35 years has been spent, I performed
15 audit, accounting, and tax work for a wide variety of businesses that were clients of
16 the firm.

17 During my service in the regulatory section of our firm, I have been involved
18 in rate cases and other regulatory matters concerning electric, gas, telephone, water,
19 and sewer utility companies. My present work consists primarily of analyzing rate
20 case and regulatory filings of public utility companies before various regulatory
21 commissions, and, where appropriate, preparing testimony and schedules relating to
22 the issues for presentation before these regulatory agencies.

1 I have performed work in the field of utility regulation on behalf of industry,
2 state attorneys general, consumer groups, municipalities, and public service
3 commission staffs concerning regulatory matters before regulatory agencies in
4 Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida,
5 Georgia, Hawaii, Indiana, Illinois, Kansas, Kentucky, Louisiana, Maine, Maryland,
6 Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York,
7 Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South
8 Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West
9 Virginia and Canada as well as the Federal Energy Regulatory Commission and
10 various state and federal courts of law.

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Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. On whose behalf are you appearing?

A. Larkin & Associates, PLLC, was retained by the Pennsylvania Office of Consumer Advocate (“OCA”) to review the rate requests of the FirstEnergy electric distribution utilities (“FE” or “Companies”). Accordingly, I am appearing on behalf of the OCA.

Q. Have you previously filed testimony before the Pennsylvania Public Utility Commission?

1 A. Yes. I have testified before the Pennsylvania Public Utility Commission (“PaPUC”
2 or “Commission”) previously on a number of occasions.

3

4 **Q. How will your testimony be organized?**

5 A. I will present an Overall Financial Summary that addresses the revenue increases
6 requested by FE for its electric utilities. I then address each of the utilities that are
7 the subject of the Company’s revenue requirement filings in these proceedings. I
8 then present an explanation of the organization and content of my exhibits for each
9 system, which are attached to my testimony. That discussion is then followed by
10 sections on Rate Base and Net Operating Income adjustments, where I explain each
11 adjustment for each FE electric utility.

12

13 **Q. For which FE utilities are you addressing FE's revenue requirements?**

14 A. I am addressing the revenue requirements requested by FE for Metropolitan Edison
15 Company (“Met-Ed” or “ME”), Pennsylvania Electric Company (“Penelec” or
16 “PN”), Pennsylvania Power Company (“Penn Power” or “PP”), and West Penn
17 Power Company (“West Penn” or “WP”), (collectively "Companies").

18

19 **Q. Have you prepared any exhibits to accompany your testimony?**

20 A. Yes. Exhibits LA-ME-1, LA-PN-1, LA-PP-1 and LA-WP-1 present Accounting
21 Schedules that quantify each of the recommendations in my testimony for Met-Ed,
22 Penelec, Penn Power, and West Penn, respectively.

1 Exhibit LA-2 presents selected non-confidential material that is referenced in
2 my testimony and schedules.

3 Exhibit LA-3 presents selected confidential material that is referenced in my
4 testimony and schedules.

5

6 **II. SCOPE AND PURPOSE OF TESTIMONY**

7 **Q. What revenue increase have the Companies requested?**

8 A. FE has presented four revenue requirement calculations where the Company applies
9 a rate of return to rate base and compares the required operating income with its
10 adjusted operating income and uses the difference to derive a revenue deficiency or
11 sufficiency. FE's Exhibit CVF-3 contains the revenue requirement results for these
12 utilities.

13 On August 4, 2014, Met-Ed filed with the Commission Tariff Electric -- Pa.
14 P.U.C. No. 52 (Tariff No. 52) which reflects an increase in annual distribution
15 revenues of \$151.9 million, or 11.5% of its total electric operating revenues. Met-
16 Ed's current distribution base rates were established pursuant to the Commission's
17 Final Order entered January 11, 2007 at Docket No. R-00061366, which was the last
18 base rate proceeding for the Company. That proceeding resulted in a decrease in
19 Met-Ed's distribution base rates.

20 Penelec filed with the Commission Tariff Electric -- Pa. P.U.C. No. 81 (Tariff
21 No. 81) which reflects an increase in annual distribution revenues of \$119.8 million,
22 or 8.6% of its total electric operating revenues. Penelec's current distribution base
23 rates were established pursuant to the Commission's Final Order entered January 11,

1 2007 at Docket No. R-00061366, which was the last base rate proceeding for the
2 Company. That proceeding resulted in a decrease in Penelec's distribution base
3 rates.

4 Penn Power filed with the Commission Tariff Electric – Pa. P.U.C. No. 36
5 (Tariff No. 36) which reflects an increase in annual distribution revenues of \$28.5
6 million, or 8.7% of its total electric operating revenues. Penn Power's current
7 distribution base rates were established pursuant to the Commission's Final Order
8 issued July 22, 1998 in the proceeding at Docket No. R-00974149, in which Penn
9 Power's bundled rates for electric service were functionally unbundled. Prior to that
10 case, Penn Power had last increased its base rates pursuant to a Commission Final
11 Order entered on May 3, 1988 in a general base rate proceeding at Docket No. R-
12 870732.

13 West Penn filed Tariff Nos. 38 and 40 which set forth proposed rates
14 designed to produce, in aggregate, an increase in the Company's annual distribution
15 revenue of \$115.5 million, or 8.4% of its total electric operating revenues. West
16 Penn's current distribution base rates were established when West Penn's base rates
17 were functionally unbundled pursuant to the Commission's Final Order entered
18 November 19, 1998 at Docket No. R-00973981. Prior to that case, West Penn had
19 last increased its base rates pursuant to the Commission's Final Order entered
20 December 29, 1994 in a general base rate proceeding at Docket No. R-00942986.

21
22 **Q. What is the purpose and scope of your testimony?**

1 A. Larkin & Associates, PLLC was engaged by the OCA to conduct a review and
2 analysis and to present testimony regarding certain rate base, operating income and
3 revenue requirement aspects of the filing.

4 The purpose of my testimony is to present to the Commission the appropriate
5 test period rate base, overall rate of return and utility operating income, as well as the
6 appropriate overall revenue requirement and rate increase for the Companies in this
7 proceeding.

8
9 **Q. What capital structure and return on equity have you used?**

10 A. In the determination of the OCA's recommended overall revenue requirement and
11 revenue increase, I have used the capital structure and cost rates recommended by
12 OCA witness Griffing, which include a 9.27 percent rate of return on common
13 equity.¹ I applied the resulting overall rate of return to my recommended adjusted
14 rate base for each Company in these proceedings.

15
16 **Q. What information did you review in developing your testimony?**

17 A. In developing this testimony, I have reviewed and analyzed the Companies' filings,
18 supporting testimonies, exhibits, filing requirements and workpapers; the
19 Companies' responses to data requests by the OCA and other parties; prior
20 Commission orders; and other relevant financial documents and data.

21

¹ I will refer to this as the "return on equity" or "ROE".

1 **III. SUMMARY OF FINDINGS AND CONCLUSIONS**

2 **Q. Please summarize your findings and conclusions in this case.**

3 A. I have reached the following findings and conclusions with respect to the
4 Companies' revenue requirements using OCA witness Dr. Griffing's recommended
5 cost of capital, and without consideration of the quality of service:

6 As shown on Exhibit LA-ME-1², Schedule A, page 1, Met-Ed's
7 proposed distribution revenue increase of \$152.643 million should be reduced by
8 \$120.076 million. The distribution revenue increase for Met-Ed should be no
9 greater than \$32.567 million.

10 As shown on Exhibit LA-PN-1³, Schedule A, page 1, Penelec's proposed
11 distribution revenue increase of \$120.316 million should be reduced by \$59.531
12 million. The distribution revenue increase for Penelec should be no greater than
13 \$60.785 million.

14 As shown on Exhibit LA-PP-1⁴, Schedule A, page 1, Penn Power's proposed
15 distribution revenue increase of \$29.557 million should be reduced by \$26.376
16 million. The distribution revenue increase for Penn Power should be no greater than
17 \$3.181 million.

18 As shown on Exhibit LA-WP-1⁵, Schedule A, page 1, West Penn's proposed
19 distribution revenue increase of \$78.619 million should be reduced by \$45.742
20 million. The distribution revenue increase for West Penn should be no greater than
21 \$32.877 million.

² This Exhibit is attached to my Met-Ed testimony.

³ This Exhibit is attached to my Penelec testimony.

⁴ This Exhibit is attached to my Penn Power testimony.

⁵ This Exhibit is attached to my West Penn testimony.

1

2 **Q. Have you calculated the impact on the revenue requirement of a 10 and 25 basis**
3 **point reduction in the return on equity?**

4 A. Yes. As noted in OCA witness Griffing's testimony, OCA witness Alexander has
5 raised numerous concerns as to the customer service, quality, and reliability of
6 service for these Companies. The Commission should consider these concerns when
7 setting the ROE. Dr. Griffing notes further that, in keeping with Commission
8 practice, reductions of 10 to 25 basis points from his quantitative ROE
9 recommendation could be appropriate, with the larger reductions made for the
10 Companies with the least adequate service. To facilitate consideration of such
11 quality of service issues, I have calculated revenue impacts on each utility of a 10
12 and 25 basis point reduction in the return on equity.

13 For Met-Ed, a 10 basis point reduction in the ROE would reduce the revenue
14 requirement by approximately \$1.144 million. A 25 basis point reduction in the
15 ROE would reduce the revenue requirement by approximately \$2.861 million.

16 For Penelec, a 10 basis point reduction in the ROE would reduce the revenue
17 requirement by approximately \$1.331 million. A 25 basis point reduction in the
18 ROE would reduce the revenue requirement by approximately \$3.331 million.

19 For Penn Power a 10 basis point reduction in the ROE would reduce the
20 revenue requirement by approximately \$0.31 million. A 25 basis point reduction in
21 the ROE would reduce the revenue requirement by approximately \$0.77 million.

1 For West Penn a 10 basis point reduction in the ROE would reduce the
2 revenue requirement by approximately \$1.097 million. A 25 basis point reduction in
3 the ROE would reduce the revenue requirement by approximately \$2.741 million.
4

5 **IV. ORGANIZATION OF ACCOUNTING SCHEDULES**

6 **Q. How are the OCA's accounting schedules organized?**

7 A. The OCA's revenue requirement and accounting schedules for each utility are
8 presented in Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and LA-WP-1. These Exhibits
9 present Accounting Schedules that quantify each of the recommendations in my
10 testimony for Med-Ed, Penelec, Penn Power, and West Penn, respectively. Each of
11 those Exhibits is organized into summary schedules and adjustment schedules. The
12 summary schedules consist of four sets of Schedules A, A-1, B, B.1, C, C.1 and D.
13 Exhibits LA-ME-1, LA-PN-1, LA-PP-1 and LA-WP-1 also contain rate base
14 adjustment Schedules B-1 through B-8, and net operating income adjustment
15 Schedules C-1 through C-15. The description of these schedules in the section
16 immediately below applies to the Companies' summary schedules as well as the
17 individual sets of summary schedules.

18 19 **Q. What is shown on Schedule A of Exhibit LA-ME-1, LA-PN-1, LA-PP-1, and 20 LA-WP-1?**

21 A. On Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and LA-WP-1, Schedule A, page 1,
22 presents the overall financial summary, giving effect to all the adjustments I am
23 recommending in my testimony. This schedule presents the change in the

1 Companies' gross revenue requirement needed for the Companies to have the
2 opportunity to earn the rate of return I have used on the adjusted rate base. The rate
3 base and operating income amounts are taken from Schedules B and C, respectively.
4 The overall rate of return on rate base with an ROE of 9.27 percent, as recommended
5 by OCA witness Griffing, is provided on Schedule D of Exhibits LA-ME-1, LA-PN-
6 1, LA-PP-1, and LA-WP-1.

7 Column A of Schedule A replicates the Companies' proposed calculations of
8 the revenue deficiency. Column B of Schedule A presents the OCA's determination
9 of the base rate revenue deficiency. Column C shows the differences between the
10 Companies' request and the OCA's recommendation.

11 As described above, the operating income deficiency shown on line 5 of
12 Schedule A is obtained by subtracting the adjusted operating income on line 4
13 (operating income as adjusted) from the required operating income on line 3. Line 7
14 represents the gross revenue requirement, which is obtained by multiplying the
15 income deficiency by the Gross Revenue Conversion Factor ("GRCF"). Line 9
16 presents the amount of revenue increase after rounding differences.

17
18 **Q. What is shown on Schedule A, page 2 of Exhibits LA-ME-1, LA-PN-1, LA-PP-1,**
19 **and LA-WP-1?**

20 **A.** Schedule A, page 2, presents a reconciliation of the revenue requirement and shows
21 the approximate impact of each adjustment.

22

1 **Q. What is shown on Schedule A-1 of Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and**
2 **LA-WP-1?**

3 A. Schedule A-1 shows the derivation of the GRCF. The GRCF is used to convert the
4 net operating income deficiency into a revenue deficiency amount.

5

6 **Q. How does the GRCF recommended by OCA compare with the GRCF contained**
7 **in the Companies' filing?**

8 A. As shown on Schedule A-1, of Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and LA-
9 WP-1, the GRCF I have used for each utility corresponds to the GRCF used for that
10 utility in the FE filings.

11

12 **Q. What is shown on Schedule B of Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and**
13 **LA-WP-1?**

14 A. Schedule B presents the Companies' proposed adjusted test year rate base and
15 OCA's proposed adjusted test year rate base. The beginning rate base amounts
16 presented on Schedule B are taken from each Company's filing for the fully
17 projected future test year ("FPFTY") ending April 30, 2016. OCA's recommended
18 adjustments to rate base are summarized on Schedule B.1.

19 Schedules B-1 through B-8 provide further support and calculations for the
20 rate base adjustments I am recommending.

21

22 **Q. What is shown on Schedule C of Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and**
23 **LA-WP-1?**

1 A. The starting point on Schedule C is the Companies' adjusted test year net operating
2 income, as provided on each Company's Exhibit RAD-2. OCA's adjustments to the
3 Companies' adjusted test year revenues and expenses are summarized on Schedule
4 C.1. Each of the adjustments is discussed in my testimony.

5 Schedules C-1 through C-15 provide further support and calculations for the
6 net operating income adjustments I am recommending.

7

8 **Q. What is shown on Schedule D of Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and**
9 **LA-WP-1?**

10 A. Schedule D summarizes the capital structure and cost of capital that was proposed by
11 the Companies and the capital structure and cost of capital that I have used to
12 compute the revenue requirement deficiency for each of the Companies. The OCA's
13 recommended capital structure, cost rate, and ROE are sponsored by OCA witness
14 Griffing.

15

16 **Q. Have you prepared a list of which of the OCA's proposed adjustments to rate**
17 **base and net operating income pertain to each Company?**

18 A. Yes. The following table summarizes which of the OCA's proposed adjustments to
19 rate base and net operating income pertain to each Company:

OCA Rate Base and Net Operating Income Adjustments Listing by Company					
Adjustment Schedule	Adjustment Description	Met-Ed	Penelec	Penn Power	West Penn
		Exhibit LA-ME-1	Exhibit LA-PN-1	Exhibit LA-PP-1	Exhibit LA-WP-1
	Rate Base Adjustments				
B-1	Average FPFTY Rate Base	Yes	Yes	Yes	Yes
B-2	Deferred Storm Damage Expense	Yes	Yes	N/A	Yes
B-3	Depreciation Reserve Related to Legacy Meters	Yes	Yes	Yes	Yes
B-4	Cash Working Capital - Operating Expenses	Yes	Yes	Yes	Yes
B-4.1	Cash Working Capital - Interest Expense	Yes	Yes	Yes	Yes
B-5	Transmission Project (Intangible Plant)	Yes	Yes	N/A	N/A
B-6	Adjust Mobile Work Management System Cost	Yes	Yes	N/A	N/A
B-7	ADIT - Change in Tax Accounting Method	Yes	Yes	Yes	Yes
B-8	ADIT - Correction of Error in Filing	N/A	Yes	N/A	N/A
	Net Operating Income Adjustments				
C-1	Consolidated Tax Savings	Yes	Yes	Yes	N/A
C-2	Miscellaneous Expenses	Yes	Yes	Yes	Yes
C-3	Deferred Storm Damage Amortization Expense	Yes	N/A	N/A	Yes
C-4	Deferred Merger Storm Damage Amortization Expense	Yes	Yes	N/A	N/A
C-5	Legacy Meters Amortization Expense	Yes	Yes	Yes	Yes
C-6	Payroll Expense	Yes	Yes	Yes	Yes
C-7	Payroll Tax Expense	Yes	Yes	Yes	Yes
C-8	Employee Benefits Expense	Yes	Yes	Yes	Yes
C-9	Depreciation Expense - Transmission Project (Intangible Plant)	Yes	Yes	N/A	N/A
C-10	Depreciation Expense - Mobile Work Management System (Intangible Plant)	Yes	Yes	N/A	N/A
C-11	Vegetation Management Expense	Yes	Yes	Yes	Yes
C-12	Rate Case Expense	Yes	Yes	Yes	Yes
C-13	Interest Synchronization	Yes	Yes	Yes	Yes
C-14	Pension Expense	Yes	Yes	Yes	Yes
C-15	OPEB Expense	Yes	Yes	Yes	Yes

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V. RATE BASE

Q. Have you prepared a schedule that summarizes OCA’s proposed adjustments to rate base?

A. Yes. As noted above, in Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and LA-WP-1 the adjusted rate base is shown on Schedule B and the adjustments to each Company’s proposed rate base are summarized on Schedule B.1. A comparison of each Company’s proposed rate base and OCA’s recommended rate base is presented below:

1 **B-1, Average Rate Base for the Fully Projected Future Test Year (All Four FE**
2 **Utilities)**

3 **Q. Please explain the adjustment for the average rate base for the Fully Projected**
4 **Future Test Year.**

5 A. This adjustment for each Company is shown on Schedule B-1 of the respective
6 exhibits, LA-ME-1, LA-PN-1, LA-PP-1 and LA-WP-1. Focusing on the Met-Ed
7 adjustment, which is shown on Exhibit LA-ME-1, Schedule B-1, for purposes of
8 explanation, the original cost at the beginning and end of the FPFTY are shown in
9 columns A⁶ and B. The rate base elements requested by Met-Ed are shown in
10 column C. The corresponding average FPFTY balances for each rate base
11 component are shown in column D.⁷ The differences between Met-Ed's proposed
12 rate base and the average FPFTY rate base, by rate base component, are shown in
13 column E. For Met-Ed, the use of average FPFTY rate base balances results in an
14 increase to FPFTY rate base of \$14.901 million.

15 The calculations for Penelec, Penn Power and West Penn are similar and are
16 shown on Schedule B-1 of Exhibits LA-PN-1, LA-PP-1 and LA-WP-1, respectively.

17
18 **Q. Does Act 11 allow utilities use of a fully projected future test year?**

19 A. Yes. Act 11 allows Pennsylvania utilities to utilize a FPFTY as the basis for
20 determining their revenue requirement in a base rate case.

21

⁶ The amounts shown for electric Plant in Service and Depreciation Reserve reflect the Companies' projected balances as of April 30, 2015, per Met-Ed Exhibit RAD-46. For convenience sake, balances at March 31, 2015, the end of the FTY are used for rate base additions and deductions, without adjustments as representative of balances as of May 1, 2015, the start of the FPFTY, per data request OCA-ME-X-2.

⁷ These average FPFTY balances are based on an average of the amounts shown in columns A and B.

1 **Q. How did FirstEnergy apply Act 11 in its current rate case?**

2 A. For determining rate base, FirstEnergy applied Act 11 by projecting capital
3 additions, revenues and operating expenses through the end of the FPFTY, and used
4 estimated future amounts as of April 30, 2016, the end of the FPFTY, rather than
5 using an average FPFTY concept for rate base components such as net plant in
6 service. For operating expenses such as pay increases, FirstEnergy has used
7 expenses, which are beyond the FPFTY. FirstEnergy has done this by including
8 annualized increases occurring within and beyond the FPFTY, including pay
9 increases projected for May 1, 2016.

10
11 **Q. Do you agree with FE's use of April 30, 2016 values for the fully projected
12 future test year rate base?**

13 A. No. Act 11 allows the use of a fully projected future test year as the basis for
14 determining revenue requirement. Thus, the rate base should be based on the average
15 for the FPFTY, rather than upon values as of a single date at the end of the FPFTY.
16 The use of an average FPFTY properly matches the collection of the revenue
17 requirement during the first year of new rates, i.e. with the FPFTY beginning on
18 May 1, 2015 and continuing through April 30, 2016.

19
20 **Q. In measuring FE's FPFTY rate base, what has FE proposed for the
21 determination of jurisdictional rate base for its electric distribution utilities?**

22 A. For each of the four electric distribution utilities, FE proposes that a year-end April
23 30, 2016 rate base be used for the purpose of determining its revenue requirement in

1 the current rate case. However, the use of a year-end rate base to measure fully
2 projected future test year results in a mis-match, since FE utilities would not have
3 that level of rate base throughout the fully projected test year period. If a utility's
4 jurisdictional rate base has changed during the test year measurement period, it could
5 cause a significant distortion to the measurement of the utility's earnings if year-end
6 values are used for major rate base components, such as net plant in service.

7
8 **Q. Has a year-end rate base been used in previous FE utility base rate cases?**

9 A. Yes, but those base rate cases pre-dated Act 11 and were based on a future test year
10 that ended before rates went into effect. On the other hand, the purpose of the
11 FPFTY is to calculate the utility's revenue requirement that will be in effect, on
12 average, for the rate year, i.e., for the first full year of the new rates. Thus, the
13 FPFTY should use an average test year to determine the utility's revenue requirement
14 for that 12-month forecasted calendar year rate effective period.

15
16 **Q. Can you provide a simple example of how a year-end rate base would compare
17 to the use of actual cost information for the calendar year, on average?**

18 A. Yes. The following illustration assumes that the utility had jurisdictional rate base
19 investment of \$6.5 billion on January 1 and \$6.74 billion on December 31 of the
20 FPFTY (which is a calendar year in this illustrative example), that the investment
21 had been added ratably during the calendar year, and that the amount of actual net
22 operating income for the year was approximately \$540 million:

Simplified Comparison of Year-End and Average Calendar Rate Base - Illustrative Example
(Thousands of Dollars)

Line No.	Description	December 31 (Calendar Year-End) Rate Base (A)	Average Rate Base for Applicable Calendar Year (B)	Difference (C)
1	Jurisdictional Rate Base	\$ 6,740,000	\$ 6,620,000	\$ 120,000
2	Required Return	8.12%	8.12%	
3	Operating Income Required	\$ 547,288	\$ 537,544	\$ 9,744
4	Net Operating Income Available	\$ 540,000	\$ 540,000	
5	Operating Income Deficiency (Excess)	\$ 7,288	\$ (2,456)	\$ 9,744
6	Gross Revenue Conversion Factor	1.6596	1.6596	
7	Revenue Deficiency (Sufficiency)	\$ 12,095	\$ (4,076)	\$ 16,171

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Q. Has the rate base for each of the FE utilities changed substantially from the beginning to the end of the FPFTY in the current case?

10

11

A. No. The change in each of the FE utility's rate base from the beginning to the end of the FPFTY, i.e., the difference between average FPFTY rate base, as I am

12

13

recommending, versus the end-of-period FPFTY rate base that FE proposes, is not a major driver of the Companies' revenue increase requests in the current rate cases.

14

15

In fact, for two of the four FE utilities (Met-Ed and Penelec) the use of an average

16

FPFTY rate base, other things being equal, results in an upward adjustment to rate

17

base in the current rate case.

1

2 **Q. Does proper matching dictate that an average rate base for the fully projected**
3 **future test year be used?**

4 A. Yes. For purposes of determining the utility's revenue requirement for the rate year
5 that constitutes the FPFTY, an average rate base concept should be used. This is
6 necessary for proper matching of the measurement information.

7

8 **Q. Should an average test year rate base concept for the FPFTY period be**
9 **employed in the current proceeding to determine the revenue requirement for**
10 **each of the four FE electric distribution utilities?**

11 A. Yes.

12

13 **Q. Are you familiar with the use of a forecasted future test year in other**
14 **jurisdictions?**

15 A. Yes. I am familiar with the use of forecasted future test years in a number of other
16 jurisdictions, including from my review of specific utility filings in jurisdictions,
17 such as California and Hawaii, among others. It is common in states where a fully
18 projected future test year is used to employ an average test year concept for purposes
19 of measuring rate base and to determine the utility's revenue requirement.

20

21 **Q. What adjustment does the use of an average rate base for the FPFTY produce**
22 **for the FE utilities?**

1 A. As shown on Exhibit LA-ME-1, Schedule B-1 for Met-Ed, this adjustment increases
2 rate base by \$14.901 million.

3 As shown on Exhibit LA-PN-1, Schedule B-1 for Penelec, this adjustment
4 increases rate base by \$11.786 million.

5 As shown on Exhibit LA-PP-1, Schedule B-1 for Penn Power, this
6 adjustment decreases rate base by \$4.229 million.

7 As shown on Exhibit LA-WP-1, Schedule B-1 for West Penn, this adjustment
8 decreases rate base by \$7.261 million.

9

10 **B-2, Deferred Storm Damage (Met-Ed, Penelec, and West Penn)**

11 **Q. Please explain your adjustment regarding deferred storm damage.**

12 A. This adjustment removes from rate base the Companies' requested amounts for
13 deferred storm costs. As explained in additional detail in conjunction with
14 adjustments C-3 and C-4, which address amortization of deferred storm costs,
15 recovery of such costs through amortization is allowed; however, including
16 unamortized amounts of expenses in rate base is not. Hence, the Companies'
17 proposed rate base amounts should be removed.

18

19 **Q. Have the Companies explained in response to discovery why they have
20 proposed to include deferred storm costs in rate base in the current rate cases?**

21 A. Yes. The Companies' response to I&E-ME-RE-9-D, for example, explains that:

22 The total amount of storm damage cost of \$64,964,000 is
23 included in rate base because none of the deferred storm
24 damage expenditures have been recovered in rates. The
25 \$21,655,000 of expense shown on Met-Ed Exhibit RAD-2, p.

1 24, is the annual amortization of storm damage costs over a
2 three-year period, which will commence when rates in this
3 case go into effect.

4 Similarly, the Companies' response to I&E-PN-RE-4-D for Penelec states

5 that:

6 The total amount of storm damage cost of \$12,795,000 is
7 included in rate base because none of the deferred storm
8 damage expenditures have been recovered in rates. The
9 \$4,265,000 of expense shown on Penelec Exhibit RAD-2, p.
10 24, is the annual amortization of storm damage costs over a
11 three-year period, which will commence when rates in this
12 case go into effect.

13 Similarly, the Companies' response to I&E-WP-RE-3-D for West Penn states

14 that:

15 The total amount of storm damage cost of \$15,465,000 is
16 included in rate base because none of the deferred storm
17 damage expenditures has been recovered in rates. The
18 \$5,155,000 of expense shown on West Penn Exhibit RAD-2,
19 p. 24, is the annual amortization of storm damage costs over a
20 three-year period, which will commence when rates in this
21 case go into effect.

22 In addition, the Companies' response to I&E-ME-RE-1-D, part G, for Met-Ed

23 states as follows:

24 The Company has included in rate base the deferred storm
25 damages balances for Winter Storm Nika (\$13,327,000),
26 approved at Docket No. P- 2014-2412229, Hurricane Sandy
27 (\$21,497,000), approved at Docket No. P-2013-2351260, and
28 distribution non-capital storm expenses that exceeded 125% of
29 storm costs included in base rates (\$30,140,000) between the
30 period of February 25, 2011 through September 30, 2012 as a
31 result of the FirstEnergy and Allegheny Merger approved at
32 Docket Nos. A-2010- 2176520 and A-2010-2176732,
33 including but not limited to Hurricane Irene, the October 2011
34 snowstorm, and Tropical Storm Lee. These deferred storm
35 damage balances of \$64,964,000 are a significant nonearning
36 "investment" by the Company in re-establishing electric
37 service to customers during emergency crisis storm
38 management situations. The Commission's recognition of the

1 importance of these cost levels enabled the Company to defer
2 these storm damage expenditures for future rate recovery. No
3 approvals for cost recovery in the current proceeding can
4 make up for the lost value associated with these non-earning
5 “investments” in customer service. Therefore, future rate
6 recovery would be incomplete without recognition of the
7 appropriate carrying costs associated with these significant
8 deferred storm damage costs which is an important part of rate
9 recovery plan. The return “of” and “on” these deferred
10 expenditures would enable the Company to be made whole for
11 its “investment” of returning customers to service during
12 difficult storm management circumstances. The length of time
13 to achieve full recovery can only be successfully mitigated
14 with recognition of the carrying value associated with these
15 deferred costs.

16

17 **Q. Is storm damage expense an investment, as the Company has claimed?**

18 A. No, it is an operating expense, which the Companies have been allowed to defer.

19

20 **Q. Have the Companies admitted that their budgets should have reflected an
21 amortization of storm costs?**

22 A. Yes. For example, the Companies' response to I&E-ME-RE-2-D, part C, states that:

23 The Company's budget should have reflected an amount for
24 deferred storm amortization for Hurricane Sandy and Winter
25 Storm Nika in accordance with the provisions of the
26 Commission's orders at Docket Nos. P-2013-2351260 and P-
27 2014-2412229. There were no deferred storm amortization
28 requirements associated with the storm deferral approved at
29 Docket Nos. A-2010-2176520 and A-2010-2176732 (Order
30 approving the settlement of the FirstEnergy/Allegheny Power
31 merger proceeding).

32

33 **Q. If any amount were to be considered for FPFTY rate base inclusion for any
34 deferred storm cost, would it need to reflect amortization through the FPFTY?**

1 A. Yes, it would. While I am not recommending that any amount of deferred storm cost
2 be included in rate base, because this is an operating expense not an investment, if
3 any amounts were to be considered for inclusion in FPFTY rate base, the amounts
4 would need to be reduced by amortization occurring prior to and during the FPFTY.
5 The FirstEnergy utilities have not done this for any of their requested rate base
6 inclusions of deferred storm cost.

7
8 **Q. Do you agree with their proposed inclusion of deferred storm cost in rate base?**

9 A. No. As noted above, the recovery of storm costs is provided through an appropriate
10 amortization, but a return on these operating expenses is not allowed.

11
12 **Q. What adjustment does this produce for each of the FE utilities?**

13 A. As shown on Exhibit LA-ME-1, Schedule B-2, rate base for Met-Ed is reduced by
14 \$64.964 million.

15 As shown on Exhibit LA-PN-1, Schedule B-2, rate base for Penelec is
16 reduced by \$12.795 million.

17 As shown on Exhibit LA-PP-1, Schedule B-2, this adjustment is not needed
18 for Penn Power. Penn Power did not attempt to include deferred storm costs in rate
19 base as shown on Exhibit LA-PP-1, Schedule B, line 12.

20 As shown on Exhibit LA-WP-1, Schedule B-2, rate base for West Penn is
21 reduced by \$15.465 million.

1 As I discuss below in conjunction with OCA adjustments C-3 and C-4, an
2 expense amortization for deferred storm costs is allowed but no rate base return is
3 provided in these deferred operating expenses.
4

5 **B-3, Depreciation Reserve Related to Legacy Meters (All Four FE Utilities)**

6 **Q. Please explain your adjustment for a decrease to depreciation reserve related to**
7 **legacy meters.**

8 A. This adjustment is related to an expense adjustment for legacy meters, detailed in
9 Schedule C-5, which is discussed in detail in a subsequent section of my testimony.

10 As shown on Exhibit LA-ME-1, Schedule B-3, for Met-Ed there is a
11 difference of \$1.904 million between the \$16.632 million end of FPFTY balance of
12 legacy meter accumulated depreciation used by FirstEnergy and the May 1, 2015
13 beginning of FPFTY balance of \$14.728 million that I have used as the basis for the
14 legacy meter amortization. As shown on Exhibit LA-ME-1, Schedule C-5, for Met-
15 Ed, the OCA's recommended legacy meter amortization for the FPFTY is \$2.785
16 million. One half of this, or \$1.392 million, is used as the average increase during the
17 FPFTY in the accumulated depreciation/amortization reserve amount for legacy
18 meters. The net of the \$1.904 million decrease in the accumulated
19 depreciation/amortization reserve amount for legacy meters and the \$1.392 million
20 average FPFTY increase results in a net increase to Met-Ed's rate base for legacy
21 meters of \$511,000 on Schedule B-3.

22 As shown on Exhibit LA-PN-1, Schedule B-3, for Penelec this similar
23 adjustment calculation process results in a \$3.081 million decrease in the

1 accumulated depreciation/amortization reserve amount for legacy meters and a
2 \$1.451 million average FPFTY increase for amortization of legacy meter costs. This
3 results in a net increase to Penelec's rate base for legacy meters of \$1.630 million.

4 As shown on Exhibit LA-PP-1, Schedule B-3, for Penn Power this similar
5 adjustment calculation process results in a \$610,000 decrease in the accumulated
6 depreciation/amortization reserve amount for legacy meters and a \$285,000 average
7 FPFTY increase for amortization of legacy meter costs. This results in a net increase
8 to Penelec's rate base for legacy meters of \$325,000.

9 As shown on Exhibit LA-WP-1, Schedule B-3, for West Penn this similar
10 adjustment calculation process results in a \$2.279 million decrease in the
11 accumulated depreciation/amortization reserve amount for legacy meters and a
12 \$508,000 average FPFTY increase for amortization of legacy meter costs. This
13 results in a net increase to rate base for legacy meters of \$1.771 million.

14
15 **B-4, Cash Working Capital (All Four FE Utilities)**

16 **Q. What is cash working capital?**

17 A. Cash working capital ("CWC") is the cash needed by the Company to cover its day-
18 to-day operations. If the Company's cash expenditures, on an aggregate basis,
19 precede the cash recovery of expenses, investors must provide cash working capital.
20 In that situation, a positive cash working capital requirement exists. In this case, the
21 cash working capital requirement is an addition to rate base as investors are
22 essentially supplying these funds.

1 **Q. Please summarize the standard procedure utilized to calculate a utility's cash**
2 **working capital requirement.**

3 A. The normal procedure for calculating a utility's cash working capital requirement is
4 to first calculate the lag with which revenue is received from customers. Second, the
5 lag with which the utility pays for the various types of cash expenses such as wages,
6 benefits, etc., is then determined. Third, a net lag for each type of cash expense is
7 calculated by subtracting the expense payment lag from the revenue lag. Fourth, the
8 net lag is multiplied by the average daily amount of each type of cash expense to
9 calculate the cash working capital requirement for that item. Finally, the individual
10 items are summed to determine the total cash working capital requirement.

11

12 **Q. Have other Pennsylvania utilities used that procedure?**

13 A. Yes. For example, Pennsylvania American Water Company has used this procedure
14 for cash working capital in its rate cases including Docket No. R-2013-2355276.

15

16 **Q. Did the FirstEnergy utilities follow that procedure?**

17 A. No.

18

19 **Q. Please summarize the procedure followed by the FirstEnergy utilities to**
20 **calculate their requested cash working capital allowances.**

21 A. The FE utilities have developed their cash working capital requirement by
22 determining the lag in the receipt of revenue. They have then multiplied that lag by
23 total revenues to determine a gross working capital requirement. The Companies

1 have then multiplied the average daily expense associated with each element of their
2 total claimed cost of service by the lag in the payment of that cost to obtain the
3 working capital provided by the payment of expenses. They have then subtracted
4 the total working capital provided by the lag in the payment of expenses from the
5 gross working capital requirement associated with the receipt of revenue to obtain a
6 net working capital requirement.

7
8 **Q. How did the Companies treat the non-cash expenses included in their revenue**
9 **requirement?**

10 A. While presented differently, the procedure followed by the Companies is no different
11 than including every element of their revenue requirements in the calculation of cash
12 working capital. For those expenses for which a cash payment is made, the
13 Companies have reflected a working capital requirement that is the same as would be
14 calculated under the standard methodology. The difference is that the Companies
15 have also included a working capital requirement for non-cash expenses. In
16 particular, the Companies have included depreciation, amortization, deferred income
17 taxes and other non-cash expenses with a zero day payment lag. As a result, the
18 Companies have claimed a working capital requirement for each of these items that
19 is equal to the average daily expense times the revenue lag. The Companies have
20 even included operating income, both return on equity and interest on long-term debt
21 with a zero day payment lag. The net effect is that the Companies have significantly
22 overstated their cash working capital requirements.

23

1 **Q. Have you identified any other problems with the Companies' lead lag studies?**

2 A. Yes. I have identified a number of other corrections which are required to more
3 accurately determine cash working capital. Accordingly, I have presented a revised
4 cash working capital analysis for each Company.

5

6 **Q. Would you summarize the revisions that you have made to the Companies' cash
7 working capital requests?**

8 A. Yes. I have made the following revisions to the lead-lag studies utilized by the
9 Companies:

- 10 • I have excluded all non-cash expenses, including depreciation, amortization,
11 deferred income taxes and uncollectibles.
- 12 • I have excluded the return on equity component of operating income and
13 have included interest expense on long-term debt with a lag of 91.3 days.
14 This lag reflects the fact that the Companies' debt is long-term debt on which
15 interest is paid semi-annually.
- 16 • The Companies included uncollectibles at a zero lag in their other O&M
17 expense lag. In addition to excluding uncollectibles as a non-cash item, I
18 revised the overall lag associated with other O&M to separately account for
19 interest on customer deposits being paid annually.
- 20 • I have removed the lobbying cost portion of the Companies' requested CWC
21 inclusion of EEI dues prepayments.
- 22 • I have removed a large new item for unamortized pension contributions that
23 the Companies have attempted to include in the prepayments component of

1 CWC for the first time in the current rate cases (see additional discussion
2 below).

- 3 • Finally, I have adjusted the expenses included in the lead-lag study to reflect
4 my adjustments to the Companies' cash operating expenses.

5
6 **Q. How was the proper treatment of non-cash expenses addressed in the most
7 recent Commission order for Met-Ed and Penelec?**

8 A. The Commission's January 11, 2007 order in Cases R-00061366 and R-00061367 et
9 al. discussed the treatment of non-cash items such as depreciation, amortization,
10 deferred income taxes and uncollectibles at pages 72-76. As stated at page 74 of that
11 Order:

12 The OCA contended that the Commission has held that no
13 consideration should be given to non-cash items in the cash
14 working capital computation citing *Pa. PUC v. Phila.*
15 *Suburban Water Co.*, 58 Pa. PUC 668, 674 (1984) ("we
16 consider uncollectible accounts expense to be a non-cash
17 expense and, as such, no return allowance will be granted");
18 *Pa. PUC v. Mechanicsburg Water Co.*, 80 Pa. PUC 212, 226
19 (1993) (elimination of non-cash items, such as amortization
20 and written-off uncollectibles, from the cash working capital
21 calculation); *Pa. PUC v. Roaring Creek Water Co.*, 81 Pa.
22 PUC 285, 292 (1994); and *Pa. PUC v. Columbia Gas of Pa,*
23 *Inc.*, 74 Pa. PUC 282, 300 (1990) ("any expense which does
24 not require the utility to utilize cash funds does not require a
25 CWC allowance"). The OCA concluded that the Commission
26 should reject the Companies' inclusion of non-cash items in
27 its claim for cash working capital.

28
29 **b. ALJs' Recommendation**

30 The ALJs agreed with the OCA's position. The ALJs found
31 that the prior Commission decisions cited by the OCA
32 consistently reject including non-cash items in cash working
33 capital. The ALJs state that, while MEPN point out some
34 state utility commissions have adopted their position that non-

1 cash items should be included in cash working capital, the
2 decisions of other state utility commissions are not controlling
3 in this proceeding. The ALJs maintain that prior Commission
4 decisions are controlling. They concluded that MEPN have
5 cited no Commission decisions in support of their position that
6 non-cash items should be included within the calculation of
7 cash working capital nor have they proven that the
8 Commission should deviate from its prior decisions.
9 Therefore, the ALJs adopted the position of the OCA and
10 excluded the non-cash items from cash working capital. (R.D.
11 at 85).

12
13 At page 76 of that order, the Commission stated that:

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

28
29 **Q. Should the Commission’s practice of excluding non-cash items from cash**
30 **working capital continue to apply in the current FirstEnergy rate cases as well?**

31 **A.** Yes. The prior Commission’s decisions cited above consistently reject including
32 non-cash items in cash working capital for a very good reason: any expense which
33 does not require a utility to utilize cash funds does not require a CWC allowance.
34 This reason continues to apply in the current FirstEnergy rate cases. Consequently,
35 the Companies’ attempt to include non-cash items in their derivation of the CWC
36 allowance in the current case should be rejected.

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Q. How was the treatment of return on equity and the payment associated with interest on long term debt addressed in Met-Ed's and Penelec's last rate cases?

A. The Commission's January 11, 2007 Order in Cases R-00061366 and R-00061367 et al. discussed the treatment of these items at pages 79 – 81. As stated at pages 79-80 of that Order:

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).

At page 81 of the Order, the Commission stated that:

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 decision cited by the Companies are not controlling in this proceeding. Accordingly, the Exceptions of MEPN on this matter are denied.

1 **Q. How should the payment-lag for interest on long-term debt be reflected for**
2 **CWC in the current FirstEnergy rate cases?**

3 A. The payment-lag for long-term debt should be reflected as a cash expense with a
4 payment lag of 91.3 days, reflecting that interest on long-term debt is typically paid
5 semi-annually.

6
7 **Q. How was the CWC treatment for other O&M items, including interest on**
8 **customer deposits and pole rental expenses addressed in Met-Ed's and**
9 **Penelec's last rate cases?**

10 A. The Commission's January 27, 2007 Order in Cases R-00061366 and R-00061367 et
11 al. discussed the treatment of these items for CWC at pages 81 – 83. The OCA's
12 recommended CWC treatment for these items was adopted.

13
14 **Q. Should that treatment also be applied to these other O&M items in the current**
15 **case?**

16 A. Yes. The treatment for the interest on customer deposits and pole rental expenses for
17 CWC recommended by the OCA is appropriate and should continue to apply in the
18 current case.

19
20 **Q. Have you included in your CWC calculation the impact of both of these**
21 **adjustments to the other O&M expense lag?**

22 A. I have included the interest lag for customer deposits and have a placeholder for the
23 payment lag for pole rental expenses.

1 It was discovered in the preparation of the adjusted CWC calculation that
2 information concerning the amount of pole rental expense had not been broken out
3 separately in the FirstEnergy Companies' CWC calculations and also could not be
4 located in discovery. The pole rental expense amounts have therefore been
5 requested in recently issued OCA discovery, so that this item, if warranted, may be
6 updated at a later stage. It is not expected that adjusting for the pole rental payment
7 lag will have a major impact on the overall CWC allowances.

8

9 **Q. Did the Companies include Edison Electric Institute (“EEI”) lobbying costs in**
10 **their CWC request for prepayments?**

11 A. Yes. The Companies' prepaid EEI dues assessment amounts that were used for their
12 claimed prepayments component of CWC failed to exclude the portion of EEI dues
13 associated with lobbying. The EEI dues lobbying portion should be excluded from
14 CWC so that the Companies do not receive a rate base return on their lobbying
15 expenses. This exclusion of lobbying cost from the EEI prepayment is reflected on
16 Schedule B-4 for each Company.

17

18 **Q. Has the Company attempted to include any other items in its proposed CWC**
19 **component of rate base?**

20 A. Yes. The Company has attempted to include large amounts for an apparently new
21 item, Unamortized Cash Pension Contributions. This is shown on Schedule B-4,
22 page 1, line 26, of Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and LA-WP-1. The

1 amounts requested for rate base inclusion, via CWC, for this item appear to be
2 historically unprecedented and are:

- 3 • \$30.177 million for Met-Ed;
- 4 • \$17.912 million for Penelec;
- 5 • \$5.125 million for Penn Power; and
- 6 • \$28.393 million for West Penn.

7

8 **Q. Have the Companies explained why they are requesting this item?**

9 A. Yes. The Companies' response to OCA-XIV-4 states that:

10 The Company must pay certain costs before such costs are
11 charged to expense for accounting and ratemaking purposes.
12 Prepayments are cash expenditures that, while made in one
13 period, are not charged to expense until a future period. The
14 Company is using the same methodology of including
15 prepayments in its cash working capital claim in this case that
16 Met-Ed and Penelec employed in their 2006 base rate cases at
17 Docket Nos. R-00061366 and R-00061367. No testimony was
18 served by any of the parties in those cases challenging the
19 inclusion of prepayments in the calculation of cash working
20 capital. Therefore, the Commission adopted this treatment at
21 Docket Nos. R-00061366 and R-00061367 in its Order dated
22 January 11, 2007.

23

24 **Q. Were Unamortized Cash Pension Contributions included in the Met-Ed or
25 Penelec claim for CWC in Docket Nos. R-00061366 and R-00061367?**

26 A. It appears they were not. I have reviewed the Order in that proceeding as well as the
27 Met-Ed and Penelec CWC filings and the OCA's testimony on CWC in those
28 dockets and find no inclusion in CWC of any line item for Unamortized Cash
29 Pension Contributions.

30

1 **Q. What amount of prepayments was requested by Met-Ed and Penelec in Docket**
2 **Nos. R-00061366 and R-00061367?**

3 A. According to Met-Ed Exhibit MJS-1, pages 1 and 14 of 14⁸ in Docket No. R-
4 00061366, the total prepayments balance claimed by Met-Ed in that case was
5 \$916,000. Moreover, the items included are Prepaid PaPUC Assessments, Prepaid
6 Property & Liability Insurance and Prepaid EEI dues. There is no inclusion of any
7 Unamortized Cash Pension Contributions.

8 Similarly, according to Penelec Exhibit MJS-1, pages 1 and 14 of 14⁹ in
9 Docket No. R-00061367, the total prepayments balance claimed by Penelec in that
10 case was \$932,000. Moreover, the items included are PaPUC Assessments, Prepaid
11 Property & Liability Insurance and Prepaid EEI dues. There is no inclusion of any
12 Unamortized Cash Pension Contributions.

13

14 **Q. The Companies' response to OCA-XIV-4 states in part that: "No testimony was**
15 **served by any of the parties in those cases challenging the inclusion of**
16 **prepayments in the calculation of cash working capital. Therefore, the**
17 **Commission adopted this treatment at Docket Nos. R-00061366 and R-**
18 **00061367 in its Order dated January 11, 2007." How would any party challenge**
19 **the inclusion of Unamortized Cash Pension Contributions in a prepayments**
20 **component of CWC in Docket Nos. R-00061366 and R-00061367 if no**
21 **Unamortized Cash Pension Contributions were included?**

22 A. This is something that the Companies have not explained.

⁸ Copies of these pages are included in Exhibit LA-2, attached to my testimony.

⁹ Copies of these pages are also included in Exhibit LA-2, attached to my testimony.

1

2 **Q. Did the Commission authorize the inclusion of Unamortized Cash Pension**
3 **Contributions in CWC in Docket Nos. R-00061366 and R-00061367?**

4 A. No, it did not. The item was apparently not included in the Met-Ed or Penelec
5 claims made in those cases, and was therefore not addressed. No reasonable
6 inference can be made that inclusion in rate base of Unamortized Cash Pension
7 Contributions in CWC was authorized in Docket Nos. R-00061366 and R-00061367.
8 Indeed, it appears from a review of the record in that docket that this item was not
9 included in rate base for either Met-Ed or Penelec.

10

11 **Q. How do the components of the prepaids that Met-Ed and Penelec requested in**
12 **Docket Nos. R-00061366 and R-00061367 compare with the prepayments that**
13 **they are requesting in the current rate cases?**

14 A. The components of the prepayments that Met-Ed and Penelec requested in Docket
15 Nos. R-00061366 and R-00061367 are comparable with the prepayments that they
16 are requesting in the current rate cases, only without the inclusion of Unamortized
17 Cash Pension Contributions.

18 The prepayments in the current rate cases without that item include Prepaid
19 PaPUC Assessments, Prepaid Property & Liability Insurance and Prepaid EEI dues.
20 Those components are comparable to the prepayments that Met-Ed and Penelec in
21 Docket Nos. R-00061366 and R-00061367.

22 There was no Unamortized Cash Pension Contributions in the prepayments
23 that were requested by Met-Ed and Penelec in Docket Nos. R-00061366 and R-

1 00061367. Thus, any inference that the Companies have attempted to make that the
2 Commission adopted a CWC allowance in Docket Nos. R-00061366 and R-
3 00061367 that included a component for Unamortized Cash Pension Contributions is
4 contrary to the facts.

5
6 **Q. Are there statements in the Companies' testimony in the current rate cases**
7 **indicating that their attempted inclusion of Unamortized Cash Pension**
8 **Contributions is a new item that has not previously been authorized for rate**
9 **base inclusion in any prior rate case by the Commission?**

10 A. Yes. For example, the testimony of Ms. Larkin at Companies' Statement 6, page 14,
11 lines 4-7, singles out their attempted inclusion of Unamortized Cash Pension
12 Contributions as an exception to the methodology that Met-Ed and Penelec
13 employed in their 2006 base rate cases in Docket Nos. R-00061366 and R-
14 00061367.

15
16 **Q. Was the methodology that Met-Ed and Penelec employed in their 2006 base**
17 **rate cases for CWC in Docket Nos. R-00061366 and R-00061367 accepted by the**
18 **Commission?**

19 A. Only in part. In considerable part, such as the attempt by Met-Ed and Penelec in
20 those cases to include non-cash items, to include a return on equity component, to
21 fail to reflect the lag on the payment of interest expense on long-term debt, as
22 illustrative examples, all of which are discussed above, the Companies' methodology
23 was not accepted.

1

2 **Q. Do you agree with the Companies' proposed inclusion of a new item for**
3 **Unamortized Cash Pension Contributions in CWC?**

4 A. No. I have removed the amounts for Unamortized Cash Pension Contributions on
5 Schedule B-4, page 1, line 26, of Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and LA-
6 WP-1.

7

8 **Q. Please explain why those amounts should be removed.**

9 A. These amounts should be removed for several reasons. First, these amounts are not
10 part of the lead-lag study.

11 Second, there is no authorization that I could find in any Commission Order,
12 including the one in the last Met-Ed or Penelec rate cases, for including this item in
13 CWC.

14 Third, this item was not included in the Met-Ed or Penelec requested or in the
15 Commission authorized CWC in their last rate cases in Docket Nos. R-00061366 and
16 R-00061367.

17 Fourth, to the extent that the Companies' requested inclusion of Unamortized
18 Cash Pension Contributions in the current rate cases may be based in some respect
19 on the Companies' proposed use of a ten-year average of pension funding
20 contributions to determine a normalized pension expense in the last Met-Ed and
21 Penelec rate cases, which was accepted by the Commission, or the similar request
22 being made by the Companies in the current rate cases, that is not sufficient rationale
23 for creating a new rate base item. A normalized O&M expense allowance, such as

1 rate case expense or pensions, is not converted into a rate base investment. The use
2 of a multi-year period for an amortization or normalization for such items does not
3 result in the creation of new rate base balances that should earn a return. In Docket
4 Nos. R-00061366 and R-00061367, the references to pension funding in the prior
5 Met-Ed and Penelec rate case was for the purpose of deriving a normalized amount
6 of an operating expense, and, a review of the record in those cases reveals that this
7 did not encompass the creation of any new rate base inclusion in CWC for
8 unamortized pension funding amounts.

9 Fifth, there has been no showing by the Companies that pension expense for
10 Penn Power or West Penn has historically been similarly based on a ten-year average
11 of pension funding contributions. Consequently, there is no apparent historical
12 justification for imposing a new CWC component for Unamortized Cash Pension
13 Contributions on Penn Power or West Penn ratepayers.

14 Sixth, there is a general lack of support or convincing rationale for including
15 these large amounts in rate base for a new component of CWC that has apparently
16 never been authorized for rate base inclusion in the past for any of these four
17 utilities.

18
19 **Q. What adjustment have you reflected to remove these amounts from CWC?**

20 **A.** As shown on Schedule B-4, page 1, line 26, of Exhibits LA-ME-1, LA-PN-1, LA-
21 PP-1, and LA-WP-1, I have removed the amounts the Companies' have requested for
22 rate base inclusion, via CWC, for this item, as follows:

- 23 • \$30.177 million for Met-Ed;
- 24 • \$17.912 million for Penelec;

- \$5.125 million for Penn Power; and
- \$28.393 million for West Penn.

Q. What overall adjustments to cash working capital do you recommend for each utility?

A. As shown on Schedule B-4 of Exhibit LA-ME-1, I have determined Met-Ed's cash working capital requirement to be \$65.839 million. This is \$81.989 million less than Met-Ed's claim.

As shown on Schedule B-4 of Exhibit LA-PN-1, I have determined Penelec's cash working capital requirement to be \$60.843 million. This is \$63.999 million less than Penelec's filed claim.

As shown on Schedule B-4 of Exhibit LA-PP-1, I have determined Penn Power's cash working capital requirement to be \$13.410 million. This is \$14.226 million less than Penn Power's filed claim.

As shown on Schedule B-4 of Exhibit LA-WP-1, I have determined West Penn's cash working capital requirement to be \$55.688 million. This is \$61.392 million less than West Penn's filed claim.

B-5, Corrections to Remove Transmission Projects from Account 303, Miscellaneous Intangible Plant (Met-Ed and Penelec)

Q. Please explain the adjustment to remove from rate base the cost for a transmission construction project.

A. For Met-Ed, as shown on Exhibit LA-ME-1, Schedule B-5, this adjustment removes \$1.478 million from Met-Ed's rate base for Project ME-002582. The Companies'

1 response to I&E-ME-RB-29-D states that the original cost for Project ME-002582
2 for May 2015 through April 2016 is \$1,477,950. That response also states that:

3 Upon further review this is a transmission construction project
4 that should not be classified in FERC account 303. The
5 Company will reflect a reduction in its rate base request of
6 \$1,477,950 in wrap up.

7 This \$1.478 million has been removed from Met-Ed's electric distribution rate base.

8

9 **Q. Is there a related adjustment to Depreciation Expense?**

10 A. Yes. For Met-Ed, the related adjustment to Depreciation Expense is shown on
11 Exhibit LA-ME-1, Schedule C-9. The Commission authorized depreciation rate of
12 12.86% for Account 303, Miscellaneous Intangible Plant, was applied to the Plant
13 adjustment amount in order to derive the adjustment to reduce Depreciation Expense
14 by \$190,000.

15

16 **Q. Have you also adjusted FPFTY Accumulated Depreciation?**

17 A. Yes. I have reduced FPFTY Accumulated Depreciation by one-half of the
18 adjustment to FPFTY Depreciation Expense, as shown on Exhibit LA-ME-1,
19 Schedule B-5. The reduction to Accumulated Depreciation increases rate base.

20

21 **Q. Was there a similar adjustment for any of the other FirstEnergy utilities?**

22 A. Yes, there is a similar adjustment for Penelec. The Companies' response to I&E-PN-
23 RB-28-D states that, for Project PW-003994, original costs through March 2015
24 were \$11,715. That response also states that:

1 Upon further review this is a transmission construction project
2 that should not be classified in FERC account 303. The
3 Company will reflect a reduction in its rate base request of
4 \$11,715 in wrap up.

5 This \$11,715 should be removed from Penelec's electric distribution rate base.

6 FPFTY Plant is reduced by \$12,000 and accumulated depreciation by \$1,000,
7 as shown on Exhibit LA-PN-1, Schedule B-5, for a net rate base reduction of
8 \$11,000.

9
10 **B-6, Mobile Work Management System Corrections, Account 303, Miscellaneous**
11 **Intangible Plant (Met-Ed and Penelec)**

12 **Q. Please explain the adjustment to reflect a corrected cost estimate for Met-Ed**
13 **Project ME-700184.**

14 A. As explained in the Companies' response to I&E-ME-RB-29-D, the original cost of
15 \$14,141,364 was included in the FPFTY Met-Ed rate base for costs from May 2015
16 through April 2016. As further explained in that response:

17 The Company has revised its estimate for this project from
18 \$14,141,364 provided in the ME-RB-7D, Attachment A to
19 \$4,296,709. The Company will reflect a reduction in its rate
20 base request for Intangible Plant of \$9,844,655 in its wrap up
21 schedules.

22 The difference of \$9.845 million should be removed from Met-Ed's rate base, as
23 shown on Exhibit LA-ME-1, Schedule B-6.

24
25 **Q. Is there a related adjustment to Depreciation Expense?**

26 A. Yes. The related adjustment to Depreciation Expense is shown on Exhibit LA-ME-
27 1, Schedule C-10. The Commission authorized depreciation rate of 12.86% for
28 Account 303, Miscellaneous Intangible Plant, was applied to the Plant adjustment

1 amount in order to derive the adjustment to Depreciation Expense to reduce
2 Depreciation Expense by \$1.266 million.

3
4 **Q. Have you also adjusted FPFTY Accumulated Depreciation?**

5 A. Yes. I have reduced Met-Ed's FPFTY Accumulated Depreciation by one-half of the
6 adjustment to FPFTY Depreciation Expense, as shown on Exhibit LA-ME-1,
7 Schedule B-6. The reduction to Accumulated Depreciation increases rate base.

8
9 **Q. Is there a similar adjustment for any of the other FirstEnergy utilities?**

10 A. Yes. The Companies' response to I&E-PN-RB-29-D identified a work management
11 project for Penelec that was not included in its original request, the capital cost of
12 which is \$5.031 million, with an anticipated in-service date of December 31, 2015.
13 That response states further that: "The Company will reflect an increase in its rate
14 base request for Intangible Plant of \$5,031,300 in its wrap up schedules." The
15 response also states that the purpose of the project is for a Mobile Work
16 Management System.

17
18 **Q. How have you reflected this adjustment for Penelec?**

19 A. For Penelec, Exhibit LA-PN-1, Schedule B-6 shows the adjustment to add \$5.031
20 million for the Mobile Work Management System project, less the impact on
21 accumulated depreciation, estimated by taking one-half of the related adjustment to
22 depreciation expense. The net rate base increase is \$4.710 million.

1 **Q. Please explain the related adjustment to Depreciation Expense.**

2 A. For Penelec, the related adjustment to Depreciation Expense is shown on Exhibit
3 LA-PN-1, Schedule C-10. The Commission authorized depreciation rate of 12.79%
4 for Account 303, Miscellaneous Intangible Plant, was applied to the Plant adjustment
5 amount in order to derive the adjustment to Depreciation Expense, which is an
6 increase of \$644,000.

7

8 **B-7, ADIT – Impact of 2013 Change in Tax Accounting Method (All Four FE**
9 **Utilities)**

10 **Q. Did the Companies indicate that they had made some tax accounting method**
11 **changes?**

12 A. Yes. The Companies' response to OCA-I-47 described changes in tax accounting
13 methods that have been made by the Companies.

14

15 **Q. Were the Companies asked to quantify the impact of those tax accounting changes?**

16 A. Yes. OCA-XIII-4 (for Met-Ed and Penelec) and OCA-XIII-5 (for Penn Power and
17 West Penn) asked them to quantify and explain whether each of the changes in tax
18 accounting methods that were described in their response to OCA-I-47 are reflected
19 in the Companies' FPFTY ADIT.

20

21 **Q. What did those responses indicate?**

22 A. The Companies' responses to OCA-I-47 and OCA-XIII-4 for Met-Ed indicated that:

23 [T]he Company had 3 changes in accounting methods in the
24 requested period:

- 1 • In 2011, there was a change in method for repairs on
2 transmission and distribution asset;
- 3 • In 2013, there was a change in method for accrued
4 bonuses under the incentive compensation plans; and
- 5 • In 2013, there was a change in method for depreciation
6 on meters and transformers removed from service and
7 subsequently refurbished and installed.

8 The Company's FPFTY ADIT reflects the 2011 change in
9 accounting method, which is found on Met-Ed Exhibit RAD-
10 1, page 1, line 16. The Company's FPFTY ADIT does not
11 reflect the changes in accounting methods made on the 2013
12 return, filed in September 2014, because the entries to accrue
13 these amounts had not yet been made when FPFTY budget
14 was prepared.

15 The Companies' responses to the similar OCA data requests to the other
16 Companies were similar in terms of stating which tax accounting method changes
17 had and had not been reflected.

18
19 **Q. Are adjustments to FPFTY ADIT needed to reflect the impact on federal ADIT
20 for the 2013 tax accounting changes?**

21 A. Yes. The net impact of the 2013 tax accounting changes on FPFTY ADIT should be
22 reflected.

23
24 **Q. Please explain the adjustments to ADIT for each utility to reflect the impact of
25 these known 2013 tax accounting method changes.**

26 A. For Met-Ed, as shown on Exhibit LA-ME-1, Schedule B-7, adjusting Met-Ed's
27 FPFTY ADIT balance to reflect the impacts of these 2013 tax accounting changes
28 increases ADIT and decreases Met-Ed's FPFTY rate base by \$9.999 million.

1 For Penelec, as shown on Exhibit LA-PN-1, Schedule B-7, these 2013 tax
2 accounting method changes increase ADIT and decrease FPFTY rate base by \$9.541
3 million.

4 Similarly, for Penn Power, as shown on Exhibit LA-PP-1, Schedule B-7,
5 these 2013 tax accounting method changes increase ADIT and decrease FPFTY rate
6 base by \$1.585 million.

7 Finally, for West Penn, as shown on Exhibit LA-WP-1, Schedule B-7, these
8 2013 tax accounting method changes increase ADIT and decrease FPFTY rate base
9 by \$437,000.

10
11 **B-8, ADIT – Error Correction (Penelec)**

12 **Q. Please explain the adjustment to Penelec's rate base ADIT component for an**
13 **error correction.**

14 **A.** As shown on Exhibit LA-PN-1, Schedule B-8, a correction to Penelec's ADIT
15 balance, which increases ADIT and decreases Penelec's FPFTY rate base by \$2.296
16 million is needed. This correction is based on the Companies' response to OCA-PN-
17 XIII-3. Based on that response, which is included in Exhibit LA-2, FirstEnergy
18 agrees that a correction to Penelec's ADIT is needed. Exhibit LA-PN-1, Schedule B-
19 8 shows the calculation of the \$2.296 million adjustment.

20
21 **VI. ADJUSTMENTS TO OPERATING INCOME**

22 **Q. Please describe how you have summarized OCA's proposed adjustments to**
23 **operating income.**

1 A. On Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and LA-WP-1, Schedule C summarizes
2 the OCA's recommended net operating income. The Companies' overall proposed
3 adjusted net operating income is shown in column A of Schedule C. The OCA's
4 adjustments are shown in column B, and the OCA's adjusted results are shown in
5 column C. On Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and LA-WP-1, Schedule C.1
6 presents the OCA's recommended adjustments to test year revenues and expenses.
7 The impact on state and federal income taxes associated with each of the
8 recommended adjustments to operating income is also reflected on Schedule C.1.
9 The recommended adjustments to operating income are discussed below in the same
10 order as they appear on Schedule C.1.

11

12 **C-1, Consolidated Tax Savings (Met-Ed, Penelec, and Penn Power)**

13 **Q. Please explain the underlying rationale for adjusting federal income taxes to**
14 **reflect consolidated tax savings.**

15 A. The FirstEnergy utilities participate in the consolidated federal income tax return
16 filed by the FirstEnergy Corporation and its subsidiaries (the FirstEnergy System).
17 The filing of a consolidated income tax return results in utility corporations such as
18 the FirstEnergy System paying less income tax in a given year than would be paid if
19 each subsidiary filed a separate income tax return. This difference or consolidated
20 tax savings results from the ability to take advantage of the losses of the parent and
21 some unregulated subsidiaries on the consolidated basis by utilizing the income of
22 the regulated utilities and any other subsidiaries with taxable income to offset those
23 losses.

1

2 **Q. Did the FirstEnergy utilities include a consolidated tax savings adjustment in**
3 **their revenue requirement documentation in the current case?**

4 A. No, they did not.

5

6 **Q. Was a consolidated tax savings adjustment made in their prior rate cases?**

7 A. Yes. A consolidated tax savings adjustment was made in the prior rate cases of Met-
8 Ed and Penelec, Case Nos. R-00061366 and R-00061367.

9

10 **Q. Is consolidated tax information required to be provided in the minimum filing**
11 **requirements?**

12 A. Yes.

13

14 **Q. Did the FirstEnergy utilities provide such information?**

15 A. Yes. The FirstEnergy utilities provided consolidated federal income tax information
16 for the tax years 2010, 2011 and 2012 confidentially in Exhibit RAD-40.

17

18 **Q. Was consolidated tax information for tax year 2013 provided in response to**
19 **discovery?**

20 A. Yes. The Companies provided consolidated federal income tax information for tax
21 year 2013 in response to OCA-I-226 for each Company.¹⁰

22

¹⁰ Copies of the confidential responses to OCA-I-226 for each Company are attached to my testimony as a confidential exhibit (Exhibit LA-3).

1 **Q. Please explain how you are proposing to determine the Companies' share of the**
2 **savings realized by the FirstEnergy system as the result of filing a consolidated**
3 **tax return.**

4 A. I am proposing that the consolidated tax savings allocable to each Company be
5 determined utilizing the method approved by this Commission that has become
6 known as the modified effective tax rate method. Under this method, the first step is
7 to determine the consolidated tax savings that result from the losses of the
8 unregulated loss subsidiaries. These savings represent the difference between the
9 aggregate taxes that the members of the FirstEnergy System would have paid on
10 separate returns compared to the taxes paid on a consolidated basis. The second step
11 is to determine each of the four utilities' share of the savings based on taxable
12 income of each Company compared to the taxable income of all members of the
13 FirstEnergy System with positive taxable income.

14 The calculation of my consolidated tax savings adjustment is presented on
15 confidential Schedule C-1 of Exhibit LA-ME-1 for Met-Ed, confidential Schedule C-
16 1 of Exhibit LA-PN-1 for Penelec, and confidential Schedule C-1 of Exhibit LA-PP-
17 1 for Penn Power. Because there was no positive taxable income in any of the three
18 tax years 2011, 2012, or 2013 listed for West Penn, there is no consolidated tax
19 savings adjustment for West Penn in this case.

20 I am proposing to utilize the average consolidated tax savings for a three-year
21 period in order to normalize the results and smooth out any fluctuations from year to
22 year. The three years I have utilized for my calculation are the tax years 2011, 2012,

1 and 2013. The FirstEnergy consolidated federal income tax return for tax year 2013
2 was recently filed and is the most current consolidated tax return available.

3 As shown on Schedule C-1 of Exhibits LA-ME-1, LA-PN-1 and LA-PP-1:

- 4 • the consolidated tax savings adjustment for Met-Ed is \$15.091
5 million;
- 6 • the consolidated tax savings adjustment for Penelec is \$3.863 million;
7 and
- 8 • the consolidated tax savings adjustment for Penn Power is \$4.963
9 million.

10
11 **Q. Should a consolidated tax savings adjustment be made in the current rate**
12 **cases?**

13 A. Yes, due to the FirstEnergy utilities' participation in the FirstEnergy System
14 consolidated federal income tax return. Additionally, I am advised by Counsel that
15 in Pennsylvania a CTA is required by law.

16
17 **C-2, Miscellaneous Expenses (All Four FE Utilities)**

18 **Q. Please explain your adjustment to remove certain Miscellaneous Expenses.**

19 A. The Companies have included in FPFTY cost of service in their respective filings,
20 certain budgeted miscellaneous expenses that are discretionary and not necessary for
21 the provision of electric service. Specifically, examples of these questionable
22 miscellaneous expenses include the following descriptions:

- 23 a. Contingency for certain industry related regulatory, state and local
24 organization dues. The amounts included in the FPFTY for this line item

1 apply only to Met-Ed and Penelec, but are in addition to amounts budgeted
2 for specific organizations to which dues are paid.

3
4 b. Expenses budgeted for athletic events and tickets for such events, including
5 (1) community support of season opening block party; (2) corporate plan
6 hockey tickets; (3) holiday special group tickets; and (4) charitable support
7 organizations, advertising and promotion for customer programs (Penelec
8 only).

9
10 c. Athletic and employee associations, examples of which include (1)
11 FirstEnergy Men's Club; (2) FirstEnergy Women's Club; (3) JC&PL Retirees
12 Club; (4) Marion Area Men's Club; and (5) Perry Employee Association.¹¹

13 The Companies have not justified the expenditures associated with these
14 organizations and/or events, nor have the Companies' demonstrated that such costs
15 are needed for the provision of safe and reliable electric service. Given the
16 discretionary nature of these expenditures, it would be unreasonable to include them
17 in rates without some type of review for cost/benefit and appropriateness. Therefore,
18 as shown on Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and LA-WP-1, Schedule C-2, I
19 have reduced Miscellaneous Expense by \$19,578 for Met-Ed; \$67,573 for Penelec;
20 \$25,165 for Penn Power; and \$4,139 for West Penn.

21
22 **C-3, Amortization of Deferred Storm Damage Expense (Met-Ed and West Penn)**

23 **Q. Please explain OCA's adjustment for amortization of deferred storm damage**
24 **expense.**

25 A. This adjustment is shown on Schedule C-3 of Exhibit LA-ME-1 for Met-Ed and
26 Exhibit LA-WP-1 for West Penn. This adjustment is not applicable to Penelec or
27 Penn Power.

28

¹¹ For each of the four Companies, see the response to OCA Set I, No. 146.

1 **Q. Please explain the adjustment for Met-Ed.**

2 A. As shown on Exhibit LA-ME-1, Schedule C-3, for Met-Ed, this adjustment
3 addresses the cost for two storms: (1) Winter Storm Nika and (2) Hurricane Sandy.
4 The Commission's Orders in Docket Nos. P-2013-2351260 (May 22, 2014) and P-
5 2014-2412229 (July 16, 2013) state that: "we will direct the Company to
6 immediately begin expensing the deferred amounts in a reasonable amortization
7 schedule." In addition to the statement referenced above from the Commission
8 Order dated July 16, 2013 at Docket No. P-2013-2351260, the Commission stated in
9 part at page 6: "Metropolitan Edison Company shall claim the deferred expenses at
10 its first available opportunity," and "[t]his Order does not preclude Metropolitan
11 Edison Company from seeking recovery of the total amount of its deferred
12 expenses."

13 For purposes of applying this Commission directive, the same ten-year
14 amortization period that the Company listed in its response to OCA-ME-XVII-5 has
15 been used. The amortization has been applied starting in the month after the date of
16 the Commission's Order that addressed the storm cost deferral and contained the
17 directive to the Company to immediately begin expensing the deferred amounts in a
18 reasonable amortization schedule. In order to derive amounts of unamortized
19 deferred storm costs for the start of the FPFTY, the amortization of each storm was
20 continued through the start of the FPFTY, i.e., through May 1, 2015. Schedule C-3,
21 page 2, shows the number of months in the amortization period for each storm (1)
22 commencing from the month after the Commission's Order and (2) continuing

1 through April 30, 2015. Twelve months of amortization were applied for Winter
2 Storm Nika and 22 months were applied for Hurricane Sandy.

3 Applying the amortization through April 30, 2015 of \$1.328 million for
4 Winter Storm Nika to the deferred storm cost balance of \$13.275 million from the
5 response to OCA-ME-XVII-6 resulted in a beginning of FPFTY unamortized storm
6 balance of \$11.947 for Winter Storm Nika, as shown on Exhibit LA-ME-1, Schedule
7 C-3, column A, line 7. This beginning of FPFTY amount is amortized over the
8 remainder of the ten-year amortization period, for an annual amortization allowance
9 of \$1.328 million per year, as shown on Exhibit LA-ME-1, Schedule C-3, column A,
10 line 9.

11 For Winter Storm Nika, the monthly amortization of \$110,625 from the
12 Company's response to OCA-ME-XVII-6 times 12 months confirms the annual
13 amortization amount of \$1,327,500 that I have used on Exhibit LA-ME-1, Schedule
14 C-3, column A, line 9.

15 The difference between the annual amortization allowance of \$1.327 million
16 and Met-Ed's requested annual amount of \$4.442¹² million is \$3.115 million, as
17 shown on Exhibit LA-ME-1, Schedule C-3, column A, line 11. The Company's
18 requested prospective amortization for Winter Storm Nika is reduced by \$3.115
19 million.

20 Similarly, as shown on Exhibit LA-ME-1, Schedule C-3, column B, for
21 Hurricane Sandy, the beginning of FPFTY amount of \$17.556 million is amortized

¹² The \$4.442 million for Winter Storm Nika was calculated by dividing total deferred damage totaling \$13.327 million by 3 years as reflected on Met-Ed Exhibit RAD-2, Adjustment No. 9.

1 over the remainder of the ten-year amortization period, producing an annual
2 prospective amortization of \$2.150 million per year.

3 For Hurricane Sandy, the monthly amortization of \$179,146 from the
4 Company's response to OCA-ME-XVII-5 times 12 months confirms the annual
5 amortization amount of \$2,149,749 that I have used on Exhibit LA-ME-1, Schedule
6 C-3, column A, line 9.

7 The difference between the annual amortization allowance of \$2.150 million
8 and Met-Ed's requested annual amount of \$7.166 million is \$5.016 million, as shown
9 on Exhibit LA-ME-1, Schedule C-3, column B, line 11. The Company's requested
10 prospective amortization for Hurricane Sandy is reduced by \$5.016 million.

11 As shown on Exhibit LA-ME-1, Schedule C-3, column C, line 11, the
12 Company's combined requested prospective amortization for both storms, Winter
13 Storm Nika and Hurricane Sandy, is reduced by \$8.130 million.

14
15 **Q. Please explain the adjustment for West Penn.**

16 A. The adjustment for West Penn is shown on Exhibit LA-WP-1, Schedule C-3 and
17 addresses the amortization of deferred storm costs for a February 2010 Winter Storm
18 that was addressed by the Commission in its Order in Docket No. P-2010-2216111
19 (March 31, 2011). For purposes of applying this Commission directive, the ten-year
20 amortization period that was discussed in the Commission's Docket No. P-2010-
21 2216111 Order dated March 31, 2011 was used. Page 6 of that Order in Ordering
22 paragraph 1(c) specifically states that: "Upon entry of this Order, West Penn shall
23 begin expensing the deferred losses on a 10 year amortization schedule." In addition

1 to this statement from the Commission Order dated March 31, 2011 at Docket No. P-
2 2010-2216111, the Commission stated in part at page 6: “West Penn shall claim the
3 deferred losses at its first available opportunity.” Additionally, in its Order on
4 Reconsideration entered July 18, 2011 at Docket No. P-2010-2216111, the
5 Commission clarified at page 5: “West Penn will have the opportunity to make a
6 claim in a future rate case for recovery of all of its storm damage expense.”

7 Exhibit LA-WP-1, Schedule C-3, page 2, shows the monthly amortization
8 that West Penn provided in response to OCA-WP-XVII-3. I used that for the
9 amount of unamortized storm costs through April 30, 2016. As shown on Exhibit
10 LA-WP-1, Schedule C-3, page 1, amortization has been applied starting in the first
11 month after the date of the Commission's Order that addressed the storm cost
12 deferral and contained the directive to the Company to immediately begin expensing
13 the deferred amounts over the ten year amortization schedule. In order to derive
14 amounts of unamortized deferred storm costs for the start of the FPFTY, the
15 amortization of the cost of the February 2010 Winter Storm was continued through
16 the start of the FPFTY, i.e., through May 1, 2015. The Company's response to
17 OCA-WP-XVII-3 shows the entire amortization period for the February 2010 Winter
18 storm.

19 Applying the amortization through April 30, 2015 of \$6.186 million for the
20 February 2010 Winter Storm to the deferred storm cost balance of \$15.465 million
21 resulted in a beginning of FPFTY unamortized storm balance of \$9.279 million, as
22 shown on Exhibit LA-WP-1, Schedule C-3, column A, line 7. Of the ten year
23 amortization period stated on page 6 of Commission's Docket No. P-2010-2216111

1 Order dated March 31, 2011, approximately six years (72 months) remains as of
2 April 30, 2015.

3 This beginning of FPFTY amount is therefore amortized over the remaining
4 amortization period shown in the response to OCA-WP-XVII-3, for an annual
5 amortization allowance of \$1.546 million per year, as shown on Exhibit LA-ME-1,
6 Schedule C-3, line 9.

7 The monthly amortization of \$128,875 from the Company's response to
8 OCA-WP-XVII-3 times 12 months confirms the annual amortization amount of
9 \$1,546,495 that I have used on Exhibit LA-WP-1, Schedule C-3, column A, line 9.

10 The difference between the annual amortization allowance of \$1.546 million
11 and West Penn's requested annual amount of \$5.155 million is \$3.608 million, as
12 shown on Exhibit LA-WP-1, Schedule C-3, line 11. The Company's requested
13 prospective amortization for the 2010 Winter Storm is reduced by \$3.608 million.
14

15 **C-4, Amortization of Merger Storm Damage Deferral (Met-Ed and Penelec)**

16 **Q. Please explain OCA's adjustment for amortization of merger storm damage**
17 **deferral.**

18 **A.** This adjustment is show on Schedule C-4 of Exhibit LA-ME-1 for Met-Ed and
19 Exhibit LA-PN-1 for Penelec. This adjustment is not applicable to Penn Power or
20 West Penn.

21 The Joint Petition for Partial Settlement of the proceeding for approval of the
22 FirstEnergy/Allegheny Energy merger at Docket Nos. A-2010-2176520 and A-
23 2010-2176732 allowed the Company to defer non-capital storm expenses in excess

1 of 125% of the storm expenses included in base distribution case and seek future
2 recovery. The Company is seeking recovery of those expenses in the instant case.
3

4 **Q. Did FirstEnergy apply any amortization of the post-merger storm cost for Met-**
5 **Ed or Penelec for the period from cost deferral through May 1, 2015, the start**
6 **of the FPFTY?**

7 A. No. FirstEnergy did not apply any amortization to the post-merger storm cost for
8 Met-Ed or Penelec for the period from cost deferral through May 1, 2015.
9

10 **Q. Is it reasonable to not apply any amortization to the deferred post-merger**
11 **storm costs?**

12 A. No. The Commission's practice for major storm cost deferral has typically been to
13 allow deferral and to require the utility to immediately begin expensing the deferred
14 amounts in accordance with a reasonable amortization schedule. Just because the
15 settlement and Commission Order in Docket Nos. A-2010-2176520 and A- 2010-
16 2176732 did not specify the amortization period does not mean that a reasonable
17 amortization period should not be applied. Indeed, it could be considered
18 unreasonable to allow a storm cost deferral to be carried for several years without
19 recognizing reasonable amortization, especially during periods in which the utilities
20 were under no rate moratorium. That would be contrary to established Commission
21 practice for storm cost deferrals. It would also represent a form of piecemeal
22 ratemaking. Providing for indefinite deferral of a single cost between rate cases,
23 without any amortization, is not a reasonable ratemaking practice and should not be

1 allowed here. Reasonable amortization should be reflected for these deferred storm
2 costs through the start of the FPFTY, similar to the treatment for other deferred
3 storm costs per the Commission's established practice.

4
5 **Q. What was the end date of the rate moratorium for Met-Ed and Penelec that**
6 **resulted from the merger docket?**

7 A. The October 22, 2010 Joint Petition for Partial Settlement (“Joint Petition”) in
8 Docket Nos. A-2010-2176520 and A-2010-2176732 provided that Met-Ed, Penelec,
9 and Penn Power will not increase their distribution rates to be effective prior to
10 October 1, 2012. This is discussed at page 9, paragraph 16, of the Joint Petition
11 under “Rate Stay Outs and Credits”, and it is clear from the context that the storm
12 costs deferred for Met-Ed and Penelec are directly related to the rate moratorium:

13 **Met-Ed, Penelec and Penn Power will not increase their**
14 **distribution base rates to be effective prior to October 1,**
15 **2012. During the period of the rate freeze these companies**
16 **will defer, and the parties shall not object to future**
17 **recovery of, reasonable and prudently incurred storm**
18 **expenses that are in excess of 125% of those amounts of**
19 **storm expenses included in each of Met-Ed’s, and**
20 **Penelec’s most recent base distribution rate case; for Penn**
21 **Power the base amount shall be the 2006 to 2009 four-year**
22 **average of \$1.78 million. Met-Ed, Penelec or Penn Power**
23 **may seek base rate relief from the Commission for any change**
24 **greater than \$500,000 resulting from any regulatory or**
25 **government mandate or change in statutory tax provisions.**
26 **This stay-out shall not apply to any application for**
27 **extraordinary rate relief or transmission rate changes. If,**
28 **during the period of the rate stay out, facilities currently**
29 **included in transmission rates established by the Federal**
30 **Energy Regulatory Commission (“FERC”) are, as a result of**
31 **settled or contested transmission case decisions before FERC,**
32 **deemed by FERC to no longer constitute FERC jurisdictional**
33 **transmission facilities, Met-Ed, Penelec and Penn Power will**
34 **have the right to seek recovery of the cost of these distribution**

1 facilities in a Pennsylvania distribution rate proceeding, so
2 long as there is an adjustment to the transmission rates to
3 reflect the removal of the facilities from transmission rates.
4 During the period of the stay-out, if Met-Ed, Penelec or Penn
5 Power net distribution investment earns a Return on Equity
6 that exceeds 10.1% (calculation will include a pension
7 normalization adjustment consistent with that allowed at
8 Docket No. R-00061366 and Docket No. R-00061367), then
9 such company will credit its excess earnings over the
10 following 12 months to the customers of that company.

11 (Emphasis supplied.)

12 The Commission's February 24, 2011 Opinion and Order in the merger,
13 Docket Nos. A-2010-2176520 and A-2010-2176732 at pages 21-22 notes that "...
14 the settlement provisions provide that there will be no base rate increase for Met-Ed,
15 Penelec and Penn Power customers prior to October 1, 2012." The Commission
16 approved the merger, and the Met-Ed and Penelec storm cost deferrals, with this
17 specific base rate increase restriction.

18
19 **Q. What amortization period have you applied for the Met-Ed and Penelec merger**
20 **storm costs?**

21 A. As shown on Schedule C-4, page 2 of Exhibits LA-ME-1 and LA-PN-1, I have
22 applied a ten-year amortization period commencing with October 1, 2012. This date
23 for starting the amortization corresponds to the expiration of the rate increase
24 moratorium that had been imposed upon Met-Ed and Penelec in the merger.

25
26 **Q. Please explain the merger storm cost adjustment for Met-Ed.**

27 A. As shown on Exhibit LA-ME-1, Schedule C-4, for Met-Ed, this adjustment
28 addresses the cost for major storm cost deferral that was authorized in the
29 FirstEnergy-Allegheny merger.

1 As noted above, the Commission's practice for major storm cost deferral is
2 generally to authorize deferral and require the utility to immediately begin expensing
3 the deferred amounts in a reasonable amortization schedule. For purposes of
4 applying this Commission directive to the major storm costs addressed in this
5 adjustment, a ten-year amortization period has been used, commencing with October
6 1, 2012, as explained above. The amortization has been applied starting October
7 2012 and continues through and beyond the FPFTY. Exhibit LA-ME-1, Schedule C-
8 4, page 2, shows the amortization schedule for Met-Ed. The monthly amortization is
9 \$251,166.56.

10 As shown on Exhibit LA-ME-1, Schedule C-4, page 1, the annual
11 amortization in the FPFTY ending April 30, 2015 is \$3.014 million. Applying the
12 amortization through the start of the FPFTY of \$7.786 million to the total deferral of
13 \$30.140 million resulted in a beginning of FPFTY unamortized storm balance of
14 \$22.354 million. This is shown on Exhibit LA-ME-1, Schedule C-4, page 1, line 7.
15 This beginning of FPFTY amount is amortized over the remaining 89 months, for an
16 annual amortization allowance of \$3.014 million per year, as shown on Exhibit LA-
17 ME-1, Schedule C-4, page 1, line 9. The \$3.014 million annual amortization is also
18 the result of multiplying the monthly amortization of \$251,166.56 time 12 months,
19 as shown on Exhibit LA-ME-1, Schedule C-4, page 1, lines 12-14. The difference
20 between the annual amortization allowance of \$3.014 million and Met-Ed's
21 requested annual amount of \$10.047 million (which assumed no pre-FPFTY
22 amortization) is \$7.033 million, as shown on Exhibit LA-ME-1, Schedule C-4, page

1 1, line 11. Therefore, the Company's requested prospective major storm cost
2 amortization is reduced by \$7.033 million.

3
4 **Q. Please explain the merger storm cost adjustment for Penelec.**

5 A. As shown on Exhibit LA-PN-1, Schedule C-4, for Penelec, this adjustment addresses
6 the cost for major storm cost deferral that was authorized in the FirstEnergy-
7 Allegheny merger.

8 As noted above, the Commission's practice for major storm cost deferral is
9 generally to authorize deferral and require the utility to immediately begin expensing
10 the deferred amounts in a reasonable amortization schedule. For purposes of
11 applying this Commission directive to the major storm costs addressed in this
12 adjustment, a ten-year amortization period has been used. The amortization has been
13 applied starting in October 2012, which corresponds to the expiration of the rate
14 increase moratorium for Penelec that was specified in the merger docket, as
15 discussed above. Exhibit LA-PN-1, Schedule C-4, page 2, shows the of amortization
16 schedule.

17 As shown on Exhibit LA-PN-1, Schedule C-4, page 1, applying the
18 amortization through April 30, 2015 of \$3.305 million to the deferred storm cost
19 balance of \$12.795 million resulted in a beginning of FPFTY unamortized storm
20 balance of \$9.490 million. This is shown on Exhibit LA-PN-1, Schedule C-4, page
21 1, line 7. This beginning of FPFTY amount is amortized over the remaining 89
22 months, for an annual amortization allowance of \$1.280 million per year, as shown
23 on Exhibit LA-PN-1, Schedule C-4, page 1, line 9. The difference between the

1 annual amortization allowance of \$1.280 million and Penelec's requested annual
2 amount of \$4.265 million (which assumed no pre-FPPTY amortization) is \$2.986
3 million, as shown on Exhibit LA-PN-1, Schedule C-4, page 1, line 11. Therefore the
4 Company's requested prospective major storm amortization is reduced by \$2.986
5 million.

6
7 **C-5, Amortization Expense Related to Legacy Meters (All Four FE Utilities)**

8 **Q. Please explain OCA's adjustment for amortization expense related to legacy**
9 **meters.**

10 A. This adjustment, which is shown on Schedule C-5 of Exhibits LA-ME-1, LA-PN-1,
11 LA-PP-1, and LA-WP-1, amortizes the amount of legacy meter cost at the beginning
12 of the FPPTY over the remaining life of the legacy meters.

13
14 **Q. How is the estimated cost of removal and salvage treated in the calculation?**

15 A. The estimated net cost of removal is added to the beginning FPPTY balance of
16 legacy meter cost and is amortized over the remaining life of the legacy meters. This
17 treatment of the net cost of removal will help minimize the cost to ratepayers and is
18 in accordance with the Smart Meter Deployment Plan Recommended Decision in
19 Docket Nos. M-2013-2341990, M-2013-2341991, M-2013-2341993 and M-2013-
20 2341994, which stated at page 54 that:

21 ... the incremental cost of removal should be charged to the
22 regulatory asset account containing the remaining cost of the
23 retired Legacy Meters and be amortized over the remaining
24 depreciable lives of the metering assets along with the
25 remaining costs of those retired meters. The cost of removal
26 would then be recovered as part of the next base rate revenue

1 requirement for electric distribution service when the
2 regulatory asset is reflected in base rates.

3 The Commission's March 6, 2014 Decision in Docket Nos. M-2013-
4 2341990, M-2013-2341991, M-2013-2341993 and M-2013-2341994 agreed with the
5 OCA position on treatment of the net cost of removal, stating at page 40 that:

6 Upon our review of the record evidence we are in agreement
7 with the ALJ's recommendation that the incremental cost of
8 removal of the Legacy Meters should be charged to the
9 regulatory asset account containing the remaining cost of the
10 retired Legacy Meters and amortized over the remaining
11 depreciable lives of the metering assets along with the
12 remaining costs of those retired meters. We are persuaded by
13 the position of the OCA that this process will result in cost of
14 removal being treated symmetrically with salvage value and
15 will serve to smooth year-to-year variations in those costs. We
16 further agree with the ALJ's analysis that the Companies'
17 proposal of separating out the cost of removal from the
18 salvage value and depreciation does not minimize the cost to
19 consumers. We conclude that customers should not have the
20 delayed impact of the credit for the salvage value recovered
21 through the regulatory asset and the cost of removal of the
22 legacy meters charged immediately through the SMT-C rider.

23

24 **Q. What adjustments for each Company are you recommending for legacy
25 meters?**

26 A. For Met-Ed, as shown on Exhibit LA-ME-1, Schedule C-5, the remaining life of the
27 legacy meters was 20 years. Using a 20-year amortization, as opposed to the
28 Company's requested five years, and applying the amortization to the beginning of
29 FPFTY amount, reduces the Company's requested amortization expense by \$7.974
30 million.

31 For Penelec, as shown on Exhibit LA-PN-1, Schedule C-5, the remaining life
32 of the legacy meters was 20 years. Using a 20-year amortization, as opposed to the

1 Company's requested five years, and applying the amortization to the beginning of
2 FPPTY amount, reduces the Company's requested amortization expense by \$8.090
3 million.

4 For Penn Power, as shown on Exhibit LA-PP-1, Schedule C-5, the remaining
5 life of the legacy meters was 20 years. Using a 20-year amortization, as opposed to
6 the Company's requested five years, and applying the amortization to the beginning
7 of FPPTY amount, reduces the Company's requested amortization expense by
8 \$1.589 million.

9 Finally, for West Penn, as shown on Exhibit LA-WP-1, Schedule C-5, the
10 remaining life of the legacy meters was 31 years. Using a 31-year amortization, as
11 opposed to the Company's requested five years, and applying the amortization to the
12 beginning of FPPTY amount, reduces the Company's requested amortization
13 expense by \$4.827 million.

14
15 **Q. Is the amortization of the legacy meter costs over the remaining life of the**
16 **legacy meters consistent with the Order in the Smart Meter Plan dockets?**

17 **A.** Yes. For example, the Commission's June 5, 2014 Order in Docket No. M-2013-
18 2341990, states that:

19 FirstEnergy shall charge the incremental cost of removal of
20 Legacy Meters to the regulatory asset account containing the
21 remaining cost of the retired Legacy Meters and to amortize
22 the cost over the remaining depreciable lives of the metering
23 assets along with the remaining costs of those retired meters.

24 Similar statements are made in the Commission's June 5, 2014 Orders in
25 Docket Nos. M-2013-2341991, M-2013-2341993 and M-2013-2341994.

26

1 **C-6, Payroll Expense (All Four FE Utilities)**

2 **Q. Please explain the adjustment to FPFTY Payroll Expense.**

3 A. This adjustment is shown on Schedule C-6 of Exhibits LA-ME-1, LA-PN-1, LA-PP-
4 1, and LA-WP-1. It reflects payroll expense for the FPFTY and removes payroll
5 expense that is estimated to occur beyond the end of the FPFTY. Because the
6 FPFTY corresponds with the first year of new rates, it is appropriate to reflect the
7 amounts of payroll expense to be incurred in the FPFTY. The payroll projected to
8 occur beyond the end of the FPFTY will not be incurred during the first year of new
9 rates. Consequently, including it is a mismatch with the FPFTY. Expense projected
10 to be incurred beyond the end of the FPFTY is therefore being eliminated.

11
12 **Q. What specific payroll expenses have you adjusted?**

13 A. Consistent with the concept and principle of including expenses in the FPFTY that
14 will be incurred during the first year of new rates, and excluding expenses that will
15 not be incurred during the first year of new rates, I have removed pay increases that
16 are not anticipated to become effective during the first year of new rates, i.e.,
17 through April 30, 2016. I have also prorated pay increases that are becoming
18 effective during the first year of new rates to include the portion that would be
19 incurred during the FPFTY and to eliminate the portion that would be incurred
20 beyond the end of the FPFTY.

21
22 **Q. What adjustment does this produce for each utility?**

23 A. As shown on Schedule C-6 of Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and LA-WP-
24 1 respectively:

- Met-Ed's requested payroll expense is reduced by \$712,000.
- Penelec's requested payroll expense is reduced by \$584,000.
- Penn Power's requested payroll expense is reduced by \$100,000.
- West Penn's requested payroll expense is reduced by \$760,000.

C-7, Payroll Tax Expense (All Four FE Utilities)

Q. Please explain your adjustment to Payroll Tax Expense.

A. My recommended adjustment to each Company's payroll tax expense is made in conjunction with the recommended adjustment to payroll expense discussed in the previous section. The adjustment to payroll tax expense is shown on Schedule C-7 of Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and LA-WP-1. Based upon my recommendations to (1) eliminate the wage increases for the Companies' bargaining employees that are effective beyond the FPFTY,¹³ and (2) to prorate the wage increases for the Companies' non-bargaining employees as well as Service Company employees in which a portion of such wage increases will become effective during the FPFTY, I have reduced payroll tax expense by \$55,000 for Met-Ed, \$44,000 million for Penelec, \$8,000 million for Penn Power, and \$58,000 for West Penn, respectively.

C-8, Employee Benefits (All Four FE Utilities)

Q. Please explain your adjustment to Employee Benefits Expense.

¹³ This component of my payroll expense adjustment does not apply to Penn Power.

1 A. My recommended adjustments to Companies' employee benefits expense other than
2 Pensions and OPEBs¹⁴ is made in conjunction with my recommended adjustments to
3 payroll expense and are reflected on Schedule C-8 of Exhibits LA-ME-1, LA-PN-1,
4 LA-PP-1, and LA-WP-1. Based upon my recommendations to (1) eliminate the
5 wage increases for the Companies' bargaining employees that are effective beyond
6 the FPFTY, and (2) to prorate the wage increases for the Companies' non-bargaining
7 employees as well as Service Company employees in which a portion of such wage
8 increases will become effective within the FPFTY, I have reduced employee benefits
9 expense by \$88,000 for Met-Ed, \$48,000 for Penelec, \$5,000 for Penn Power and
10 \$72,000 for West Penn, respectively.

11

12 **C-9, Depreciation Expense - Remove Transmission Project from Account 303 (Met-**
13 **Ed and Penelec)**

14 **Q. Please explain the adjustment to Depreciation Expense to remove a**
15 **transmission project from Account 303.**

16 A. As described above, in conjunction with rate base adjustment in Schedule B-5, for
17 Met-Ed, the Companies' response to I&E-ME-RB-29-D states that the original cost
18 for Project ME-002582 for May 2015 through April 2016 is \$1,477,950. That
19 response also states that:

20 Upon further review this is a transmission construction project
21 that should not be classified in FERC account 303. The
22 Company will reflect a reduction in its rate base request of
23 \$1,477,950 in wrap up.

¹⁴ Separate adjustments for Pensions and OPEBs are discussed below in conjunction with adjustments C-14 and C-15, respectively.

1 This \$1.478 million should be removed from Met-Ed's electric distribution rate base,
2 which is done in adjustment B-5.

3 For Met-Ed, the related adjustment to Depreciation Expense is shown on
4 Exhibit LA-ME-1, Schedule C-9. The Commission authorized depreciation rate of
5 12.86% for Account 303, Miscellaneous Intangible Plant, was applied to the Plant
6 adjustment amount in order to derive the adjustment to reduce Depreciation Expense
7 by \$190,000.

8

9 **Q. Is there a similar adjustment to Depreciation Expense for Penelec?**

10 A. Yes. As shown on Exhibit LA-PN-1, Schedule C-9, Depreciation Expense for
11 Penelec is reduced by \$1,498.

12

13 **C-10, Depreciation Expense - Mobile Work Management System (Met-Ed and**
14 **Penelec)**

15 **Q. Please explain the adjustment to Met-Ed's Depreciation Expense related to a**
16 **corrected cost estimate for a Mobile Work Management System.**

17 A. As explained in the Companies' response to I&E-ME-RB-29-D, original cost of
18 \$14,141,364 was included in the FPFTY Met-Ed rate base for costs from May 2015
19 through April 2016. As further explained in that response:

20 The Company has revised its estimate for this project from
21 \$14,141,364 provided in the ME-RB-7D, Attachment A to
22 \$4,296,709. The Company will reflect a reduction in its rate
23 base request for Intangible Plant of \$9,844,655 in its wrap up
24 schedules.

25 The difference of \$9.845 million is being removed from Met-Ed's rate base,
26 as shown on Exhibit LA-ME-1, Schedule B-6. The related adjustment to Met-Ed's

1 Depreciation Expense is shown on Exhibit LA-ME-1, Schedule C-10. The
2 Commission authorized depreciation rate of 12.86% for Account 303, Miscellaneous
3 Intangible Plant, was applied to the Plant adjustment amount in order to derive the
4 adjustment to reduce Met-Ed's FPFTY Depreciation Expense by \$1.266 million.

5
6 **Q. Please explain the adjustment to Penelec's Depreciation Expense related to a**
7 **Mobile Work Management System.**

8 A. For Penelec, the related adjustment to Depreciation Expense is shown on Exhibit
9 LA-PN-1, Schedule C-10. The Commission authorized depreciation rate of 12.79%
10 for Account 303, Miscellaneous Intangible Plant, was applied to the Plant adjustment
11 amount in order to derive the adjustment to Depreciation Expense, which is an
12 increase of \$644,000.

13
14 **C-11, Vegetation Management (All Four FE Utilities)**

15 **Q. How much have the Companies included in their respective FPFTY filings for**
16 **vegetation management expense?**

17 A. According to the response to OCA-III-8,¹⁵ for the FPFTY ending April 30, 2016, the
18 Companies have included forecasted vegetation management expense in the amounts
19 of:

- 20 • \$11.307 million for Met-Ed:
- 21 • \$4.391 million for Penelec:
- 22 • \$3.626 million for Penn Power: and
- 23 • \$5.108 million for West Penn, respectively.

¹⁵ The reference to OCA-III-8 pertains to each of the four companies in this proceeding.

1
2
3
4
5
6

Q. How do these forecasted amounts for vegetation management expense compare to the amounts recorded during the HTY ended March 31, 2014?

A. As shown in the tables below, the Companies' forecasted FPFTY amounts for vegetation management expense reflect increases of 222% for Met-Ed, 76% for Penelec, 204% for Penn Power, and 6% for West Penn, respectively.

	Amount \$000's
Met-Ed	
FPFTY Vegetation Management Expense	\$ 11,307
HTY Vegetation Management Expense	\$ 3,513
Percentage Increase	222%

	Amount \$000's
Penelec	
FPFTY Vegetation Management Expense	\$ 4,391
HTY Vegetation Management Expense	\$ 2,492
Percentage Increase	76%

	Amount \$000's
Penn Power	
FPFTY Vegetation Management Expense	\$ 3,626
HTY Vegetation Management Expense	\$ 1,191
Percentage Increase	204%

	Amount \$000's
West Penn	
FPFTY Vegetation Management Expense	\$ 5,108
HTY Vegetation Management Expense	\$ 4,804
Percentage Increase	6%

7 Source: OCA-III-8 for all four companies
8

Q. Have the Companies provided an explanation of why, with the exception of West Penn, the forecasted FPFTY vegetation management costs are so much higher than the costs incurred during the HTY ended March 31, 2014?

A. For Met-Ed, Penelec and Penn Power, the response to OCA-XIV-16 stated in part:

The increase in vegetation management expense can be attributed to a shift from capitalizing vegetation management costs to recording vegetation management costs as a maintenance expense. The costs incurred for first time clearing, including the widening of the vertical and horizontal corridors and removal of trees from outside the corridor that are damaged or diseased are capitalized. This approach decreases the number of tree related incidences occurring within the lock out zone. The opportunity to capitalize costs reduces over time as first time clearing opportunities become fewer. As a result, the capital budget decreases and the

1 expense budget increases. Going forward, the Company will
2 continue to maintain cycle clearance as well as increase
3 expense associated with impacting regrowth on side trees and
4 brush control through the application of herbicides and
5 mowing. Finally, the future costs also account for an expected
6 increase in labor and equipment to perform the work.

7

8 **Q. What explanation was provided in OCA-XIV-16 for the forecasted FPFTY**
9 **increase in vegetation management expense as it relates to West Penn?**

10 A. As it relates to West Penn, the response to OCA-XIV-16 stated in part:

11 The PUC commitment for the HTY ended March 31, 2014 is
12 4,482 miles, which equals \$1,072/mile. The PUC
13 commitment for the FPFTY ended April 30, 2016 is 4,559
14 miles, which equals \$1,120/mile. The increase in per mile
15 cost over the two-year period relates to anticipated increased
16 costs for labor and equipment to perform the work.

17 In addition, Attachment A to the referenced response provided a listing of the
18 planned sections to trim, although no costs per section were provided.

19

20 **Q. Did Met-Ed and Penn Power provide similar information with respect to the**
21 **sections of vegetation to be trimmed, as well as the cost per mile of trimming**
22 **each such section?**

23 A. No. As it relates to the sections of vegetation to be trimmed and the associated cost
24 per mile for Met-Ed and Penn Power, the response to OCA-XIV-16 stated:

25 Details regarding sections to be trimmed are not currently
26 available. Circuits will be identified at a later date based on a
27 reliability focused prioritization.

28

29 **Q. Did Penelec provide information with respect to the sections of vegetation to be**
30 **trimmed, as well as the cost per mile of trimming each such section?**

1 A. Partially. Similar to West Penn, Penelec provided Attachment A with OCA-PN-
2 XIV-16 which listed the planned sections of vegetation to be trimmed. However,
3 Penelec stated that the cost to trim each section is not available.

4

5 **Q. OCA-XIV-16 also requested that each of the Companies' provide detailed**
6 **calculations which show how the FPFTY amounts for vegetation management**
7 **expense were derived. What details did the Companies provide in these**
8 **responses?**

9 A. The responses to OCA-ME-XIV-16, OCA-PN-XIV-16, OCA-PP-XIV-16 and OCA-
10 WP-XIV-16 did not provide the requested detailed calculations showing how the
11 FPFTY vegetation management expense amounts were derived. Based on the
12 foregoing, in my opinion, none of the four companies adequately substantiated the
13 proposed FPFTY vegetation management expenses. Accordingly, it is necessary to
14 adjust each Company's FPFTY vegetation expense amount.

15

16 **Q. Please explain your adjustment to Vegetation Management Expense.**

17 A. The Companies' vegetation management expenses are being adjusted to reflect
18 historical three-year average vegetation management expense.¹⁶ A recent three-year
19 average is used to produce a normalized amount for the FPFTY. I have reduced
20 vegetation management expense for each of the utilities by the amounts of:

- 21 • \$7.081 million for Met-Ed, as shown on Exhibit LA-ME-1, Schedule C-11;
- 22 • \$1.526 million for Penelec as shown on Exhibit LA-PN-1, Schedule C-11; and
- 23 • \$2.948 million for Penn Power, as shown on Exhibit LA-PP-1, Schedule C-11.

¹⁶ The three-year historical average is based on calendar years 2011, 2012 and 2013.

1 In addition, as shown on Schedule C-11 on Exhibit LA-WP-1, my
2 recommended adjustment results in an increase of \$695,000 to West Penn's proposed
3 vegetation management expense.
4

5 **C-12, Rate Case Expense (All Four FE Utilities)**

6 **Q. Please explain the Companies' claim for Rate Case Expense in the FPFTY**
7 **ending April 30, 2016.**

8 A. As shown on each Company's Exhibit RAD-23, Met-Ed, Penelec, Penn Power and
9 West Penn have budgeted the following amounts for its claimed rate case expense:

Rate Case Expense - \$000's				
Description	Met-Ed	Penelec	Penn Power	West Penn
Legal Expenses	\$ 275	\$ 289	\$ 80	\$ 356
Expert Witnesses	\$ 33	\$ 35	\$ 10	\$ 42
Other	\$ 187	\$ 197	\$ 54	\$ 242
Total	\$ 495	\$ 521	\$ 144	\$ 640

10 Source: Exhibit RAD-23
11

12 **Q. Over what period are the Companies proposing to recover the claimed amounts**
13 **for rate case expense reflected in the table above?**

14 A. As shown on each Company's Exhibit RAD-2, Adjustment No. 7, Met-Ed, Penelec,
15 Penn Power and West Penn are proposing to recover the claimed amounts for rate
16 case expense over a two-year period.
17

18 **Q. What justification do the Companies' give for proposing to normalize claimed**
19 **rate case expense over a two-year period?**

20 A. In response to OCA-I-120(d), Met-Ed stated the following:

1 As Met-Ed transitions from managing its operations and
2 maintenance ("O&M") expenses and plant investments under
3 a constant revenue stream, i.e., infrequent base rate cases, to a
4 Company that invests substantially in utility plant in service
5 and O&M to improve its infrastructure and reliability, it
6 would appear that Met-Ed will need to seek periodic base rate
7 cases to keep its rate of return at adequate levels going
8 forward. The estimate of approximately two years would
9 enable the Company time between base rate cases to examine
10 the outcome and successfully manage its cash needs on an
11 ongoing basis.¹⁷

12
13 **Q. Do you agree with the Companies' proposed two-year recovery period for rate**
14 **case expense?**

15 A. No, I do not. The issue of a reasonable and realistic normalization period for rate
16 case expense was addressed in Met-Ed's and Penelec's last base rate cases in Docket
17 Nos. R-00061366 and R-00061367. In those proceedings, Met-Ed and Penelec had
18 proposed a three-year recovery period for rate case expense. The Commission's
19 Final Order dated January 11, 2007 stated in part that:

20 . . . rate caps prevented a rate case filing in the last decade;
21 however, a review of the filing frequency before the
22 implementation of the rate caps reveals that the Companies
23 had unusually long intervals between rate case filings. For
24 example, ME's most recent rate cases were filed in 1984 and
25 1992 and PN's most recent rate case was filed in 1984.
26 Although the Competition Act established the rate caps,
27 nothing prevented the Companies from filing rate cases on a
28 regular basis prior to 1996. Although it is convenient to use
29 the rate caps as a justification for an expedited recovery
30 period, **a three year recovery period is unwarranted given**
31 **ME's and PN's history of long stay outs between rate case**
32 **filings.**

33 **Second, the Companies assertion that there is a "greater**
34 **likelihood" of more frequent filings now that the rate caps**
35 **have expired is merely a statement of future intentions,**

¹⁷ Similar responses were provided for Penelec, Penn Power and West Penn.

1 **which is highly speculative. The Commission relies on**
2 **filing history because that history is the most reliable**
3 **barometer of when future rate cases will be filed. The**
4 **filing history of MEPN does not support a three year filing**
5 **cycle. The Companies' request to ignore those facts and**
6 **instead rely on unpredictable future intentions must be**
7 **rejected.**

8 Finally, the Companies' reliance on the PPL case is wholly
9 irrelevant because **normalization periods are specific to**
10 **each company and are based on the historic frequency of**
11 **base rate case filings.**

12 (Emphasis supplied.)

13 As noted above, the Commission's Final Order in the above referenced prior
14 dockets was dated January 11, 2007, or over seven years from August 4, 2014, i.e.,
15 from the filing date of the Companies' rate case filings in the current proceedings.
16 In addition, Penn Power's last rate case filing was in Docket No. R-870732, filed
17 August 5, 1987 and with the Final Order issued May 3, 1988. Penn Power's current
18 distribution rates were established in Docket No. R-00974149 with the Final Order
19 issued July 22, 1998. Moreover, West Penn's last rate case filing was in Docket No.
20 R-00942986 with the Final Order issued December 29, 1994. West Penn's current
21 distribution rates were established in Docket No. R-00973981 with the Final Order
22 issued November 19, 1998. Thus, it appears that the Companies' trend of relatively
23 infrequent rate case filings has not changed. As such, a two-year normalization
24 period for recovery of rate case expense in the current proceedings is unwarranted
25 and should be rejected.

26
27 **Q. What normalization period do you recommend for the recovery of the**
28 **Companies' claimed rate case expense in the current proceedings?**

1 A. I recommend that each Company's claimed rate case expense be normalized over a
2 period of five years, which is more representative of the historical long periods
3 between rate cases and is the period used by the Commission in the most recent Met-
4 Ed and Penelec rate cases, Docket Nos. R-00061366 and R-00061367. Therefore, I
5 have reduced rate case expense by:

- 6 • \$149,000 for Met-Ed, as shown on Exhibit LA-ME-1, Schedule C-12;
- 7 • \$157,000 for Penelec, as shown on Exhibit LA-PN-1, Schedule C-12;
- 8 • \$43,000 for Penn Power, as shown on Exhibit LA-PP-1, Schedule C-12; and
- 9 • \$192,000 for West Penn, as shown on Exhibit LA-WP-1, Schedule C-12,
10 respectively.

11

12 **C-13, Interest Synchronization (All Four FE Utilities)**

13 **Q. Please explain OCA Adjustment C-13 for interest synchronization.**

14 A. The interest synchronization adjustment applies the weighted cost of debt to the
15 adjusted rate base to calculate the amount of interest deduction to be reflected in the
16 calculation of test year income tax expense. After adjustments, the OCA's proposed
17 rate base differs from the rate base used in the Companies' filing. This results in a
18 different amount of synchronized interest expense included in the income tax
19 calculation. The calculation of the interest synchronization adjustment is shown on
20 Schedule C-13 of Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and LA-WP-1. This
21 adjustment increases the combined state and federal income tax expense for each
22 Company by the amounts shown on Schedule C-13. Each Company's combined net
23 operating income is reduced by the amount of the net increase to income tax
24 expense.

1

2 **C-14, Pension Expense (All Four FE Utilities)**

3 **Q. How have the FirstEnergy Companies proposed to derive their requested**
4 **allowance for pension expense in the current rate cases?**

5 A. The Companies have proposed to base pension expense on a ten-year average of
6 cash funding contributions.

7
8 **Q. What is their basis for using a ten-year average?**

9 A. This request appears to be based on the allowance for pension costs in the last Met-
10 Ed and Penelec rate cases, Docket Nos. R-00061366 and R-00061367.

11
12 **Q. Do you agree with the Companies' proposed pension expense?**

13 A. No. For several reasons, which I will explain in this section of my testimony, I do
14 not. For the reasons explained herein, I am recommending that the utilities' pension
15 cost in these rate cases be based on SFAS 87 accruals.

16
17 **Q. Was the use of a ten year average of contributions the Companies' initially**
18 **recommended basis for pension cost recognition in those cases?**

19 A. No, it was not. Based on a review of testimony from Docket Nos. R-00061366 and
20 R-00061367, it appears that the initial recommendations of Met-Ed and Penelec in
21 those cases for pension expense was to use the service cost component of Statement
22 of Financial Accounting Standards No. 87 ("SFAS 87").

23

1 **Q. Does the Order in Docket Nos. R-00061366 and R-00061367 concerning the**
2 **treatment of pension costs apply to the other two utilities, i.e., to Penn Power or**
3 **West Penn?**

4 A. I am advised by OCA counsel that it does not. Since the Order in Docket Nos. R-
5 00061366 and R-00061367 concerning the treatment of pension costs was in the
6 context of Met-Ed and Penelec rate cases, it does not apply to the other two utilities,
7 i.e., to Penn Power or West Penn.

8

9 **Q. Should the use of a ten-year average of pension funding contributions have any**
10 **wider application, beyond the Met-Ed and Penelec rate cases that were**
11 **addressed in Docket Nos. R-00061366 and R-00061367?**

12 A. No. That recognition of Met-Ed and Penelec pension expense in those cases appears
13 to be the result of a fall-back position of Met-Ed and Penelec that was not even
14 presented with the utilities' initial application and direct testimony. Moreover, it
15 does not appear to be the result of a comprehensive analysis of pension costs. Nor
16 does it appear to be a regulatory practice that should be applied on a wider basis
17 beyond its narrow use in establishing the revenue requirements in those particular
18 prior Met-Ed and Penelec rate cases that were addressed in Docket Nos. R-00061366
19 and R-00061367. It appears that a ten-year average was not used for those utilities
20 prior to those cases. Its use in those cases should be confined to only those cases. A
21 ten-year average should not be expanded to other utilities or even used in subsequent
22 rate cases of Met-Ed or Penelec. There are good reasons why it should not be used

1 in subsequent rate cases, such as the current rate case, for those two utilities (Met-Ed
2 or Penelec) or for others.

3
4 **Q. Based on your experience, is the use of a ten-year average of funding
5 contributions for pensions as the basis for ratemaking recognition of utility
6 pension expense common in utility ratemaking?**

7 A. No, it is not common. In fact, I would characterize it as an extreme aberration.
8 Recognition of pension costs for ratemaking for most utilities is based on some
9 variant of SFAS 87 cost. In the few states I am aware of where cash funding
10 contributions are used, and a multi-year average is used, the period for multi-year
11 averaging is typically much shorter than ten years. For example, when cash funding
12 contributions have been used as the basis for pension expense recognition in
13 Washington State in cases in which I have direct knowledge, a four-year period was
14 used. A ten-year period reaches too far into the past and does not reflect current or
15 going forward conditions.

16
17 **Q. Are there other concerns with using a lengthy backward looking historical
18 period of cash funding contributions as the basis for ratemaking recognition of
19 utility pension cost?**

20 A. Yes. It is inconsistent with generally accepted accounting principles (“GAAP”),
21 and could result in overstating the utility’s pension costs for an extended period.
22 Additionally, as I will describe in additional detail below, utility management has
23 considerable discretion in how defined benefit pensions are funded. Thus, historical

1 funding amounts can reflect the impact of management decisions on when and how
2 much to fund, subject to minimum required funding and maximum tax-deductible
3 funding. Using a ten-year average of historical funding contributions is also
4 inconsistent with how the FE utilities budget for pension cost. To understand these
5 concerns, a review of defined benefit pension plans, and the related accounting and
6 funding should be helpful. I will discuss those aspects and then explain the
7 recommended adjustment.

8
9 **Q. What is a defined benefit pension plan?**

10 A. There are two general types of pension plans: (1) defined benefit pension plans and
11 (2) defined contribution plans. In a defined benefit pension plan employees accrue
12 benefits during their years of service and receive specified benefits in the form of an
13 annuity or lump sum, after they retire, and the employer bears the risk of investment
14 market fluctuations and assuring that there are sufficient funds available to pay the
15 pensioners at the specified level. In contrast, in defined contribution pension plans,
16 such as 401(k) savings plans or money purchase pension plans, employees and
17 employers make contributions at a predefined level and employees bear the risk of
18 investment market fluctuations in the value of their investments.

19
20 **Q. Are there utilities requesting pension cost for their defined benefit pension**
21 **plans?**

22 A. Yes. The pension cost issue in the current cases relates to the cost of providing
23 retirement benefits in a defined benefit pension plan.

2 **Q. What is SFAS 87?**

3 A. SFAS 87 is an accounting standard promulgated by the Financial Accounting
4 Standards Board (“FASB”) in December 1985 relating to employer’s accounting for
5 pensions. It has been codified in the Accounting Standards Codification (“ASC”) as
6 ASC 715. For purposes of this testimony, I will generally refer to this as FAS 87
7 rather than ASC 715, consistent with how the Companies have presented their
8 discussion.

9

10 **Q. What is net periodic pension cost (“NPPC”)?**

11 A. As it pertains to a defined benefit pension plan, NPPC is the amount recognized in
12 an employer's financial statement as the cost of the pension plan for the period. Put
13 another way, the NPPC is the annual accounting expense or income a company must
14 recognize in their income statement, and direct adjustments to the plan sponsor’s
15 balance sheet, if applicable.

16

17 **Q. What are the components of net periodic pension cost under FAS 87?**

- 18 A. Under FAS 87, the NPPC is the sum of the following components:
- 19 • **Service cost**, which is the value of the benefits earned, or accrued, during the
20 current year based on the applicable benefit formula for each participant.
 - 21 • **Interest cost**, which represents the interest on the pension plan liability (i.e.,
22 Projected Benefit Obligation, or "PBO") for the year. This amount increases
23 pension cost and reflects the passage of time or the time value of money on the
24 PBO.
 - 25 • **Expected return on assets for the year**, which reduces pension cost and is
26 based on applying an expected rate of return to pension trust assets. Differences

1 between the actual return on assets and the expected return on assets represent an
2 actuarial gain or loss that will be recognized in future pension cost.

- 3 • **Amortizations of unrecognized costs and gains**, which can include
4 amortizations related to changes in liability due to plan changes, changes in
5 actuarial assumptions used to value plan liabilities, differences between expected
6 and actual asset returns, and/or experienced gains or losses to be recognized over
7 time and subject to amortization. The amortization period is not to exceed the
8 average future lifetime of plan participants. Prior Service Cost amortization is
9 generally the cost of retroactive benefits granted in a plan amendment.
10 Retroactively increasing benefits increases the PBO and prior service cost at the
11 date of amendment and vice-versa. The increased (or decreased) cost is
12 amortized as a component of net periodic pension cost. Amortization can be done
13 on straight line basis that amortizes cost over the average remaining service life
14 of the active employees. Actuarial gains and losses occur due to changes in
15 actuarial assumptions. Gains decrease and losses increase the pension cost. There
16 are two components of gains/losses: (1) the current period difference which is
17 the difference between actual and expected return (expected rate of return on
18 plan assets times the market related value of plan assets) and (2) the amortization
19 of the unrecognized gain/loss for previous periods. In amortizing unrecognized
20 gains or losses, a 10% corridor is allowed to be used in which only those gains or
21 losses in excess of the greater of 10% of the PBO or the market-related value of
22 assets are subject to amortization.

23
24 **Q. When FAS 87 was initially adopted for financial reporting purposes, was there**
25 **also a transitional component of the NPPC?**

26 **A.** Yes. When FAS 87 was promulgated by the FASB in December 1985, it also
27 included a component of NPPC for Amortization of Transition Benefit Asset
28 (decrease) or Obligation/Liability (increase) to pension cost. The Transition Benefit
29 (or Obligation) amount was based on the funded status of the defined benefit pension
30 plan when FAS 87 was initially adopted for financial reporting purposes. The
31 employer recorded the amortization of the Transition Benefit Obligation (“TBO”)
32 over average remaining service of plan employees, or over a 15-year period if the
33 service period was less than 15 years. Most companies, and it is believed that all of
34 the FE utilities participating in the current case, are now beyond the TBO

1 amortization periods, so TBO amortization would generally no longer be a
2 component of a utility's NPPC.

3
4 **Q. Please describe the events or circumstances that can result in a company
5 recording a pension asset.**

6 A. As noted above, in December 1985, the FASB issued FAS 87. FAS 87 provided
7 guidance as to how companies would recognize costs associated with defined benefit
8 pension plans for financial statement reporting purposes, effective for fiscal years
9 beginning after December 15, 1986. Prior to the issuance of FAS 87, the amount of
10 pension costs recorded by a company for financial statement purposes was generally
11 equal to the level of contributions actually made into the pension trust fund.¹⁸ As a
12 result of FAS 87, the FASB determined that pension costs reported for financial
13 statements purposes would not automatically be equal to the pension trust fund
14 contribution, breaking the historical linkage between financial reporting of net
15 periodic pension costs (expense and capital)¹⁹ and pension funding contributions.

16 If the pension funding contributions exceeded the pension costs recorded for
17 financial statement purposes,²⁰ FAS 87 required the difference to be recorded in a
18 balance sheet account as a pension asset. If the contribution to the pension fund was

¹⁸ The pension fund is separate from the utility's financial statements. The monies in the pension fund are held by the pension trustee. The utility's contributions (i.e., monies deposited) to the pension fund are invested by the pension trustee to ensure that the fund balances are sufficient to pay future pension obligations to the utility's employees.

¹⁹ The full amount of NPPC determined by the Company's actuary is initially recorded in expense Account No. 926, Employee Pensions and Benefits. The portion of NPPC that is capitalized to plant or billed to others is recorded in a contra-expense to Account No. 926, Employee Benefits Transfer. This latter account recognizes that a pro-rata portion of employee benefits are attributable to the labor costs that are charged to capitalized construction projects and eventually to utility plant in service.

²⁰ Pension costs recorded for financial statement purposes pursuant to FAS 87 are also referred to as Net Periodic Pension Cost or NPPC.

1 less than the recorded pension cost, the company would record a pension obligation
2 or liability. In a period when a company had pension income (i.e., a negative
3 NPPC), and made no pension trust funding contributions, this type of situation could
4 also lead to the company recording a pension asset. In sum, FAS 87 required
5 companies to record either a pension asset or pension liability for the difference
6 between accrual basis pension costs that are recorded for financial statement
7 purposes and the amount of any contributions to the pension fund. As indicated
8 previously, this accounting is commonly referred to as accrual accounting for NPPC.
9

10 **Q. Does FAS 87 dictate a particular ratemaking treatment?**

11 A. No. FAS 87 provides accounting guidance with respect to the financial accounting
12 disclosure of pension costs, related assets and liabilities. FAS 87 neither prescribes
13 nor imposes any regulatory guidance or authoritative ratemaking treatment for the
14 NPPC or for the prepaid pension asset or pension liability. FAS 87 sets forth the
15 required framework for all publicly traded companies to quantify and record net
16 periodic pension costs. Neither the actual FAS 87 NPPC accruals nor actual pension
17 contributions should be interpreted as costs recovered from, or benefits provided to
18 ratepayers, particularly without any evidence to substantiate such claims.
19

20 **Q. What is the usual source for the amounts recorded by a company on its books
21 for its NPPC for a defined benefit pension plan?**

22 A. It is typically an actuarial report. Each year, with assistance from its actuarial
23 consultants, the employer providing the defined benefit pension plan would record a

1 journal entry in its accounting records in order to accrue the NPPC pursuant to FAS
2 87. The actuarial consultants may also provide assistance in quantifying the range in
3 pension contributions that are required or permitted under existing regulations.²¹
4

5 **Q. How have the minimum funding levels for a defined benefit pension plan**
6 **generally been determined?**

7 A. Prior to 2008, the minimum required funding requirements were specified in
8 ERISA.²² ERISA is a federal law that established minimum standards for pension
9 plans in private industry and provides for extensive rules on the federal income tax
10 effects of transactions associated with employee benefit plans. ERISA was enacted
11 to protect the interests of employee benefit plan participants and their beneficiaries
12 by:

- 13 • Requiring the disclosure of financial and other information concerning
 - 14 the plan to beneficiaries;
 - 15 • Establishing standards of conduct for plan fiduciaries;
 - 16 • Providing for appropriate remedies and access to the federal courts.
- 17

18 **Q. Does ERISA require that pensions be provided in a defined benefit plan?**

19 A. No. ERISA does not require employers to establish pension plans. Likewise, as a
20 general rule, ERISA does not require that pension plans provide a minimum level of
21 benefits. Instead, ERISA regulates the operation of a pension plan once it has been
22 established. Under ERISA, pension plans must provide for vesting of employees'
23 pension benefits after a specified minimum number of years. ERISA requires that the

²¹ This information may include minimum required funding contributions and the maximum tax-deductible contributions.

²² Pub.L. 93-406, 88 Stat. 829, enacted September 2, 1974, codified in part at 29 U.S.C. ch. 18.

1 employers who sponsor plans satisfy certain minimum funding requirements. ERISA
2 also regulates the manner in which a pension plan may pay benefits. For example, a
3 defined benefit plan must pay a married participant's pension as a "joint-and-survivor
4 annuity" that provides continuing benefits to the surviving spouse unless both the
5 participant and the spouse waive the survivor coverage.

6
7 **Q. How has ERISA helped assure that defined benefit pension plans would have**
8 **sufficient assets from which to pay benefits?**

9 A. Among other things, ERISA established the Pension Benefit Guaranty Corporation
10 ("PBG") to provide coverage in the event that a terminated defined benefit pension
11 plan does not have sufficient assets to provide the benefits earned by participants.
12 Later amendments to ERISA require an employer who withdraws from participation
13 in a multi-employer pension plan with insufficient assets to pay all participants'
14 vested benefits to contribute the pro rata share of the plan's unfunded vested benefits
15 liability.

16 Under ERISA, minimum funding requirements were also established for
17 defined benefit plans.²³ Under ERISA, a defined benefit pension plan maintained a
18 "funding standard account," which was charged annually for the cost of benefits
19 earned during the year and credited for employer contributions. Increases in the
20 plan's liabilities due to benefit improvements, changes in actuarial assumptions, and
21 any other reasons were amortized and charged to the account. Decreases in the
22 plan's liabilities were amortized and credited to the account. Every year, the

²³ By their nature, defined contribution plans are always fully funded, even if the employee has not yet become vested in the employer contributions.

1 employer was required to contribute the amount necessary to keep the funding
2 standard account from falling below zero at year-end. Minimum annual funding
3 requirements are therefore sometimes referred to as the ERISA funding requirement
4 or the ERISA minimum.

5
6 **Q. Are the minimum funding requirements for a defined benefit pension plan now**
7 **also impacted by another act?**

8 A. Yes. The Pension Protection Act of 2006 (“PPA”) included additional funding
9 requirements to improve the benefit security provided by defined benefit pension
10 plans. The PPA redefined minimum required cash funding requirements for defined
11 benefit pension plans for 2008 and beyond.

12
13 **Q. Please describe the general funding requirements for a defined benefit pension**
14 **plan under the PPA.**

15 A. In 2008, when the PPA funding rules went into effect, single-employer defined
16 benefit pension plans no longer maintain funding standard accounts. The funding
17 requirement under PPA is basically that a plan must stay fully funded (that is, its
18 assets must equal or exceed its liabilities). If a plan is fully funded, the minimum
19 required contribution is the cost of benefits earned during the year. If a plan is not
20 fully funded, the contribution also includes the amount necessary to amortize over
21 seven years the difference between its liabilities and its assets. Stricter rules apply to
22 severely underfunded plans (called “at-risk status”).

1 The PPA has different funding requirements for multi-employer pension
2 plans, which preserve most of the pre-PPA funding rules including the funding
3 standard account. Under the PPA, increases and decreases in the plan's liabilities
4 will be amortized, but the amortization period for benefit improvements adopted
5 after 2007 will be shortened. As with single-employer plans, multi-employer pension
6 plans that are significantly underfunded are subject to restrictions. The restrictions,
7 which may limit the plan's ability to improve benefits or require the plan to reduce
8 employees' benefits, vary depending whether a pension plan's funding status is
9 termed "endangered," "seriously endangered," or "critical." The restrictions
10 accompanying each deficient funding status are progressively more severe as
11 funding status worsens.

12 In general, the PPA requires a sponsor of a defined benefit pension plan to
13 contribute into the plan annually an amount equal to: (1) the benefits being earned
14 for the year, plus (2) a seven-year amortization of the amount the plan is
15 underfunded. The seven-year amortization base is established each year based on
16 the difference between the funded status of the plan and the value of the previous
17 seven-year amortization bases that still exist. Once the plan becomes fully funded,
18 all amortization bases are eliminated and the required contribution simply becomes
19 the benefits being earned for the year. This is sometimes referred to as the "normal
20 cost." If the plan becomes overfunded by more than the benefits being earned for
21 the year, no new funding contribution is required for that year. Contributions are
22 typically to be made on a quarterly basis. More frequent funding (e.g., monthly) is

1 not prohibited. A final contribution for the year is generally allowed to be made up
2 to eight and one-half months after the end of the plan year.

3

4 **Q. Please explain the concept of the maximum tax deductible contribution for**
5 **funding of a defined benefit pension plan.**

6 A. The Internal Revenue Code contains provisions limiting the maximum tax deduction
7 for contributions made to fund various types of retirement benefits, including
8 defined benefit pension plans.

9

10 **Q. Can you provide an explanation of how the maximum tax deductible**
11 **contribution for a defined benefit pension plan is generally determined?**

12 A. Generally, an actuary will provide the plan sponsor with information on both (1) the
13 minimum funding obligation (representing the lowest amount needed to meet the
14 minimum funding obligation, as discussed above) and (2) the maximum tax-
15 deductible funding contribution. The latter generally involves actuarial calculations,
16 which can be quite complex, to derive a “full funding limitation.”

17 Basically, two provisions determine the maximum amount an employer can
18 contribute and take as a deduction to a qualified pension plan in any one taxable
19 year.

20 The first of these rules permits a deduction for a contribution that will
21 provide, for all employees participating in the plan, the unfunded cost of their past
22 and current service credits distributed as a level amount or as a level percentage of
23 compensation over the remaining future service of each such employee. If this rule

1 is followed, and if the remaining unfunded cost for any three individuals is more
2 than 50 percent of the total unfunded cost, the unfunded cost attributable to such
3 individuals must be distributed over a period of at least five taxable years.

4 Contributions under individual policy pension plans are typically claimed under this
5 rule.

6 The second rule, while occasionally used with individual policy plans, is used
7 primarily in group pension and trust fund plans. This rule permits the employer to
8 deduct the normal cost of the plan plus the amount necessary to amortize any past
9 service or other supplementary pension or annuity credits in equal annual
10 installments over a 10-year period. However, the maximum tax-deductible limit
11 cannot exceed the amount needed to bring the plan to its full-funding limit. The full-
12 funding limit is defined as the lesser of 100 percent of the plan's actuarial accrued
13 liability (including normal cost) or 150 percent of the plan's current liability, reduced
14 by the lesser of the market value of plan assets on their actuarial value. If the plan's
15 actuarial cost method does not generate an accrued liability, the value that would be
16 generated by the entry age normal method is used. The plan's funding standard
17 account credit balance is subtracted from the asset value before determining the full-
18 funding limitation.

19
20 **Q. Do other income tax considerations also apply?**

21 **A.** Yes. If amounts contributed in any taxable year are in excess of the amounts
22 allowed as a deduction for that year, the excess may be carried forward and deducted
23 in succeeding taxable years, in orders of time, to the extent that the amount carried

1 forward to any such succeeding taxable year does not exceed the deductible limit for
2 such succeeding taxable year. However, a 10 percent excise tax is imposed on
3 nondeductible contributions by an employer to a qualified plan. For purposes of the
4 excise tax, nondeductible contributions are defined as the sum of (1) the amount of
5 the employer's contribution that exceeds the amount deductible under Internal
6 Revenue Code section 404 and (2) any excess amount contributed in the preceding
7 tax year that has not been returned to the employer or applied as a deductible
8 contribution in the current year.

9 Additionally, obtaining benefit from taking an income tax deduction for
10 pension funding contributions can also be impacted by other deductions and whether
11 the company has taxable income against which to take a deduction.

12
13 **Q. Does utility management generally have a wide range of discretion as to how
14 much to contribute to funding a defined benefit pension plan in a given year?**

15 **A.** Yes. Utility management's discretion as to how much funding to contribute into the
16 defined benefit pension plan trust for a given year is generally confined by (1) the
17 minimum funding obligation (representing the lowest amount needed to meet the
18 minimum funding obligation, as discussed above) and (2) the maximum tax-
19 deductible funding contribution (which can represent the maximum amount to be
20 considered for the pension funding contribution). Contributions above the
21 minimum funding obligation and up to the maximum tax deductible amount for the
22 year are sometimes referred to as discretionary contributions. For larger pension

1 plans, this range of potential discretionary contributions can amount to hundreds of
2 millions of dollars.

3

4 **Q. Can management's decisions on how much to contribute into a defined benefit**
5 **pension plan also impact the amount of net periodic pension cost in a year?**

6 A. Yes, it can. Generally, the most directly impacted component of NPPC is the
7 expected return on assets for the year. As I discussed above, the expected return on
8 plan assets is derived by applying an expected rate of return to pension trust assets.
9 The expected return on plan assets reduces the net periodic pension cost.

10

11 **Q. What do you recommend as the basis for ratemaking recognition of the cost for**
12 **the Companies' defined benefit pension plans in the current rate cases?**

13 A. I recommend that the SFAS 87 accrual method be used for the ratemaking
14 recognition of the cost for the Companies' defined benefit pension plans in the
15 current rate cases.

16

17 **Q. Is using the SFAS 87 accrual amounts for Pensions consistent with how the**
18 **FirstEnergy utilities budget for Pensions?**

19 A. Yes. The FirstEnergy utilities' budgets for Pensions reflect the SFAS 87 accrual
20 method. FirstEnergy also uses the accrual accounting for its actual Pension costs.

21

22 **Q. What adjustments are produced by using SFAS 87 accrual accounting for**
23 **Pensions in the current rate case?**

1 A. As shown on Schedule C-14 of Exhibits LA-ME-1, LA-PN-1, LA-PP-1 and LA-WP-
2 1, respectively:

- 3 • Pension expense for MetEd is decreased by \$14.045 million;
- 4 • Pension expense for Penelec is decreased by \$6.429 million;
- 5 • Pension expense for Penn Power is decreased by \$3.624 million; and
- 6 • Pension expense for West Penn is decreased by \$7.149 million.

7

8 **C-15, Post Retirement Benefits Other Than Pensions (All Four FE Utilities)**

9 **Q. What have the FirstEnergy Companies proposed for Post Retirement Benefits**
10 **Other Than Pensions in the current case?**

11 A. The FirstEnergy Companies propose to use only the service cost component of
12 Statement of Financial Accounting Standards No. 106 ("SFAS 106") for their
13 requested expense for Post Retirement Benefits Other Than Pensions (also referred
14 to as Other Post Employment Benefits or OPEBs).

15

16 **Q. Is that consistent with how the Companies budget for OPEBs?**

17 A. No. The Companies' budgets for OPEBs appear to include the full FAS 106 cost.

18

19 **Q. What components are included in the SFAS 106 cost for OPEBs?**

20 A. Under Accounting Standards Codification ASC 715 (SFAS 106) for accounting for
21 other postretirement employee benefits (OPEB), companies with defined benefit
22 plans must accrue for financial accounting purposes an expense for retirees' health
23 benefits during the years those employees are working. The components of Net

1 Periodic Post Retirement Benefit Cost ("NPPBC") under SFAS 106 are generally
2 understood to include the following:

- 3 1. Service cost - the cost of benefits accruing in the current period;
- 4 2. Interest cost - interest on the Accumulated Postretirement Benefit Obligation;
- 5 3. Expected return on plan assets - anticipated earnings on plan assets;
- 6 4. Amortization of net transition amount - net transition amount is the difference
7 between APBO and plan assets when FAS 106 was first adopted; and
- 8 5. Net amortization and deferrals.
 - 9 a) Amortization of gains and losses - a gain or loss is the change in APBO
10 resulting from a change in assumptions or experience.
 - 11 b) Prior service cost (plan amendment) - the change in the APBO due to a plan
12 amendment.

13
14 The NPPBC is thus the result of these components:

15
$$\text{NPPBC} = \text{service cost} + \text{interest cost} - \text{expected return on plan assets} \pm \text{amortizations}$$

16

17 **Q. How were OPEB expenses addressed in the last Met-Ed and Penelec rate cases?**

18 A. It appears that the OPEB expense was based on only the service cost component in
19 the last Met-Ed and Penelec rate cases.

20

21 **Q. Does focusing only on the service cost component result in proper accounting
22 for OPEB costs?**

23 A. No, it does not. Any company that reported only the service cost component for its
24 OPEBs on its financial statements would be in violation of GAAP.

25

26 **Q. Is focusing only the service cost component of OPEBs also contrary to how the
27 FirstEnergy utilities budget for OPEBs?**

1 A. Yes. The FirstEnergy utilities' budgets for OPEBs reflect the SFAS 106 accrual
2 method. FirstEnergy also uses the accrual accounting for its actual OPEB costs.

3

4 **Q. Could using only the service cost component of OPEB cost over-recover the cost**
5 **versus the budgeted amounts?**

6 A. Yes, it could, and this over-recovery versus budgeted amounts also appears to be the
7 scenario reflected in the Companies' filings, where they are making a pro forma
8 adjustment to increase their budgeted amounts for OPEB, which are based on SFAS
9 106 accruals. They are thus requesting more than their budgeted expense.

10

11 **Q. Of what regulatory guidance concerning OPEB costs for ratemaking purposes**
12 **have you been made aware?**

13 A. OCA has advised me that the Pennsylvania regulations include 52 Pa. Code § 69.351
14 which provides as follows a policy statement concerning OPEBs and FAS 106:

15 § 69.351. Implementation of Statement of Financial
16 Accounting Standards for Rule No. 106 (SFAS 106)—
17 statement of policy.

18 (a) Effective with financial statements for fiscal years
19 beginning after December 15, 1992, SFAS 106 provides the
20 generally accepted accounting principles to be used by large
21 companies in accounting for post-retirement benefits other
22 than pensions (OPEBs). Up to now, companies which
23 provided OPEBs for their employers used the pay-as-you-go
24 (cash) basis. Each year a company would record on its books
25 the actual cash paid for OPEBs.

26 (b) SFAS 106 operates on the premise that post-retirement
27 benefits are a form of deferred compensation whereby an
28 employer promises to exchange future benefits for current
29 service. SFAS 106 requires companies to switch to the
30 accrual method of accounting for OPEBs. As guidance to
31 utilities wishing to implement SFAS 106, the Commission

1 provides the following guidelines regarding the rulemaking
2 treatment of OPEBs:

3 (1) Each jurisdictional utility which has satisfied the
4 appropriate customer notice requirements, presented sufficient
5 documentation to support its SFAS 106 cost estimates and
6 presented sufficient cost containment measures, may seek
7 formal Commission approval to record on its books a
8 regulatory asset pursuant to SFAS 71 equal to the difference
9 between its current rate recognition of OPEB costs and its
10 accrued liability for the expenses under SFAS 106 subject to
11 recovery in future rate proceedings to the extent that the costs
12 are prudently incurred and demonstrated to be reasonable.

13 (2) The funding of a dedicated trust for the deferred amounts
14 is not required at this time. A utility should maintain separate
15 balance sheet accounts for both the accrued liability and the
16 regulatory asset along with sufficient records to allow a
17 detailed analysis of the accounts.

18 (3) The Commission intends to move jurisdictional utilities to
19 SFAS 106 accrual accounting for ratemaking purposes within
20 approximately 5 years and to allow the recovery in base rates
21 of deferred amounts in approximately 20 years, to the extent
22 that OPEB costs are prudently incurred and examined for
23 reasonableness in a base rate proceeding prior to rate
24 recognition.

25 (4) If the Commission, after examination, grants current rate
26 recognition of OPEB costs exceeding the pay-as-you-go
27 amount, the excess amount should be placed in a dedicated
28 trust fund.

29 (5) The Commission will monitor the development of changes
30 in OPEB costs as a result of both government policy changes
31 and company cost containment efforts.
32

33 **Q. When was SFAS 106 adopted as part of Generally Accepted Accounting**
34 **Principles ("GAAP")?**

35 **A.** SFAS 106 was adopted as part of GAAP in December 1990. As noted in § 69.351,
36 the Implementation of Statement of Financial Accounting Standards for Rule No.
37 106 statement of policy, quoted above: "Effective with financial statements for
38 fiscal years beginning after December 15, 1992, SFAS 106 provides the generally

1 accepted accounting principles to be used by large companies in accounting for post-
2 retirement benefits other than pensions (OPEBs).”

3
4 **Q. Should the FirstEnergy utilities be moved to full SFAS 106 accrual accounting**
5 **in the current rate cases?**

6 A. Yes. In accordance with the statement of policy in § 69.351, SFAS 106 accrual
7 accounting should be used in the current rate cases. This is also consistent with how
8 the FirstEnergy utilities budget for OPEB costs and with the guidance provided in
9 this statement of policy.

10
11 **Q. What adjustments are produced by using SFAS 106 accrual accounting for**
12 **OPEBs in the current rate case?**

13 A. As shown on Schedule C-15 of Exhibits LA-ME-1, LA-PN-1, LA-PP-1, and LA-
14 WP-1, respectively:

- 15 • OPEB expense for Met-Ed is decreased by \$2.814 million;
- 16 • OPEB expense for Penelec is decreased by \$1.281 million;
- 17 • OPEB expense for Penn Power is decreased by \$778,000; and
- 18 • OPEB expense for West Penn is decreased by \$417,000.

19
20 **Q. Does this conclude your direct testimony?**

21 A. Yes, it does.

ATTACHMENT
RCS-1

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA	
&76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA	
& 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001	
& ER-85647001	New England Power Company (FERC)
850782-EI &	
850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU	
& 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
T E-1032-88-102	Illinois Bell Telephone Company (Illinois CC)
89-0033	Puget Sound Power & Light Company (Washington UTC))
U-89-2688-T	Philadelphia Electric Company (Pennsylvania PUC)
R-891364	Potomac Electric Power Company (District of Columbia PSC)
F.C. 889	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
Case No. 88/546*	
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
& U-1551-89-103	Hawaiian Electric Company (Hawaii PUC)
Docket No. 6998	Intrastate Access Charge Methodology, Pool and Rates
TC-91-040A and	Local Exchange Carriers Association and South Dakota
TC-91-040B	Independent Telephone Coalition
9911030-WS &	General Development Utilities - Port Malabar and
911-67-WS	West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314	
& M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 &	
U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 &	Citizens Utilities Company - Gas Division
U-1032-93-193	(Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/	Sale of Assets CC&N from Contel of the West, Inc. to
E-1032-93-169	Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed Staff Investigation E-1032-95-473 E-1032-95-433	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission) Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC) Citizens Utility Co. - Arizona Electric Division (Arizona CC) Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285 94-10-45 A.96-08-001 et al.	Missouri Gas Energy (Missouri PSC) Southern New England Telephone Company (Connecticut PUC) California Utilities' Applications to Identify Sunk Costs of Non- Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324 96-08-070, et al.	Bell Atlantic - Delaware, Inc. (Delaware PSC) Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12 R-00973953	Connecticut Light & Power (Connecticut PUC) Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power & Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705 E-1072-97-067 Non-Docketed Staff Investigation PU-314-97-12 97-0351 97-8001	Entergy Gulf States, Inc. (Cities Steering Committee) Southwestern Telephone Co. (Arizona Corporation Commission) Delaware - Estimate Impact of Universal Services Issues (Delaware PSC) US West Communications, Inc. Cost Studies (North Dakota PSC) Consumer Illinois Water Company (Illinois CC) Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I 9355-U 97-12-020 - Phase I U-98-56, U-98-60, U-98-65, U-98-67 (U-99-66, U-99-65, U-99-56, U-99-52) Phase II of 97-SCCC-149-GIT PU-314-97-465 Non-docketed Assistance Contract Dispute	San Diego Gas & Electric Co., Section 386 costs (California PUC) Georgia Power Company Rate Case (Georgia PUC) Pacific Gas & Electric Company (California PUC) Investigation of 1998 Intrastate Access charge filings (Alaska PUC) Investigation of 1999 Intrastate Access Charge filing (Alaska PUC) Southwestern Bell Telephone Company Cost Studies (Kansas CC) US West Universal Service Cost Model (North Dakota PSC) Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC) City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL) Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC)
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No.	
98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
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P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
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U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
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96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
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05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
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PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
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E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
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PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
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G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
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09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
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09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)

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R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
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10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
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U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
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10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
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G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)
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R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
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A.10-12-005	San Diego Gas & Electric Company (California PUC)
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E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
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E-01933A-12-0291	Tucson Electric Power Company (Arizona CC)
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12-1649-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-04204A-12-0504	UNS Electric, Inc. (Arizona CC)
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U-14-001	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
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